2024 RTO Membership Analysis

Section 1: Overview and Summary

Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively "Companies") are required by the Kentucky Public Service Commission ("KPSC" or "Commission") to annually file a report evaluating whether joining a regional transmission organization ("RTO") would be in the best interest of customers.[1] This 2024 RTO Membership Analysis builds on work performed in the previous RTO reports and extensive information related to RTOs that was filed in Case No. 2022-00402. The primary conclusions of this year's analysis are:

1. Midcontinent Independent System Operator, Inc. ("MISO") and PJM Interconnection, L.L.C. ("PJM") continue to modify their market rules to address concerns about resource adequacy. In particular, the PJM Base Residual Auction ("BRA") results announced on July 30, 2024, showed a significant increase in capacity prices for delivery year 2025/2026. Until such time as MISO and PJM consistently demonstrate that their markets are capable of attracting new generation resources to maintain reliability, the Companies do not support initiating detailed discussions with MISO or PJM regarding membership.
2. Due to uncertainty regarding RTO reliability and related capacity market reforms in MISO and PJM and each RTO's concerns about the reliability impact of the U.S. Environmental Protection Agency's ("EPA") Clean Air Act Section 111(b) and (d) greenhouse gas regulations ("Greenhouse Gas Rules"), attempting to model the Companies' membership in either RTO is not practical to the degree necessary to confidently make a decision to join one of them.
3. Retail choice is one of the primary reasons that RTOs can struggle to ensure resource adequacy because retail providers do not have a long-term obligation to serve. In PJM, eight of the thirteen states and District of Columbia allow retail choice, whereas in MISO only three of the fifteen states allow retail choice. Therefore, the Companies are likely to focus more attention on MISO developments in the future because their membership may better align with the Companies' obligation to serve.[2]
4. In its final order in Case No. 2022-00402, the Commission stated, "This Commission has no interest in allowing our regulated, vertically-integrated utilities to effectively depend on the market for generation or capacity for any sustained period of time."[3] This requirement, along with recent PJM capacity accreditation rating reforms, would increase the Companies' capacity needs in PJM and would eliminate the potential for capacity and energy savings that were a primary source of potential RTO savings.

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[1] *See Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates*, Case No. 2018-00294, Order (Ky. PSC Apr. 30, 2019); *Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates*, Case No. 2018-00295, Order (Ky. PSC Apr. 30, 2019).

[2] Retail choice states in PJM are Delaware, Illinois, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, and the District of Columbia. Retail choice states that have load in MISO are Illinois, Michigan, and Texas.

[3] *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan*, Case No. 2022-00402, Order at 177 (Ky. PSC Nov. 6, 2023).

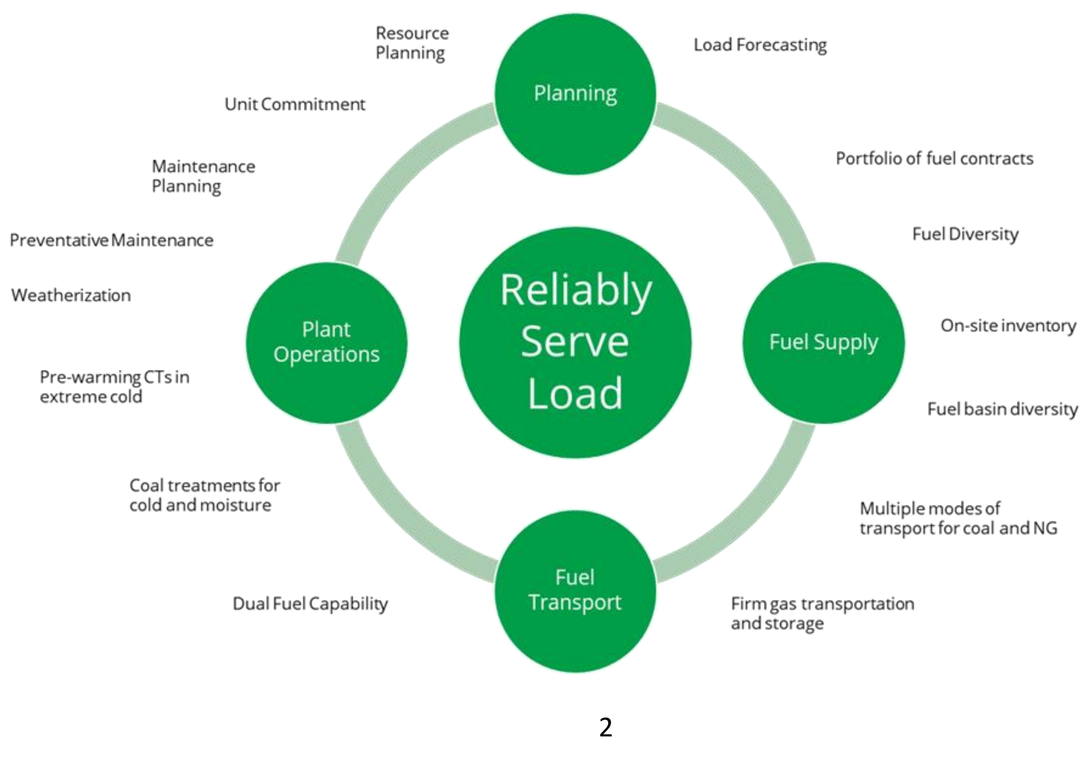
For the reasons stated above, this report focuses on the reliability and market issues that are ongoing in both MISO and PJM and the challenges each RTO faces in addressing its future capacity and energy needs. It also describes the fundamental differences between operating as a standalone utility and operating inside an RTO (e.g., capacity planning, fuel planning and procurement, unit commitment and dispatch).

The Companies remain open to the possibility of future RTO membership, and they believe that continuing to study it, albeit perhaps less frequently than the current annual requirements (e.g., only in conjunction with the triennial IRP filing), is entirely appropriate. Less frequent study would allow more time between studies for RTOs to address the numerous issues related to resource adequacy and EPA regulations and to demonstrate some degree of stability. Stability and certainty are important in a decision to join an RTO because it is likely to be challenging and costly to undo such a decision. Therefore, prudence requires that the benefits be clear and durable before making such a decision and commitment on behalf of the Companies' customers.

<u>Section 2: Key Difference in Operating as a Standalone Utility versus in an RTO</u>

A decision to join an RTO must include a thorough consideration of the vast operational differences relative to being an independent vertically integrated utility (as the Companies currently operate), as well as the operational differences between the RTOs themselves.

As a standalone, vertically integrated utility, the Companies are solely responsible for all aspects of planning and operating to reliably serve their customers' energy needs 8,760 hours a year across a broad range of possible future conditions. The Companies are also responsible for ensuring that their generation fleet is compliant with all current EPA regulations and for making changes to that fleet to comply with future EPA regulations. The following figure illustrates, at a high level, the continuous cycle of long-term and short-term generation-related planning and operational activities in which the Companies engage to ensure reliable service to customers.



In an RTO, there are numerous parties that can (and do) perform these functions in response to, and to comply with, various RTO markets, tariffs, and rules. RTO markets are highly structured mechanisms whose rules are set through processes approved by the Federal Energy Regulatory Commission ("FERC"). It is via these markets that the RTO is to ensure that the grid has adequate generation and energy to reliably serve customers. However, both MISO and PJM in recent years have indicated a growing concern that their markets may, or are, not adequately procuring generation for the future.

