COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC INVESTIGATION OF THE	)	
SERVICE, RATES AND FACILITIES OF	)	Case No. 2021-00370
KENTUCKY POWER COMPANY	)	

KENTUCKY POWER COMPANY'S RESPONSE TO SHOW CAUSE ORDER

Kentucky Power Company ("Kentucky Power" or the "Company") provides this response to the Public Service Commission of Kentucky's ("Commission") June 23, 2023 Order requiring the Company to "show cause why it should not be subject to the remedy for failure to provide adequate service in its service territory under KRS 278.018(3) and why it should not be subject to an assessment of civil penalties under KRS 278.990 for Kentucky Power's alleged violation of KRS 278.030" ("Show Cause Order").

With respect to KRS 289.018(3), the Show Cause Order is based on the incorrect premise that Kentucky Power has failed to provide adequate service. Kentucky Power provides and will continue to provide adequate service to its customers. KRS 278.018(3) provides for remedies in the event a utility fails to render "adequate service." Adequate service is, in turn, defined as follows:

> "Adequate service" means having sufficient capacity to meet the maximum estimated requirements of the customer to be served during the year following the commencement of permanent service and to meet the maximum estimated requirements of other actual customers to be supplied from the same lines or facilities during such year and to assure such customers of reasonable continuity of service[.][1]

[1] KRS 278.010(14).

Through the combination of its owned generation, contracted capacity resources, and its managed participation in the PJM Interconnection, L.L.C. ("PJM") energy market, Kentucky Power is able to meet its customers' "maximum estimated requirements" and provide its customers with "reasonable continuity of service." In fact, during Winter Storm Elliott, extraordinary weather conditions drove the Company's demand to a level 46% higher than the Company's previous 12-month average peak demand.[2] Yet the Company nevertheless was able to provide service without load shedding. Kentucky Power's resources provided continuity of service for requirements far greater than the estimated maximum.

With respect to KRS 278.030, subsection (2) requires that a utility "furnish adequate, efficient and reasonable service…"[3] According to the Show Cause Order, to satisfy that requirement, a utility must have "[s]ufficient generation capacity that can be used to serve the entirety of native demand" to "act[] as a physical hedge to market energy prices;" "without adequate generation capacity, Kentucky Power and its customers are subject to higher prices from market purchases for at least the amount the utility is short of its native demand."[4] That position ignores the benefits provided by the Company's combination of owned and market resources and incorrectly assumes that customers are always better off if they are completely hedged against market prices. In addition to prudently maintaining its generation facilities so they are ready to serve customers when they are cost effective, Kentucky Power actively evaluates its market exposure and, based on market conditions, determines whether to enter into forward energy purchases or to rely on the spot market for energy. Because of market conditions in 2022, including very high gas prices that resulted in high forward energy prices, the Company

[2] Affidavit of Alex E. Vaughan, attached hereto as Exhibit A ("Vaughan Affidavit") at ¶ 19.

[3] KRS 278.030(2).

[4] Show Cause Order at 5.

determined that customers would be better off, and would pay less, if the Company satisfied some portion of their demand through the energy spot market. That decision was prudent. Indeed, despite the high energy spot market prices during Winter Storm Elliott, customers were still on the whole *better off, and paid less,* than if Kentucky Power had fully hedged for the winter.

Thus, Kentucky Power provides adequate service as defined in KRS 278.010(14) and also provides adequate, efficient, and reasonable service as required by KRS 278.030(2). Accordingly, the remedies referenced in the Show Cause Order are inappropriate. The Show Cause Order and the proceeding proposed therein should be dismissed.

I. Factual Background

A. Kentucky Power's Capacity Obligation

On December 8, 2022, the Rockport Unit Power Agreement ("Rockport UPA"), under which the Company was entitled to a 15% share of the capacity and energy from the Rockport coal-fired generation facility in Indiana, terminated.[5] Kentucky Power's share of the capacity from the Rockport plant was 393 MW, and at the time the Rockport UPA terminated, the Company's owned or contracted-for capacity had been approximately 200 MW greater than its estimated and recent historic requirements.[6] As a result of declining load and its ability to rely on the PJM market, the Company elected not to renew the agreement.[7] The decision to not renew the Rockport UPA significantly reduced the cost of serving Kentucky Power's customers without any impairment to the Company's ability to provide reliable service.