Concerns about whether RTO markets, as they have historically operated, can be modified to address future reliability have been expressed by many industry observers. For example, current FERC Commissioner Mark Christie published a detailed discussion of the challenges facing RTO markets in 2023 in the Energy Law Journal entitled, "It's Time to Reconsider Single-Clearing Price Mechanisms in U.S. Energy Markets," in which he stated:

> [L]et's not pretend capacity markets, with their administratively set demand curves and scarcity prices, are true markets that are more efficient at predicting the future because of the Hayekian collective intelligence of the marketplace. They are just another way to transfer money from consumers to generation investors to try to ensure sufficient power supply in the future. Not that there's anything wrong with that in concept. If Americans are not willing to live with regular power supply shortages – and we are not – then it is necessary to pay in advance for resources to make sure they are there whenever needed, just like buying an insurance policy that may never be used. Just don't pretend, however, that what's at work in capacity markets is Adam Smith's invisible hand efficiently allocating capital through a single-clearing price mechanism.
>
> And that raises the following question: How can this administrative pricing mechanism used in capacity markets -- with the complexities and subjectivity of an administratively set demand curve, administratively set local deliverability areas used to calculate zonal prices to load, administrative determination of CONE, administrative judgments about effective load carrying capabilities, offer caps, etc.-- possibly be described as the "market" alternative to the "regulated" construct of paying for needed generation through rate base, or purchasing needed power through bilateral contracts? To the honest observer RTO capacity markets and state IRP processes are both planning constructs, just in different forms. This article suggests that most state IRP processes may be far better suited to plan comprehensively, to manage the risks associated with different types of generation, to incorporate demand-side resources, and to balance state policies promoting renewables with the core goals of delivering reliability and controlling consumer costs than RTO capacity markets are.[4]

It is important to keep in mind that, functionally, MISO and PJM do not own generation resources nor transmission lines, but coordinate the flow of electricity across their respective geographical footprints over the high-voltage transmission system. They are both responsible for maintaining a fair and competitive wholesale market for electricity, where buyers and sellers can have equal access to the grid. They, however, are not responsible for the distribution of electricity to end consumers, as this is handled

[4] Mark C. Christie, "It's Time to Reconsider Single-Clearing Price Mechanisms in U.S. Energy Markets," Energy Law Journal Vol. 41.1 at 15-16 (May 2, 2023), available at https://www.eba-net.org/wp-content/uploads/2023/05/3-Commr-Christie1-30-1.pdf.

by local distribution companies or utilities. They have extensive stakeholder committee processes for designing and revising complex market and reliability rules to ensure the price of wholesale electricity transparently reflects supply and demand fundamentals and that the supply of electricity meets demand every hour of the year. The various stakeholder groups include generation resource owners, independent power providers, power marketers, Independent Market Monitors, consumer advocacy groups, state regulators, utilities, and others.

PJM and MISO use the four markets described below to balance wholesale electricity supply and demand in every hour of every year. In these markets, load pays market prices and generation receives market prices. Thus, an important activity for a load-serving entity ("LSE") in an RTO is to financially balance and hedge load's market price risk with generation revenues.

Capacity Market

PJM's capacity market provides financial signals to generation owners to make investments in existing generation resources, build new generation resources, and retire generation resources that have reached the end of their useful life while meeting long-term reliability objectives. Each capacity auction, known as a Base Residual Auction ("BRA"), is held three years in advance of the delivery year, using BRA-specific peak load forecast and expected resource mix. Capacity owners economically bid into the capacity auction, taking into consideration, among other things, long-term fixed costs, operations and maintenance costs, fuel costs, environmental regulation compliance costs, and profitability margin. The bidders that clear the auction receive capacity revenue based on their location for every MW of capacity they commit to be available to supply energy when needed by PJM.

MISO's capacity market provides financial signals to market participants representing LSEs to make investments in existing generation resources, build new generation resources, and retire generation resources that have reached the end of their useful life while meeting resource adequacy objectives. Known as the Planning Resource Auction ("PRA"), it is a seasonal resource adequacy construct that was originally approved by FERC in August 2022 and implemented by MISO beginning the 2023/2024 Planning Year. The new seasonal approach was adopted to provide better clarity into the seasonal resource adequacy needs in each Local Resource Zone and match that more precisely to the seasonal performance attributes of generation resources. It is conducted in April every year to establish a separate auction price for each season (summer, fall, winter, and spring) of the next planning year, which begins June 1.

Day-Ahead Energy Market

Generation owners bid their electricity supply into the day-ahead market to meet forecast demand for the following day, providing enough time for resources that clear the market to make the necessary preparations to generate electricity. Individual generators are incentivized to minimize costs and maximize profitability. Among other costs, depending on the generation resource, bid considerations include the cost of fuel, fixed and variable operations and maintenance, natural gas pipeline transportation, transmission, emission allowances, and profit margin. Note that the Day-Ahead Energy Market is just a financial settlement because no actual load is served on a day-ahead basis; actual load is only served in real-time.

Real-Time Energy Market

Differences between forecast and actual demand during the operating day and as cleared in the Day-Ahead market are resolved in the real-time market by PJM. PJM remedies supply shortages by procuring the lowest cost supply from generators that are synchronized to the grid and able to immediately supply energy. Just as in the day-ahead market, generators are incentivized to minimize costs and maximize the profitability of their units when bidding into the real-time market. Essentially, load and generation pay or receive differences in the volumes that cleared the Day-Ahead market at the real-time LMP.

Ancillary Services Market

PJM and MISO have other specialized products and services that they procure to control the critical balance of supply and demand on their respective grids (such services are "ancillary services"). Ancillary services markets help "ensure that there are adequate electric reserves to maintain reliability and sufficient voltage to enable the grid to operate."[5]

Conclusion

The primary difference between the Companies' planning and operating as a standalone utility versus planning and operating in an RTO can be summarized in one word: control. As a standalone utility, the Companies are a one-stop shop for planning and operating their generation fleet. The Companies interact with regional energy markets to optimize energy costs and off-system sales benefits for customers, but they do not depend on regional markets. Customers pay the prudently incurred costs for the Companies' generation fleet, and the Commission has clear oversight and authority over those costs. Conversely, because RTOs have many stakeholders, as RTO members the Companies would have limited influence over the RTO's market tariffs and rules that may or may not be beneficial to the Companies' customers.

Section 3: Markets in Transition: Resource Adequacy Concerns in PJM and MISO as They Modify Market Rules to Accommodate Increasing Load and Adapt to a Changing Resource Mix

Growing concerns regarding resource adequacy in PJM and MISO are receiving increasing attention by the RTOs themselves, industry observers, and regulators. With different stakeholder groups and different existing market tariffs, MISO and PJM are taking somewhat different approaches to their market redesigns to attempt to address future capacity and energy reliability concerns. It is interesting to observe that one of the consequences of each RTO's efforts is that capacity prices have risen dramatically from recent levels. This is as should be expected because each RTO is trying to send a price signal via each capacity market that existing generation should consider remaining operational and that new generation (particularly non-intermittent technology) is urgently needed. However, because load always pays market price, the increase in prices has not been well received by many, despite the need for future generation capacity and energy.

[5] FERC, "Participation in Midcontinent Independent System Operator (MISO) Processes: An Introductory Guide to Participation in Midcontinent Independent System Operator (MISO) Processes," available at https://www.ferc.gov/participation-midcontinent-independent-system-operator-miso-processes (accessed Oct. 12, 2024).