Following the termination of the Rockport UPA, the Company right-sized its capacity position by purchasing capacity from the AEP Operating Companies that it would use to satisfy

---

[5] Vaughan Affidavit at ¶ 6.

[6] *Id*.

[7] *Id*.

its capacity obligations under Power Coordination Agreement ("PCA").[8] Specifically, the Company acquired 152 MW of capacity for the remainder of the 2022/23 Planning Year and forecasts that it will require 65 MW of capacity through the PJM 2023/2024 Planning Year ending May 31, 2024.[9]

Kentucky Power secures capacity in a quantity sufficient to meet its reliability requirement under PJM's capacity construct.[10] This provides significant financial benefits to customers. That is because PJM is a summer peaking Regional Transmission Organization ("RTO"), and the capacity commitments that load-serving entities must meet are based on their summer peaks.[11] But Kentucky Power is a winter peaking utility.[12] PJM's summer peaking construct thus means that Kentucky Power customers can meet their reliability requirement with less capacity than they would need if the reliability requirement were based on the winter peak. These customer savings do not come at the expense of reliability. Because PJM secures an annual capacity product, and does so in a quantity sufficient to meet the RTO's higher summer peak, the RTO has more than sufficient capacity (and energy) available to meet the RTO's winter peak—including Kentucky Power's.[13] This results in financial benefits to Kentucky Power customers and customers of other winter-peaking utilities.

---

[8] The PCA is a tariff agreement on file with the Federal Energy Regulatory Commission among Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, and Wheeling Power Company (the "AEP Operating Companies"). Under the PCA, Kentucky Power and the other AEP Operating Companies participate in a joint Fixed Resource Requirement plan to satisfy their collective resource adequacy obligations to PJM. PJM is the balancing authority to which the Company belongs. It implements a resource adequacy construct approved by the Federal Energy Regulatory Commission designed to ensure sufficient capacity to meet peak load throughout the 13-state PJM footprint.

[9] Vaughan Affidavit at ¶ 6.

[10] *Id* at ¶¶ 4-5.

[11] *Id* at ¶ 7.

[12] *Id*.

[13] *Id*.

B. <u>Kentucky Power's Approach to Market Purchases of Energy</u>

As a member of PJM, the Company offers 100% of its generation output (energy) from its owned and contracted-for resources into the PJM market and acquires 100% of its energy requirements from the PJM market.[14] From a financial point of view, Kentucky Power's customers benefit from this construct directly: it enables efficiencies in the regional generation portfolio to be available to Kentucky Power's customers through its membership in PJM, lowering the cost of the energy required to serve them.[15]

From a power supply reliability point of view, Kentucky Power's customers receive the benefit of Kentucky Power's diverse power supply (combining resources available through its membership in PJM, contracts with other parties, and its owned generation).[16] The capacity available from Kentucky Power's owned generation assets (a 50 percent undivided interest in the coal-fired Mitchell Generation Station and the natural gas-fired Big Sandy Unit 1 Generating Station) is sufficient in most circumstances in effect to provide the energy required to serve Kentucky Power's customers.[17] Kentucky Power prudently manages the maintenance of its owned-generation portfolio to maximize the long-term benefits of the assets for the Company's customers.[18] However, because of outage schedules and the relative cost (compared to spot market prices) of those assets, Kentucky Power also relies directly on the PJM energy market to provide

---

[14] *Id* at ¶ 9.

[15] *Id*.

[16] *Id* at ¶ 7.

[17] *Id* at ¶ 10.