PJM

Key events in recent months include:

- December 19, 2023 - FERC approves settlement to reduce non-performance charges incurred during Winter Storm Elliott by 32%.[6]
- January 30, 2024 - FERC approves Critical Issue Fast Path ("CIFP") capacity market reforms.[7]
- July 2024 - PJM's 2025/2026 Base Residual Auction held, implementing new FERC-approved CIFP market reforms.
    - RTO capacity prices increased to $269.92/MW-day for 2025/2026 compared to $28.92/MW-day for the 2024/2025 BRA.[8]

2025/2026 BRA Complaints

The dramatic increase in capacity prices from $28.92/MW-day to $269.92/MW-day in the recent 2025/2026 BRA produced a flurry of comments and complaints from stakeholders. This was the first auction to incorporate the CIFP market reforms approved by FERC in January 2024.[9] However, the exclusion of Reliability Must Run ("RMR") units from the capacity auction supply pool became a central theme in many stakeholder concerns. When a generation plant owner notifies PJM of their intent to retire generation capacity, Transmission Owners will conduct a Reliability Analysis. If that Reliability Analysis shows reliability violations, PJM may formally request that a plant continue operating under a Reliability Must Run agreement until the transmission system can be upgraded to allow the unit to retire without reliability violations.

- On September 27, 2024, several Public Interest Organizations ("PIOs") filed a complaint with FERC about the exclusion of RMR units from the capacity auction supply pool, arguing that doing so artificially inflated capacity prices and that the upcoming 2026/2027 BRA should be delayed until the RMR issues are resolved.[10]

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[6] *PJM Interconnection L.L.C.*, FERC Docket No. ER23-2975-000, Order (FERC Dec. 19, 2023), available at https://elibrary.ferc.gov/eLibrary/docketsheet?docket_number=er23-2975&sub_docket=all&dt_from=1960-01-01&dt_to=2023-12-31 (accessed Oct. 12, 2024).

[7] *PJM Interconnection L.L.C.*, FERC Docket No. ER24-99-000, Order (FERC Jan. 30, 2024), available at https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20240130-3113&optimized=false (accessed Oct. 12, 2024).

[8] PJM, "2025/2026 Base Residual Auction Results" at 5 (Aug. 21, 2024), available at: https://pjm.com/-/media/committees-groups/committees/mrc/2024/20240821/20240821-item-08---2025-2026-base-residual-auction---presentation.ashx (accessed Oct. 12, 2024).

[9] *PJM Interconnection L.L.C.*, FERC Docket No. ER24-99-000, Order (FERC Jan. 30, 2024), available at https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20240130-3113&optimized=false (accessed Oct. 12, 2024).

[10] *Sierra Club et al. v. PJM Interconnection, L.L.C.*, FERC Docket No. EL24-148-000, Complaint of Sierra Club, Natural Resources Defense Council, Sustainable FERC Project, and Union of Concerned Scientists (Sept. 27, 2024), available at: https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20240927-5073&optimized=false (accessed Oct. 12, 2024).

- Governmental consumer advocates for Maryland, Delaware, the District of Columbia, Illinois, New Jersey, and Ohio previously raised similar RMR agreement concerns to the PJM Board on August 30, 2024.[11]
- Monitoring Analytics' (PJM's Independent Market Monitor, "IMM") analysis of the 2025/2026 BRA found many flawed market rules. Though the IMM did not take issue with excluding RMR units from the supply stack per se, it concluded that doing so increased capacity prices by roughly $4.3 billion.[12]
- On September 27, 2024, the Organization of PJM States Inc. ("OPSI"), which represents state utility commissions, raised six market flaws that PJM urgently needed to address. Of the six, four high-priority items (the first of which was RMR units) needed resolution prior to the next capacity auction (2026/2027), currently slated for December 2024. They argued temporarily delaying the next auction to provide enough time to resolve them should also be considered.[13]
- On October 8, 2024, OPSI filed comments agreeing with the complaint filed at FERC by several PIOs on September 27, 2024, but added that they believed the cost of excluding RMR units from generation supply in the upcoming 2026/2027 BRA alone could cost rate payers as much as $14.5 billion.[14]
- PJM has defended the exclusion of RMR units from auction supply, stating that the ongoing trend of dispatchable generation retirement, slow new entry of dispatchable generation, long interconnection queues, and load growth necessitated a strong price signal to provide incentives for new dispatchable generation to be built.[15]

New Capacity Concerns

In addition to the discussions around the 2025/2026 auction results, serious concerns remain with respect to building new dispatchable generation. The 2025/2026 BRA procured only 110.3 MW of new

[11] David S. Lapp, People's Counsel, Maryland Office of People's Counsel; Ruth Ann Price, Acting Public Advocate, Delaware Division of the Public Advocate; Sandra Mattavous-Frye, People's Counsel, Office of the People's Counsel for the District of Columbia; Sarah Moskowitz, Executive Director, Citizens Utility Board of Illinois; Brian O. Lipman, Director, New Jersey Division of Rate Counsel; Maureen R. Willis, Consumers' Counsel, Office of the Ohio Consumers' Counsel, "Urgent Reforms to the PJM Capacity Market Regarding Reliability Must Run Units" (Aug. 30, 2024), available at: https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/2024/20240903-consumer-advocate-letter-on-capacity-markets.ashx (accessed Oct. 12, 2024).

[12] Monitoring Analytics, "Analysis of the 2025/2026 RPM Base Residual Auction, Part A" at 2 (Sept. 20, 2024), available at: https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_A_20240920.pdf (accessed Oct. 12, 2024).

[13] OPSI, Letter (Sept. 27, 2024), available at: https://pjm.com/-/media/about-pjm/who-we-are/public-disclosures/2024/20240927-opsi-letter-re-results-of-the-2025-2026-bra.ashx (accessed Oct. 12, 2024).

[14] *Sierra Club et al. v. PJM Interconnection, L.L.C.*, FERC Docket No. EL24-148-000, Comments and Motion to Lodge of the Organization of PJM States, Inc. at 3 (Oct. 8, 2024), available at: https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20241008-5114&optimized=false (accessed Oct. 12, 2024).

[15] PJM, Letter at 1-2 (Sept. 19, 2024), available at; https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/2024/20240919-pjm-board-response-consumer-advocates-letter-re-urgent-reforms-pjm-capacity-market-re-reliability-must-run-units.ashx (accessed Oct. 12, 2024).

generation.[16] As of September 13, 2024, only 2,000 MW of new generation had been put into service in PJM in 2024, nearly all solar.[17] According to PJM Inside Lines, PJM's official company news source, "That pace is trending below the lowest annual number of megawatts of new generation added to the grid in PJM's history."[18] Similarly, a PJM official stated in a recent Markets and Reliability Committee meeting, "While PJM continues to execute against the [interconnection] transition plan, concerns are growing that the construction build-out from the volume of applications has not yet materialized."[19] Some 38,000 MW of new generation have cleared the PJM interconnection queue but have yet to be built due to various issues ranging from financing, supply chain, and siting and permitting challenges.[20]

Not only is it challenging to build new dispatchable generation capacity, but it remains challenging to permit and build the supporting pipeline infrastructure to support specifically dispatchable natural gas-fired generation.

On July 30, 2024, the United States Court of Appeals for the District of Columbia Circuit vacated and remanded FERC's authorization of Transcontinental Gas Pipe Line Company, LLC's ("Transco") 0.8 Bcf/day Regional Energy Access ("REA") pipeline expansion project serving customers in Pennsylvania, New Jersey, and Maryland.[21] Environmental groups challenged FERC's approval of the project, questioning the need for the expansion project as well as FERC's assessment of the project's greenhouse gas emissions.