[18] Affidavit of Timothy C. Kerns, attached hereto as Exhibit B ("Kerns Affidavit") at ¶ 20.

energy for its customers.[19] This approach is consistent with the plan identified in the Company's 2019 Integrated Resource Plan ("IRP").[20]

The Company made the decision to rely on the PJM market and its large, multi-state power pool to meet a portion of its energy needs because doing so is better for customers than if Kentucky Power itself owned or contracted for all the generation that it might need.[21] Procuring a complete physical hedge to effectively insulate Kentucky Power from market energy prices—that is, owning or contracting for all generation capacity—would be more expensive than buying energy on the PJM spot market during times of low market energy prices, such as those that have existed for most of the last 15 years.[22] Therefore, the Company's plan for covering load obligations in excess of owned or contracted-for generation supply has for years been, and continues to be, to purchase the balance of its energy requirements from the PJM spot energy markets.[23]

C. <u>Kentucky Power's Market Purchase Strategy for the Winter of 2022/2023</u>

Previously, the Rockport UPA provided Kentucky Power with a physical hedge against energy spot prices. By contrast, the short-term capacity the Company acquired following the termination of the Rockport UPA does not give Kentucky Power access to the energy produced from the projects providing capacity to the Company. As explained below, the Company decided to rely on the PJM spot market, and not to procure physical or financial hedges beyond its existing Big Sandy and Mitchell plants. Based on all available information at the time, and looking back

[19] Vaughan Affidavit at ¶ 10.

[20] *Id* at ¶¶ 14-15.

[21] *Id* at ¶ 11.

[22] *Id*.

[23] *Id*.

at what actually transpired, the latter approach would have been significantly more expensive for customers.

To mitigate exposure to spot energy market prices, the Company can hedge through forward power purchases.[24] Although it is not possible to perfectly predict future energy prices, making forward power purchases over a period of time can generally help reduce exposure to spot market energy price volatility.[25] But forward purchases come with a cost and leave customers at risk of paying more than the spot market if electricity prices turn out to be lower than the forward price.[26] Thus, forward purchases must be used with due care, taking into account the available information to determine if they are likely to be beneficial.

In anticipation of the termination of the Rockport UPA, over the course of 2022, Company personnel and subject matter experts within the AEP Service Corporation met monthly to develop a strategy to optimize the Company's market purchase strategy.[27] During that time, natural gas prices rose to unprecedented levels as the result of global factors, including high demand for U.S. liquified natural gas, the war in Ukraine, and the transition out of the COVID-19 pandemic, all of which caused extreme volatility related to natural gas demand and production.[28] These increases in natural gas prices resulted in historically high forward energy prices.[29] Because the forward energy prices so far exceeded historical energy prices, creating the significant potential that actual

---

[24] *Id* at ¶ 28.

[25] *Id*.

[26] *Id*.

[27] *Id* at ¶ 27.

[28] *Id* at ¶ 29.

[29] *Id*.

market prices would be lower than the forward prices, the Company elected not to enter into any forward energy purchases for the winter of 2022-2023 in advance of that period.[30]

This decision was prudent at the time, and in fact resulted in economic benefits to customers.[31] Despite Winter Storm Elliott, over the course of 2022, forward power purchases to hedge against market prices would not have resulted in a more economical outcome compared to the strategy that the Company deployed.[32] Thus, the Company's forward-looking energy procurement strategy was prudent based on all available information at the time, and its sound judgment was in fact confirmed by actual energy prices during the 2022/23 winter season.

The table below shows the costs the Company would have incurred by entering forward energy contracts for the December 2022 through March 2023 time period in an amount sufficient to replace the Rockport UPA (96 MW),[33] and compares those costs to the average liquidated (that is, actual) energy market price in each of those months. For example, in July, the Company could have entered into a forward energy purchase for energy produced in January at an average price of \$113.72/MWh. The actual average liquidated price for January 2023 was \$36.22/MWh. If the Company had entered into a forward energy purchase of 96 MW in July for January energy, the Company's purchased power expense for that month would have been \$5,518,062 higher than what spot market settlements produced. If the Company had entered into a forward energy

[30] *Id*.

[31] *Id* at ¶ 30.

[32] *Id*.

[33] *Id* at ¶ 31. 96 MW is the simple average of the short-term capacity purchased to meet Kentucky Power's reliability requirement following the Rockport UPA's termination, for the planning years 2022/23 through 2025/26. The Prices identified in the chart reflect prices at the AEP Dayton Hub which is a liquid trading hub where potential hedges would have settled. Although this is not the point where Kentucky Power's load settles, there is no material amount of basis difference between the two points.

purchase of 96 MW in July for the entire winter season, the Company's purchased power expense would have been $14,263,151 higher than the actual spot market results.

MW of Purchased Power Comensurate with RP UPA Replacement Capacity	96				
July Forwards	**December**	**January**	**February**	**March**	**Total**
Forward Price	$87.96	$113.72	$106.52	$76.42	
Liquidated Price	$83.85	$36.22	$27.81	$28.80	
Increase in Purchase Power Exp	**$292,635**	**$5,518,062**	**$5,061,872**	**$3,390,582**	**$14,263,151**
August Forwards	**December**	**January**	**February**	**March**	**Total**
Forward Price	$108.04	$136.92	$126.07	$78.07	
Liquidated Price	$83.85	$36.22	$27.81	$28.80	
Increase in Purchase Power Exp	**$1,722,347**	**$7,169,921**	**$6,319,140**	**$3,508,063**	**$18,719,471**
September Forwards	**December**	**January**	**February**	**March**	**Total**
Forward Price	$94.97	$126.51	$111.50	$75.71	
Liquidated Price	$83.85	$36.22	$27.81	$28.80	
Increase in Purchase Power Exp	**$791,753**	**$6,428,720**	**$5,382,137**	**$3,340,030**	**$15,942,640**
October Forwards	**December**	**January**	**February**	**March**	**Total**
Forward Price	$73.45	$106.30	$91.27	$67.17	
Liquidated Price	$83.85	$36.22	$27.81	$28.80	
Increase in Purchase Power Exp	**($740,488)**	**$4,989,752**	**$4,081,138**	**$2,731,975**	**$11,062,376**
November Forwards	**December**	**January**	**February**	**March**	**Total**
Forward Price	$80.90	$99.41	$91.97	$67.02	
Liquidated Price	$83.85	$36.22	$27.81	$28.80	
Increase in Purchase Power Exp	**($210,042)**	**$4,499,179**	**$4,126,155**	**$2,721,295**	**$11,136,586**

The chart above shows that if Kentucky Power had purchased forward power for the winter season to replace the Rockport UPA, it would have spent millions of dollars more than customers in fact actually paid in energy market purchases. Indeed, for 96 MW of purchased forward power, customers would have paid between $11 million and nearly $19 million more than they actually paid for those 96 MW, depending on when Kentucky Power entered into the forward contracts.

D. Winter Storm Elliott

Winter Storm Elliott occurred December 23, 2022 through December 26, 2022, in the PJM region (the "Winter Storm Elliott Period").[34] The storm was an extreme cold weather event that caused record cold temperatures across much of the United States, including one of the most extreme temperature drops in PJM's history.[35] The resulting load during the Winter Storm Elliott Period was an extreme outlier in both magnitude and timing. According to PJM, the Christmas Eve peak load was 10 gigawatts higher than the forecast, and the Christmas Eve valley was higher than any Christmas Eve *peak* over the last 10 years, and approximately 40 gigawatts higher than the next highest Christmas Eve valley over the last 10 years.[36] PJM reported that unplanned generator outages were substantially higher during this period as compared to prior years: while the peak outage rate for the winters of 2021/22 and 2020/21 was 7.6% and 7.9%, respectively, the peak outage rate of the PJM fleet during Winter Storm Elliott reached 24%, which also surpassed the 2014 Polar Vortex forced outage rate of 22%.[37] Outages by gas-fired generators represented the largest share of forced outage increases during Winter Storm Elliott.[38]

The Company's own peak load during the Winter Storm Elliott Period was 1,358 MW, 46% higher than the Company's previous 12-month average peak demand ("12CP") of 929 MW.[39] In 85 of the 96 hours during the event, the Company's hourly average load was higher than its

---

[34] *Id* at ¶ 19.

[35] PJM Interconnection, L.L.C., *Winter Storm Elliott: Event Analysis and Recommendation Report* (July 17, 2023), at 40-41, *available at* https://www.pjm.com/-/media/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.ashx ("PJM Winter Storm Elliott Report"). A copy of the PJM Winter Storm Elliott Report is attached hereto as Exhibit C.