According to PJM's recent comments to FERC supporting a temporary emergency certificate for the REA project, shutting down the REA project, which also would involve replacing existing system facilities supporting 1.2 Bcf/day of existing firm contracts, would threaten over 2 Bcf/day of gas supply and "could have potentially adverse impacts on PJM's ability to maintain reliability over the upcoming 2024-2025 winter and beyond…."[22] PJM further stated, "The electric reliability impacts from the approximately 22.6

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[16] PJM, "2025/2026 Base Residual Auction Report" at 7 (June 30, 2024) ("[T]he 2025/2026 BRA procured 110.3 MW of capacity from new generation and 753.8 MW from uprates to existing or planned generation. The quantity of new generation is down from the previous BRA where there was 328.5 MW of new generation."), available at: https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-report.ashx (accessed Oct. 12, 2024).

[17] PJM, "Commercial Deployment of New Generation" at 8 (Sept. 25, 2024), available at: https://pjm.com/-/media/committees-groups/committees/mrc/2024/20240925/20240925-item-09---pjm-interconnection-queue---presentation.ashx (accessed Oct. 12, 2024).

[18] PJM Inside Lines, "As Interconnection Reform Sees Success, PJM Focuses on Post-Study Obstacles" (Sept. 25, 2024), available at: https://insidelines.pjm.com/as-interconnection-reform-sees-success-pjm-focuses-on-post-study-obstacles/ (accessed Oct. 12, 2024).

[19] Ethan Howland, "PJM says 'concerns are growing' after less than 2 GW added this year," Utility Dive (Sept. 26, 2024), available at: https://www.utilitydive.com/news/pjm-interconnection-capacity-online-construction-shortfall-vc-renewables/728145/ (accessed Oct. 12, 2024).

[20] PJM, "PJM Capacity Auction Procures Sufficient Resources To Meet RTO Reliability Requirement: Tighter Supply/Demand Balance Drives Higher Pricing Across the Region" (July 30, 2024), available at: https://www.pjm.com/-/media/about-pjm/newsroom/2024-releases/20240730-pjm-capacity-auction-procures-sufficient-resources-to-meet-rto-reliability-requirement.ashx (accessed Oct. 12, 2024).

[21] *N.J. Conservation Found. v. FERC*, 111 F.4th 42 (D.C. Cir. July 30, 2024), available at https://www.ferc.gov/media/new-jersey-conservation-foundation-et-al-v-ferc-2 (accessed Oct. 12, 2024).

[22] *Transcontinental Gas Pipe Line Company, LLC*, FERC Docket No. CP21-94-004, PJM Interconnection, L.L.C.'s Comments in Support of Transcontinental Gas Pipe Line Company, LLC for a Temporary Emergency Certificate at 2-3 (Oct. 7, 2024), available at https://www.pjm.com/-/media/documents/ferc/filings/2024/20241007-cp21-94-004.ashx (accessed Oct. 12, 2024).

percent reduction of Transco's delivery capacity into the region would … affect the availability of almost 10 percent of the electric capacity (unforced) needed to meet one of PJM's electric subregion's reliability requirement. Such loss of necessary fuel supply— without any opportunity to obtain replacements before the upcoming winter—could prove severely problematic."[23]

The IMM filed comments with FERC supporting Transco's application for a temporary certificate to allow it to continue operating the REA project and underlining the urgent need for the expansion project and additional pipeline capacity in general, citing its 2023 State of the Market report published on March 14, 2024.[24] The IMM estimated that between 1.9 Bcf/day and 4.8 Bcf/day of additional firm natural gas pipeline capacity would need to be built in PJM's footprint to replace retiring dispatchable base load generation over the coming years.[25] According to the IMM, this would facilitate system reliability while complementing the growing intermittent generation resource fleet.[26]

2026/2027 BRA

New build issues also loom for the 2026/2027 BRA because it is uncertain whether new generation can be built in time to participate in that delivery year. Additionally, the auction parameters used in the 2026/2027 BRA could result in capacity prices jumping again from $269.92/MW-day to as high as $695/MW-day.[27] The peak load forecast for the 2026/2027 delivery year is 2.2% higher than the 2025/2026 BRA, increasing the Reliability Requirement, reflecting the target reserve level to procure in the auction, by 1.9%.[28] The reference resource used in the 2026/2027 BRA is also changing to a natural gas combined cycle (CC) from a natural gas combustion turbine (CT) used in the 2025/2026 BRA.[29] This has significant capacity auction implications as the auction demand curve is developed in part by the Gross Cost of New Entry (CONE) of the reference resource, and the Gross CONE of a CC is much higher than that of a CT.[30]

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[23] *Id.* at 3.

[24] *Transcontinental Gas Pipe Line Company, LLC*, FERC Docket No. CP21-94-004, Comments of the Independent Market Monitor for PJM at 2-3 (Oct. 8, 2024), available at: https://www.monitoringanalytics.com/filings/2024/IMM_Comments_Docket_No_CP21-94-004_20241008.pdf (accessed Oct. 12, 2024).

[25] Monitoring Analytics, LLC, "State of the Market Report for PJM, Volume 2, Section 7: Net Revenue" at 392 (Mar. 14, 2024), available at: https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2023/2023-som-pjm-sec7.pdf (accessed Oct. 12, 2024).

[26] *Transcontinental Gas Pipe Line Company, LLC*, FERC Docket No. CP21-94-004, Comments of the Independent Market Monitor for PJM at 3 (Oct. 8, 2024), available at: https://www.monitoringanalytics.com/filings/2024/IMM_Comments_Docket_No_CP21-94-004_20241008.pdf (accessed Oct. 12, 2024).

[27] "The Variable Resource Requirement (VRR) Curve defines the maximum price for a given level of Capacity Resource commitment relative to the applicable reliability requirement". The RTO Gross CONE of $695.83 / MW-Day is designated as point "A" and the highest price point on the 2026/2027 BRA VRR Curve, per the auction Planning Parameters. Thus, the price cap for the 2026/2027 BRA is $695.83 / MW-Day. https://www.pjm.com/-/media/documents/manuals/m18.ashx, pgs. 143, 144, 245.

[28] PJM Interconnection, LLC, "2026/2027 RPM Base Residual Auction Planning Period Parameters" at 1 (Aug. 26, 2024), available at https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2026-2027/2026-2027-planning-period-parameters-for-base-residual-auction-pdf.ashx (accessed Oct. 12, 2024).

[29] *Id.* at 5.

[30] *Id.*

Also, due to the complaint case opened at FERC concerning the 2025/2026 BRA discussed in the *2025/2026 BRA Complaints* section above, PJM announced on October 11, 2024, its intent to request a six-month delay in the 2026/2027 BRA to resolve the issues raised in the complaint before conducting the next auction.[31] PJM's statement suggested that further market reforms could be forthcoming:

> PJM will be supporting a delay of the PJM 2026/2027 Base Residual Auction for approximately six months. PJM does not take auction delay lightly, as the schedule for these auctions has already been compressed due to previous reform efforts. … Further, this delay will allow PJM to discuss with its Members, stakeholders and the PJM Board of Managers the possibility of other capacity market reforms that could occur through a Federal Power Act section 205 filing.[32]

This highlights the difficulty of attempting to analyze RTO membership quantitatively with any meaningful degree of certainty. Putting aside other significant uncertainties, the potential costs and benefits can shift considerably across capacity auctions as the rules of the auctions continue to change.