[36] *Id.* at 38-39.

[37] *Id*. at 49.

[38] *Id.*

[39] Vaughan Affidavit at ¶ 19.

most recent 12CP demand.[40] The energy consumption in the Kentucky Power service territory during the Winter Storm Elliott Period totaled 107,356 MWh, compared to 60,275 MWh during the same period a year earlier, an increase of 47,081 MWh.[41]

The drastic temperature drop and higher than forecasted load caused PJM to dispatch generation reserves, many of which failed to perform. Generation resource outages during Winter Storm Elliott peaked at approximately 47,000 MW.[42] In contrast, although Kentucky Power's Big Sandy Plant remained on a maintenance outage, the Mitchell Plant performed at levels in excess of PJM fleet averages.[43] Despite these challenges, PJM did not shed load due to a power supply-related outage, and the lights and heat stayed on in Kentucky Power's service territory. By contrast, several neighboring systems—including in Kentucky—shed load during the storm, and relied on transmissions from the PJM system to avoid even greater load shed.[44]

As discussed above, if the Company had purchased 96 MW of forward power for the winter period, rather than relying on the energy market, customer costs for the winter would have been between $11 million and $19 million higher than they were. If the Company had additionally purchased the forward power needed to meet the unanticipated Winter Storm Elliott peak,

---

[40] *Id.*

[41] *Id.*

[42] PJM Winter Storm Elliott Report at 49.

[43] Kerns Affidavit at ¶ 8.

[44] *See, e.g.*, PJM Winter Storm Elliott Report at 46-68; Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Responses to Follow-up Data Requests from the Companies' January 3, 2023 Briefing on Winter Storm Elliott, Docket No. M-100, Sub 163 (N.C. Utils. Comm'n Jan. 9, 2023), https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=834abfc0- 001c-421d-b96b-8c73eb8cccb4; Tennessee Valley Authority, TVA Accepts Full Responsibility, Starts Full Review (Dec. 28, 2022), https://www.tva.com/newsroom/press-releases/tva-accepts-responsibility-starts-full-review; Ryan Van Velzer, LG&E/KU Underestimated Energy Demand Ahead of Winter Storm Elliott, Louisville Public Media (Jan. 26, 2023), https://www.lpm.org/news/2023-01-26/lg-e-ku-underestimated-energy-demand-ahead-of-winter-storm-elliott.

customer costs for the winter would have been higher still—tens of millions of dollars higher. Based on the data above, the only way a hypothetical purchased power transaction would have potentially benefitted the Company's customers is if the Company had been able to predict that Winter Storm Elliott would hit in December, but not in January, February, or March, and so had hedged *only* for December—and even then only if the Company had purchased its hedges in October or November, rather than earlier in the year.[45]

II. Argument

A. Kentucky Power Satisfies the Adequate Service Standard in Kentucky.

Kentucky law is explicit as to the obligation of Kentucky Power to provide adequate service to its customers. The Kentucky legislature has defined adequate service in unequivocal terms:

> "Adequate service" means having sufficient capacity to meet the maximum estimated requirements of the customer to be served during the year following the commencement of permanent service and to meet the maximum estimated requirements of other actual customers to be supplied from the same lines or facilities during such year and to assure such customers of reasonable continuity of service[.][46]

Through its combination of owned generation resources, contracted-for capacity resources, and managed participation in the PJM market, Kentucky Power owns and contracts for sufficient capacity to meet the maximum estimated demand of its customers, and it has access to capacity and energy sufficient to provide reliable and reasonable electric service to its customers.

The fact that Kentucky Power did not experience any power supply outages during Winter Storm Elliott is dispositive. Kentucky Power cannot be found to have violated its obligation to provide adequate service when even in the most extraordinary of circumstances Kentucky Power

[45] Vaughan Affidavit at ¶ 35.

[46] KRS 278.010(14).

provided electric service to its customers reliably, without rolling blackouts or any other energy supply disruption, relying on its demonstrably dependable power supply resources. Although an interruption in service does not necessarily equate to inadequate service, the continuous service that Kentucky Power provided to its customers certainly meets the definition of adequate service. In fact, the dependability of Kentucky Power's capacity and energy resources greatly exceeds the Kentucky statutory requirement to "hav[e] sufficient capacity to meet the maximum estimated requirements of its customers."[47] Kentucky Power's power supply demonstrated its dependability even when the actual requirements to serve its customers vastly exceeded any reasonable estimate for the applicable time period. Kentucky Power's owned generation assets, contracted-for capacity resources, and access to the PJM market mean that the Company is, was, and continues to be able to confidently assure its customers reasonable continuity of service.

Indeed, it would be unreasonable to fault any utility for experiencing power supply outages during an unforeseeable set of circumstances involving simultaneously an extreme weather event and the limited availability of the combined generation supply of power generators in the eastern United States. The requirements imposed by such an event should reasonably be expected to stretch the preparedness of any utility region's maximum estimated requirements expectations.

The fact that Kentucky Power nevertheless was able to draw on its capacity and energy resources to keep the lights and heat on during such an event allows only one conclusion: the Company met, and exceeded, its obligation to provide adequate service as required under Kentucky law. The Company's performance during Winter Storm Elliott conclusively confirms that Kentucky Power has the capacity and energy resources necessary to satisfy the adequate service requirements under Kentucky law (articulated in KRS 278.010(14)).

---

[47] KRS 278.010(14).

B. Kentucky Power Provides Adequate, Efficient, and Reasonable Service.

KRS 278.030(2) requires Kentucky Power to provide adequate, efficient, and reasonable service, and that is exactly what the Company does. Kentucky Power owns or contracts for sufficient capacity, and it has access to energy sufficient to ensure reasonable continuity of service, consistent with the definition for "adequate service."

As an initial matter, Kentucky Power prudently maintains and operates its owned generating units, and it did so during Winter Storm Elliott. The Mitchell Plant had already deployed its Winter Preparedness Plan and had additional personnel on site to support winter operations.[48] Both Mitchell Unit 1 and Unit 2 (collectively, the "Mitchell Units") were available and operating throughout the Winter Storm Elliott Period.[49] Both Mitchell Units performed favorably during Winter Storm Elliott as compared to their historic performance.[50] Big Sandy Unit 1 was in a Planned Outage status that, with the approval of PJM, was extended through the month of December due to unforeseen repairs that were necessary to complete in order to safely operate the Big Sandy Plant.[51] The Company could not have brought the unit back online to serve customers during Winter Storm Elliott without risking the Unit's catastrophic failure.[52] Accordingly, Kentucky Power prudently managed and operated its owned generation units during the Winter Storm Elliott period to help hedge its energy needs to the extent possible to do so.

[48] Kerns Affidavit at ¶ 4-5.

[49] *Id*. at ¶ 6.

[50] *Id*. Although Mitchell Unit 1 and Unit 2 were partially derated, those derates were almost entirely due to environmental limitations and not the storm or other factors. *Id.* at ¶ 9.

[51] *Id.* at ¶¶ 10-19.

[52] *Id.*

Kentucky Power could not have generated more power from Mitchell, nor brought Big Sandy online without risk of catastrophic failure.

In addition, it was also consistent with adequate, efficient, and reasonable service for Kentucky Power to rely on the PJM market for a portion of its energy needs. There is no statutory requirement in Kentucky that Kentucky Power own generation or contract for energy to meet customers' energy demand. As demonstrated above, Kentucky Power's combination of owned-generation, contracted-for capacity, and participation in the PJM market provides the Company with sufficient capacity and access to energy to meet the Company's maximum estimated customer demand and beyond.

In addition to ensuring access to energy supply and continuity of service, Kentucky Power also takes into account the cost to customers in doing so. Kentucky Power is constantly reviewing the market to determine how it can provide service to customers in the most economical way possible.[53] The Company does so based on the best available information it has at the time. For example, the Company actively reviewed the prices in the forward energy market for winter 2022/23 and determined based on forward energy prices and anticipated demand that it would be uneconomical for the Company to enter into contracts for energy for that season and more economical to rely on the spot energy market.[54] The Company's process and decision was reasonable and prudent based on the information available to the Company at the time.[55] The actual real-world energy prices for winter 2022/23 confirmed the soundness of the Company's analysis and decision.[56] To rely upon costs incurred during the four-day Winter Storm Elliott to

[53] Vaughan Affidavit at ¶¶ 27-28.