MISO

Key events in recent months include:

- March 28, 2024 - In an attempt to address the challenges presented by a changing resource mix with higher levels of intermittent generation, MISO filed tariff changes with FERC to implement a new capacity accreditation method to be in place for the 2028/2029 planning year.[33] This filing is still pending.
    - This new method "measures a resource's availability when reliability risk is the greatest."[34] It "first measures a resource's expected marginal contribution to reliability using Resource Class-level performance during the loss of load expectation ("LOLE") analysis."[35] It then uses historical resource-specific performance during reliability risk hours to arrive at the resource level capacity accreditation.[36]

[31] PJM, "Stakeholder," available at https://go.pjm.com/webmail/678183/1180215207/b19206215435bd981f743fe618c0c1f4d66b0ccc7e4fb079703a5731fa709c91 (accessed Oct. 14, 2024); Ethan Howland, "PJM plans to delay upcoming capacity auction by six months," Utility Dive (Oct. 11, 2024), available at https://www.utilitydive.com/news/pjm-interconnection-delay-capacity-auction-ferc-opsi-sierra-club/729580/ (accessed Oct. 14, 2024).

[32] PJM, "Stakeholder," available at https://go.pjm.com/webmail/678183/1180215207/b19206215435bd981f743fe618c0c1f4d66b0ccc7e4fb079703a5731fa709c91 (accessed Oct. 14, 2024).

[33] MISO, "Fact Sheet: MISO filed accreditation approach with FERC as next phase of Resource Adequacy reform," available at https://cdn.misoenergy.org/Fact%20Sheet%20FERC%20Resource%20Accreditation%20Filing632372.pdf (accessed Oct. 12, 2024).

[34] *Midcontinent Independent System Operator, Inc.'s Filing to Reform MISO's Resource Accreditation Requirements*, FERC Docket No. ER24-1638-000, MISO Filing at 3 (Mar. 28, 2024), available at https://cdn.misoenergy.org/2024-03-28%20Docket%20No.%20ER24-1638-000632361.pdf (accessed Oct. 12, 2024).

[35] *Id.*

[36] *Id.* at 3-4.

- June 27, 2024 - FERC approves sloped demand curves to begin use in the 2025 Planning Resource Auction.[37]
    - Since the 2009/2010 Planning Year auction, MISO used a vertical demand curve that represented the Zonal Reserve Requirement.
    - Auction clearing prices were set where the supply curve intersected the vertical demand curve.
    - Under a vertical demand curve construct, supply beyond the Reserve Requirement did not clear the Auction.
    - MISO argues a downward sloping demand curve will better reflect the reliability value of incremental capacity.
- 2024/2025 Planning Reserve Auction (PRA) – Second seasonal capacity auction held in March 2024.
    - Compared to 2023/2024 (PRA):
        - Summer season capacity prices tripled to $30/MW-day.
        - Fall season capacity prices were steady at $15/MW-day.
        - Winter season capacity prices fell from $2.00/MW-day to $0.75/MW-day
        - Spring season capacity prices more than tripled to $34.10/MW-day.
        - Zone 5 fell short of its local clearing requirement in the fall and spring, capacity prices increased to $719.81/MW-day.[38]

2024/2025 Seasonal Capacity Auction

MISO is similarly challenged by the simultaneous retirement of dispatchable generation and the slow entry of new dispatchable generation to balance intermittent renewable generation. MISO held its second seasonal capacity auction, the 2024/2025 PRA, in March 2024 and highlighted these concerns. All zones except Zone 5 cleared with sufficient capacity, but capacity prices in summer and spring still increased significantly in all zones. Zone 5 failed to clear enough capacity to meet its local clearing requirement in the fall and spring by 872.4 MW and 196.4 MW, respectively. According to MISO's IMM, the shortage was "primarily attributable to the retirement of two large coal-fired resources at the end of the summer and long-duration planned outages in those shoulder seasons."[39] This resulted in capacity prices for those seasons to rise to the CONE of $719.81/MW-day.[40] The IMM went on to note that "winter prices dropped in the 2024–25 PRA to just $0.75 per MW-day, despite the high reliability risk from recent

[37] *Midcontinent Independent System Operator, Inc.*, Docket Nos. ER23-2977-000, ER23-2977-001, and ER23-2977-002, Order Accepting Tariff Revisions (FERC June 27, 2024), available at: https://elibrary.ferc.gov/eLibrary/filelist?accession_num=20240627-3010 (accessed Oct. 12, 2024).
[38] *See, e.g.,* MISO, "Planning Resource Auction: Results for Planning Year 2024-25" at 2 (Apr. 25, 2024, corrections posted Apr. 26, 2024), available at https://cdn.misoenergy.org/2024%20PRA%20Results%20Posting%2020240425632665.pdf (accessed Oct. 12, 2024).
[39] Potomac Economics, "2023 State of the Market Report for the MISO Electricity Markets" at 73 (June 2024), available at https://www.potomaceconomics.com/wp-content/uploads/2024/06/2023-MISO-SOM_Report_Body-Final.pdf (accessed Oct. 12, 2024).
[40] *Id.*

winter storms. This has largely been due to the growth in wind resources, even though having high levels of wind output during winter storms is not guaranteed."[41]

Overall, MISO noted concerning the 2024/2025 PRA results, "Capacity surplus across MISO eroded 30% in summer, primarily in the North/Central region,"[42] and, "Retirements, reduced imports and higher requirements are insufficiently offset by new capacity."[43] MISO went on to note, "Receding surplus, coupled with emerging risks due to fleet transition and new load additions, continue to pressure resource adequacy."[44]

Resource Adequacy Concerns

The North American Electric Reliability Corporation's ("NERC") 2023 Long-Term Reliability Assessment identified MISO identified as one of several grids that could see power supply shortfalls during normal peak operations.[45]

Later, in June 2024, an annual survey conducted by the Organization of MISO States ("OMS") and MISO indicated a growing capacity deficit beginning in the 2025/26 planning year.[46] OMS and MISO stated concerning the survey results, "Resource Adequacy risks could grow over time across all seasons, absent increased new capacity additions and actions to delay capacity retirements."[47]

Market Reforms

MISO and its IMM have stated capacity market reforms are urgently needed to address future resource adequacy concerns. The IMM has noted the vertical demand curve distorts economic signals and recommended a sloped demand curve instead:

> Unfortunately, MISO's capacity market has not been designed to send efficient price signals to spur the development of new dispatchable resources. Addressing this inefficiency requires MISO to correct the representation of demand by adopting a

[41] *Id.* at 74.
[42] MISO, "Planning Resource Auction Results for Planning Year 2024-25" at 2 (Apr. 25, 2024; corrections posted Apr. 26, 2024), available at https://cdn.misoenergy.org/2024%20PRA%20Results%20Posting%2020240425632665.pdf (accessed Oct. 12, 2024).
[43] *Id.*
[44] *Id.*
[45] NERC, "2023 Long-Term Reliability Assessment" at 6-7 (Dec. 2023), available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf (accessed Oct. 12, 2024).
[46] MISO, "OMS-MISO survey results indicate tight resource capacity in the upcoming planning year" (June 20, 2024), available at https://www.misoenergy.org/meet-miso/media-center/2024/oms-miso-survey-results-indicate-tight-resource-capacity-in-the-upcoming-planning-year/ (accessed Oct. 12, 2024).
[47] OMS and MISO, "2024 OMS-MISO Survey Results" (June 20, 2024, corrections posted June 20, 2024), available at https://cdn.misoenergy.org/20240620%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation635585.pdf (accessed Oct. 12, 2024).

reliability-based demand curve (RBDC). MISO has proposed an RBDC that would have raised summer capacity prices by five-fold to more than $50 per MW-day.[48]

MISO is set to replace the vertical demand curve with a new sloped demand curve in the 2025 planning year auction following a FERC approval in June 2024. MISO also has pending market reform proposals before FERC to adopt a new capacity accreditation methodology. A future FERC filing is also planned to propose reforms that will address the lengthy interconnection queue.

Conclusion

From the Companies' perspective, the continuing market reforms and redesigns, combined with the recent volatility in capacity prices, make it challenging at best to evaluate the implications of RTO membership for its customers. The Companies continuously monitor developments in both MISO and PJM in order to stay current on their issues in order to inform possible future actions that could impact the Companies' operations, even outside of RTO membership.

Section 4: CIFP Market Reform Impacts to Accredited Capacity

MISO is in the midst of filing for its own marginal capacity accreditation reforms. Due to the uncertainty around the final form of these tariff changes, the Companies focused on PJM's CIFP reforms, which FERC approved in January 2024. One of PJM's major reforms was implementing a capacity accreditation methodology known as marginal Effective Load Carrying Capability ("ELCC") to all generation resources. This methodology determines a resource class's marginal contribution to system reliability during historical loss-of-load hours when system reliability was strained.[49] If reliability declines during those hours as more capacity of a particular resource class is added to the system, the marginal ELCC class rating will be lower, and vice versa. Additionally, historical performance of a resource class during reliability-strained hours will also factor into the capacity rating. In other words, if a resource class experienced high forced outage rates during those loss-of-load hours, its ELCC ratings would be negatively impacted. The high level of correlated outages in PJM during Winter Storm Elliott in December 2022 was one of the driving motivations for thermal resource capacity accreditation reforms in the CIFP.

The adoption of this new capacity accreditation methodology had a sizable impact on the results of the 2025/2026 BRA because it was a significant departure from the previous accreditation methodology. Previously, only intermittent renewable resources were subject to a class average ELCC rating, not a marginal rating, to calculate their accredited capacity. Accredited capacity for thermal resources was different as well and calculated in the following way:

Installed Capacity (ICAP) * (1-Equivalent Demand Forced Outage Rate or EFORd)

[48] Potomac Economics, "2023 State of the Market Report for the MISO Electricity Markets" at 73 (June 2024), available at https://www.potomaceconomics.com/wp-content/uploads/2024/06/2023-MISO-SOM_Report_Body-Final.pdf (accessed Oct. 12, 2024).

[49] *See, e.g.,* PJM, "ELCC Education" at 25 (Feb. 16, 2024), available at: https://pjm.com/-/media/committees-groups/committees/pc/2024/20240216-special/elcc-education.ashx (accessed Oct. 12, 2024).

PJM defines EFORd as, "A measure of the probability that generating unit will not be available due to a forced outages or forced deratings when there is a demand on the unit to generate."[50] For context, PJM's pool-wide EFORd for the 2024/2025 delivery year was 5.02%.[51] For example, a proxy natural gas combined cycle unit with an installed capacity of 691 MW would be accredited with 656 MW of unforced capacity ("UCAP"), or approximately 95% of the unit's installed capacity, using the previous accreditation methodology.

The new marginal ELCC class ratings implemented for the first time in the 2025/2026 BRA saw broad reductions of capacity accreditation across most resource classes relative to the pre-CIFP accreditation methodology used in the 2024/2025 BRA, as shown for select resource classes in the table below.

PJM Capacity Accreditation Ratings Changes			
Resource Class	**2024/2025 BRA[52]**	**2025/2026 BRA[53]**	**Change**
Onshore Wind	21%	35%	14%
Offshore Wind	47%	60%	13%
Fixed-Tilt Solar	33%	9%	-24%
Tracking Solar	50%	14%	-36%
4-hr Storage	92%	59%	-33%
6-hr Storage	100%	67%	-33%
8-hr Storage	100%	68%	-32%
Nuclear	95%*	95%	0%
Coal	95%*	84%	-11%
Gas Combined Cycle	95%*	79%	-16%
Gas Combustion Turbine	95%*	62%	-33%
Gas Combustion Turbine Dual Fuel	95%*	79%	-16%
*Assuming pool-wide EFORd for the 2024/2025 delivery year of 5.02%			

The capacity accreditation reductions for natural gas and coal units specifically have an outsized effect due to their proportion of total generation supply in PJM. They have represented, on average, 46% and 23%, respectively, of cleared capacity in the five BRAs prior to the 2025/2026 auction.[54]

With respect to the 2025/2026 auction results, the impact of the new ELCC accreditation methodology was substantial. PJM estimated that approximately 28,064 MW of additional supply would have been

[50] PJM Glossary, available at: https://www.pjm.com/Glossary#:~:text=Equivalent%20Demand%20Forced%20Outage%20Rate,on%20the%20unit%20to%20generate (accessed Oct. 16, 2024).
[51] PJM, "2025/2026 RPM Base Residual Auction Planning Period Parameters" at 2, available at: https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-planning-period-parameters-for-base-residual-auction-pdf.ashx (accessed Oct. 12, 2024).
[52] PJM, "ELCC Class Ratings for 2024/2025," available at https://www.pjm.com/-/media/planning/res-adeq/elcc/elcc-class-ratings-for-2024-2025.ashx (accessed Oct. 12, 2024).
[53] PJM, "ELCC Class Ratings for the 2025/2026 Base Residual Auction," available at: https://www.pjm.com/-/media/planning/res-adeq/elcc/2025-26-bra-elcc-class-ratings.ashx (accessed Oct. 12, 2024).
[54] *See* PJM spreadsheet available at: https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/rpm-commitment-by-fuel-type-by-dy.ashx (accessed Oct. 16, 2024).

accredited in the 2025/2026 auction using the pre-CIFP capacity accreditation rules.[55] PJM's IMM estimated that the new ELCC approach increased total auction capacity costs by 49.1%, or $4.4 billion compared to the pre-CIFP accreditation methodology.[56] S&P Commodity Insights forecasts PJM's reserve margin will fall to as low as 6.8% in 2025 due to the capacity accreditation reforms and slow build-out of new generation.[57]

New RTO Capacity Accreditation Methods Significantly Impair any Capacity "Benefit" the Companies Might Have Realized

Past RTO studies have generally shown that the Companies could reduce their need for capacity by RTO membership due to the way in which RTOs calculate members' capacity responsibility relative to their load. Furthermore, the reduced capacity need often created a near-term revenue opportunity until the "excess" capacity (from an RTO perspective) was retired. However, the recent changes in market rules and capacity accreditation have flipped the analysis. Using the new tariff, the Companies would actually have less accredited capacity in PJM and MISO than they do as a standalone utility outside an RTO.

PJM

To demonstrate this, the Companies assessed the impact of the new PJM capacity accreditation methodology on two versions of their capacity position: a backward look at the most recent excess capacity analysis in the 2022 RTO Analysis and a forward-looking analysis including an updated load forecast and future resource mix.

The 2022 RTO Analysis showed favorability in the early years of the analysis for capacity sales in an environment with low capacity auction prices. This analysis used PJM's pre-CIFP capacity accreditation methodology, which provided higher UCAP accreditation and resulted in ample room for near-term capacity sales. But applying the 2026/2027 BRA capacity accreditation methodology and holding all else constant from the 2022 RTO analysis produces a very different result: UCAP levels fall markedly and the excess capacity available to sell disappears, as indicated in the table below for capacity year 2024/2025 as a proxy.

2024/2025 Capacity Year					
Pre-CIFP Accreditation (2022 RTO Study)			**Post-CIFP 2026/2027 BRA Accreditation**		
ICAP	**UCAP**	**Long/(Short)**	**ICAP**	**UCAP**	**Long/(Short)**
7,924 MW	7,154 MW	127 MW	7,924 MW	5,938 MW	(973 MW)

[55] PJM, "2025/2026 Base Residual Auction Results" at 26 (Aug. 21, 2024), available at: https://www.pjm.com/-/media/committees-groups/committees/mrc/2024/20240821/20240821-item-08---2025-2026-base-residual-auction---presentation.ashx (accessed Oct. 12, 2024).
[56] Monitoring Analytics, "Analysis of the 2025/2026 RPM Base Residual Auction, Part A" at 1 (Sept. 20, 2024), available at: https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_A_20240920.pdf (accessed Oct. 12, 2024).
[57] https://www.capitaliq.spglobal.com/apisv3/spg-webplatform-core/news/article?id=83514230&KeyProductLinkType=58&utm_source=MIAlerts&utm_medium=scheduled-news&utm_campaign=Alert_Email

With respect to the forward assessment, the Companies' current load forecast was incorporated with the expected resource mix for 2028. In that year, the Companies assume their fleet installed capacity will be 8,256 MW, resulting in unforced capacity of 6,243 MW after applying PJM's post-CIFP accreditation ratings for the 2026/2027 BRA. Assuming all resources clear 100% of their capacity as seen in the 2025/2026 BRA, the UCAP position results in a capacity deficit of 787 MW relative to the 2028 peak load forecast of 7,030 MW. However, if the Companies were to consider the Fixed Resource Requirement ("FRR") Alternative, the unforced capacity obligation is estimated to be 6,585 MW, still leaving the Companies' UCAP position at a deficit of approximately 342 MW. This seemingly removes the FRR Alternative from consideration and would require the Companies to resolve any capacity deficit as a full Reliability Pricing Model ("RPM") market participant:

> Failure to commit the required resources would result in FRR Commitment Insufficiency Charge and ineligibility to continue the FRR Alternative. An FRR Capacity Plan is the long-term plan for the commitment of Capacity Resources to satisfy the daily zonal unforced capacity obligations of an LSE that has elected the FRR Alternative in an FRR Service Area….[58]

MISO

Given the uncertainty around the final form of MISO's marginal capacity accreditation reform proposal currently before FERC, MISO's 2024/2025 PRA Seasonal Accredited Capacity ("SAC") methodology was used to provide an indicative estimation of the Companies' capacity position in 2028 from MISO's perspective. The SAC methodology was approved by FERC on August 31, 2022. Under this market reform, class average capacity accreditation and ELCC continued to apply to solar and wind resources, respectively, but on a seasonal basis instead of an annual basis following MISO's shift to a seasonal capacity auction construct.[59] Additionally, thermal resources were subject to a new seasonal availability-based accreditation that sought to account more accurately for correlated outages.[60]

Applying these accreditation factors to the Companies' assumed 2028 generating fleet produces a UCAP of 6,565 MW. This results in a 465 MW annual deficit to the Companies' 2028 peak load forecast of 7,030 MW for the 2028 base year. The Companies' total obligation would also include a seasonal Reserve Margin and transmission losses on top of the peak demand.[61] The annual deficit value also does not contemplate the seasonal allocation of this deficit, which may have capacity procurement cost implications involved with remedying any shortfall to the seasonal Reserve Requirements.

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[58] PJM, "PJM Manual 18: PJM Capacity Market, Revision 59" at 215 (June 27, 2024), available at: https://www.pjm.com/-/media/documents/manuals/m18.ashx (accessed Oct. 16, 2024).

[59] MISO, "Planning Year 2024-2025: Wind and Solar Capacity Credit Report" (Mar. 2024), available at: https://cdn.misoenergy.org/Wind%20and%20Solar%20Capacity%20Credit%20Report%20PY%202024-2025632351.pdf (accessed Oct. 12, 2024).

[60] MISO, "Planning Year 2024-2025: Schedule 53 Class Averages" (Feb. 20, 2024), available at: https://cdn.misoenergy.org/PY%202024-2025%20Schedule%2053%20Class%20Average631181.pdf (accessed Oct. 12, 2024).

[61] MISO Resource Adequacy Subcommittee, "Planning Reserve Margin Requirement (PRMR) Allocation" at 4-5 (Oct. 9, 2024), available at: https://cdn.misoenergy.org/20241009%20RASC%20Item%2009%20PRMR%20Allocation651953.pdf (accessed Oct. 12, 2024).

Section 5: PJM and MISO Express Reliability Concerns Regarding EPA's Recent Greenhouse Gas Rules

One concern among many that electric utilities have expressed regarding the EPA's recent final Greenhouse Gas Rules is that the regulations will jeopardize grid reliability. PJM and MISO are so concerned that they joined with ERCOT and SPP to file a joint *Amicus* brief opposing the regulations. In it, the grid operators stated:

> The Final Rule unreasonably discounts that existing fossil power generators will need to decide whether to commit to installing untested technology or retire the generating unit years before the compliance deadline, given the economic cost and risk of compliance. As a result, decisions to retire units before the end of their useful life may be accelerated because of the Final Rule. The Joint ISOs/RTOs are concerned that premature retirements of generating units that provide critical reliability attributes can have significant, negative consequences on reliability.[62]

In support of their position, the grid operators made the follow arguments:

- "EPA did not adequately analyze or adopt proposed adjustments to the Rule to mitigate potential reliability impacts."[63]
    - "EPA has not adequately analyzed resource adequacy and reliability impacts in the Final Rule. Congress explicitly required consideration of resource adequacy and reliability impacts by providing in Section 111 that EPA consider 'energy requirements' in establishing its regulatory program under this section. 42 U.S.C. § 7411(a). By including that requirement, Congress clearly required EPA to do more than simply look at environmental issues in a vacuum without considering the larger energy requirements of the grid."[64]
- "EPA has not adequately considered resource adequacy and reliability impacts as part of its responsibility to consider "energy requirements" in conjunction with other proposed, pending, or existing regulations."[65]
    - "The impact of the Final Rule must also be considered in conjunction with the numerous other proposed, pending, or existing environmental regulations that impact grid reliability and resource adequacy—all of which are resulting in a decline in reserve margin and premature retirement of dispatchable 'baseload' resources (i.e., resources most currently in the form of coal and natural gas)."[66]
- "The Final Rule doesn't allow enough compliance flexibility to mitigate short-term grid emergencies."[67]

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[62] *West Virginia v. EPA*, D.C. Cir. Docket No. 24-1120, Brief of Midcontinent Independent System Operator, Inc., PJM Interconnection L.L.C., Southwest Power Pool, Inc., and Electric Reliability Council of Texas, Inc., as *Amici Curiae* in Support of Petitioners at 1 (Sept. 13, 2024), available at: https://www.pjm.com/-/media/documents/other-fed-state/20240913-24-1120.ashx (accessed Oct. 12, 2024).
[63] *Id.* at 10.
[64] *Id.*
[65] *Id.* at 17.
[66] *Id.* at 17-18.
[67] *Id.* at 24.

- “The Final Rule is too constraining to address reliability impacts resulting from the compliance strictures of the Rule by making the declaration of an EEA2 emergency a condition precedent to a unit owner availing itself of short-term compliance relief from the Rule’s requirements.”[68]

Regarding the viability of complying with the Greenhouse Gas Rules through carbon capture and sequestration (“CCS”) technology, the grid operators stated: “None of EPA’s projected timeframes reflect historical rates of adoption of CCS technology for electrical generation purposes, nor does EPA adequately consider the risks that the technologies will not mature in time for [electric generating unit] owners to deploy them.”[69]

Section 6: Continued uncertainty and cost attributable to transmission expansion cost within the RTOs

Transmission planning and the allocation of transmission expansion cost are major activities for each RTO. Under current PJM policy, the cost of new high voltage transmission projects approved under its annual Regional Transmission Expansion Planning (“RTEP”) process is allocated based on a combination of zonal load ratio share and flow-based calculations. These charges are recovered under Schedule 12 of the PJM tariff. In MISO, these type of high voltage projects are currently recovered via Schedule 26A of the MISO tariff, which are allocated to all withdrawals of energy from the market on a per-MWh basis. MISO’s Board of Directors has already approved $10.3 billion in projects in “Tranche 1” and is expected to approve nearly $22 billion in additional projects in “Tranche 2” later this year. These projects alone could add hundreds of millions of dollars of cost to the Companies if they joined MISO.

Section 7: Continued uncertainty and reliability concerns in RTOs impair ability for modeling to inform Companies’ RTO decision.

The current state of flux in MISO and PJM market designs, rules, and tariffs make it difficult to reliably and confidently model the financial implications of future RTO membership. At the time the 2024 RTO Membership Analysis was prepared, it was hoped that the RTOs would make significant progress in addressing their resource adequacy issues, thus enabling a comprehensive modelling exercise of the Companies’ generation and load as members of both MISO and PJM. However, the market rules in each RTO continue to evolve, and when combined with the large uncertainty created by EPA’s final Greenhouse Gas Rules, it is not practical to perform any meaningful modelling of MISO and PJM that would provide definitive insights to inform a decision to join either RTO.

Nonetheless, the Companies continue to monitor the market design activity of each RTO, the results of their capacity auctions, and their various reports regarding future resource adequacy. As the Companies have stated on numerous occasions, they are not opposed to RTO membership, but because it is likely a one-way option, exercising that option should only be done when it is clearly in the best long-term interest of customers.

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[68] *Id.* at 26-27.
[69] *Id.* at 7.

Section 8: Update on SEEM Activities

The Southeast Energy Exchange Market ("SEEM") has been operational for almost two years, and it has been beneficial for the Companies' customers.[70] From January 2023 through June 2024, the Companies have sold 38,641 MWh at an average price of $44.20/MWh and purchased 51,045 MWh at an average price of $12.62/MWh. The Companies have been active SEEM participants, accounting for 7.5% of total SEEM transactions over this period. The resulting off-system sales margins and power purchase savings have benefited customers through the Companies' Fuel Adjustment Clause mechanisms. Indeed, the Companies estimate that customers have benefited by approximately $1,075,000 from sales and purchases in 2023 and the first two quarters of 2024, which is over *eight times* the estimated cost of SEEM participation during that period ($127,000).[71]

The Companies seek to participate in every 15-minute market and have a systematic process that determines the Companies' incremental costs and volume available for sale and the decremental costs and volumes for purchase. This process is similar to that used for making "over-the counter" off-system sales and purchases from MISO, PJM, and TVA. See Appendix 8 for a detailed description of the Companies' SEEM bid and offer process.

Finally, it is important to note that while SEEM continues to operate, the U.S. Court of Appeals for the District of Columbia ("D.C. Circuit") remanded orders approving SEEM back to FERC. Only FERC can change open access transmission tariff rates related to SEEM's operations. Thus, the D.C. Circuit's decision did not immediately affect SEEM's operations. The intervening entities who challenged SEEM have filed an additional appeal based on the passage of time on remand without an order from FERC. At present, the parties are actively litigating at the D.C. Circuit but have also briefed the issues associated with the SEEM remand proceedings at FERC. Due to the status of the ongoing litigation on SEEM in both venues, it is not possible to identify the potential impacts to the ongoing operation of SEEM. However, the Companies will continue to monitor SEEM developments and seek to use their SEEM membership to customers' benefit whenever and as long as possible.

Section 9: De-pancaking Litigation Update

The Companies currently provide merger mitigation de-pancaking ("MMD") credits to certain entities importing from MISO under Rate Schedule 525 currently on file with FERC. The Companies had been crediting MISO transmission charges for imports from MISO for certain customers pursuant to a FERC filed agreement, LG&E/KU FERC First Revised Rate Schedule No. 402, relating to the Companies' 1998 merger and 2006 exit from MISO.[72] The Companies received FERC approval to eliminate MMD subject to the implementation of a transition mechanism for certain power supply arrangements.[73] A decision from the D.C. Circuit Court of Appeals largely affirmed FERC's analysis in the 2019 Removal Order, but it ultimately

[70] See [Southeast Energy Exchange Market (southeastenergymarket.com)](southeastenergymarket.com) for more information on SEEM and Appendix 7 for August 2024 audit report.
[71] See Appendix 7 for the most recent SEEM Independent Market Monitor monthly report, which provides various SEEM market data.
[72] *See E.ON U.S., LLC, et al.*, FERC Docket No. ER06-1279-000.
[73] *Louisville Gas & Elec. Co.*, 166 FERC ¶ 61,206 ("2019 Removal Order"), *order on reh'g & clarification*, 168 FERC ¶ 61,152 (2019), *aff'd sub nom. Ky. Mun. Energy Agency v. FERC*, 45 F.4th 162 (D.C. Cir. 2022) ("KYMEA").

vacated the decision and remanded the matter back to FERC.[74] In its order on remand, FERC reversed its decision allowing for the termination of MMD and required the Companies to reinstitute the MMD provisions of Rate Schedule 402.[75] The Companies complied with this directive by filing Rate Schedule 525. The Companies appealed FERC's orders on remand and the compliance filing to the D.C. Circuit Court of Appeals. Due to the status of the ongoing litigation on MMD, it is not possible to identify how the Companies' MMD obligation might be impacted by RTO membership or to quantify such hypothetical impact. The Companies will revisit the potential impact of and to MMD in performing the next RTO analysis.

<u>Section 10: Conclusion</u>

The Companies continue to be open to possible future RTO membership. The Companies are actively monitoring market developments in MISO and PJM to help inform their analysis and future decisions. However, given the uncertainty in RTO market design, resource adequacy, and EPA's Greenhouse Gas Rules, it is clear that RTO membership at this time would introduce significant unquantifiable risks for the Companies' customers without a clear quantification of possible benefits.

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[74] The D.C. Circuit stated, "In short, the Commission's conclusion that sufficient competition would continue after [MMD] was based on substantial evidence from which it drew sensible inferences employing its expert knowledge of electricity markets. That is the 'kind of reasonable agency prediction to which we ordinarily defer.'" However, the D.C. Circuit faulted FERC for failing to evaluate the impact of the removal of MMD on rates and vacated the decision. *KYMEA,* 45 F.4th at 177.

[75] *Louisville Gas & Elec. Co.*, 183 FERC ¶ 61,122 (2023).

APPENDICES

Appendix 1 – PJM Regional Transmission Expansion Plan, March 7, 2024

Appendix 2 - Energy Transition in PJM: Flexibility for the Future, June 24, 2024

Appendix 3 – MISO’s Response to the Reliability Imperative, February 2024

Appendix 4 – Attributes Roadmap – MISO, December 2023

Appendix 5 – 2024 OMS-MISO Survey Results, June 20, 2024

Appendix 6 – Queued Up: 2024 Edition - Lawrence Berkeley National Laboratory, April 2024

Appendix 7 - SEEM Audit Report prepared by Potomac Economics, August 2024

Appendix 8 - Companies’ SEEM Bid/Offer Process, July 2023

Appendix 9 – DC Circuit Court of Appeals Case No. 24-1120 – PJM, MISO, SPP, ERCOT Amicus Curiae Brief

Appendix 10 - It’s Time to Reconsider Single-Clearing Price Mechanisms in U.S. Energy Markets - Energy Law Review, May 2, 2023

Appendix 11 - Resource Accreditation White Paper V 2.1 – MISO, March 2024

Appendix 12 – PJM ELCC Education – February 2024