[54] *Id* at ¶¶ 27-29.

[55] *Id* at ¶ 30.

[56] *Id* at ¶¶ 31-34.

conclude that the Company provides service in an unreasonable manner would be to ignore the truly extraordinary conditions the storm presented.

Kentucky Power's combination of resources, in concert with participation in the PJM market, provides its customers with efficiencies that relying solely on owned-generation or solely on market energy purchases cannot. Both have their place. Owned generation limits reliance on market purchases and associated volatility. Participation in the PJM market gives the Company access to energy associated with tens of thousands of megawatts of generation, limiting the Company's outage risk and price risk from owned generation.

1. *Kentucky Power Has Not Ignored Its Customers.*

The Show Cause Order asserts that the Company failed to prudently anticipate its energy needs, and thereby failed to act in the best interest of its customers.[57] This cannot be further from the truth.

In addition to the incorrect premise that Kentucky Power is not providing adequate service, the Commission relies on testimony from another case, in which a witness who does not directly manage Kentucky Power's market purchase program responded to hypothetical questions, to make a blanket statement about the speed and ease of fixing a problem that does not exist and imply that the Company is taking no actions to protect customers. Although entering into a forward energy purchase might be a relatively straightforward process, doing so might not always be economically beneficial for customers, as demonstrated by the actual market costs for the winter 2022/23 season.

As described above, Kentucky Power prudently managed and operated its owned generation resources. As also described above, Kentucky Power has a robust process through which its market purchase strategy is managed for customers' financial benefit. The evaluation of

[57] Show Cause Order at 7.

the prudence of the Company's decisions regarding how it manages its market purchase strategy must be measured based on the information known and reasonably available to the Company at the time the decision was made, and it is well-established that it is inappropriate to use hindsight to evaluate the prudence of the Company's decisions.[58]

There is a broad spectrum of prudent decisions, and differing outcomes may result from the exercise of good business judgment. These truisms are borne of uncertainty, as no decision-maker can predict the future. The fact that there is a broad spectrum of prudent decisions is one of the reasons why the option of hedging power transactions is even available: no one would offer a hedge knowing that it will be in the money, and no one would acquire one knowing that it will not. Thus, it may be equally prudent for a utility to enter into a hedging transaction under particular circumstances or to decide not to do so under the same circumstances; it is irrelevant whether in hindsight a hedge may be in the money or not. Utilities such as Kentucky Power are afforded the discretion to make prudent decisions, based on their expertise and the particular circumstances before them at the moment the decision is made.[59]

The decisions that Kentucky Power made regarding the maintenance and operation of its owned generation and its decision not to make forward energy purchases for winter 2022/23 were prudent at the time, and in fact resulted in economic benefits to customers. Although prudence cannot be evaluated in hindsight, even in hindsight Kentucky Power's decisions regarding whether to enter hedging transactions *in fact resulted in lower costs to Kentucky Power and its customers.*

---

[58] *In the Matter of: Proposed Adjustment of the Wholesale Water Service Rates of the City of Pikeville, Kentucky* (Case No. 2002-00022) at 9 (Oct. 18, 2022) ("Hindsight cannot be used in evaluating the prudence of management's actions. Management must be judged on what was known or should have been known at the time of its decision.").

[59] *See, e.g., New England Power Company*, 31 FERC 61,047, 1985 WL 191206, *6 ("[W]e reiterate that managers of a utility have broad discretion in conducting their business affairs …").

2. *Kentucky Power's Long-Term Resource Planning Continues.*

The Company is mindful of the Commission's inquiry regarding how it proposes to render adequate service and the reasonable timeframe it intends to correct any failure to do so. As previously discussed, Kentucky Power has rendered adequate service to its customers, before, during, and after Winter Storm Elliott. The Company is proud that it was able to render reliable, safe, and dependable service to its customers, in an economical fashion, even in the face of extraordinary circumstances, including an extreme weather event combined with the unforeseeable unavailability of generation resources owned by numerous power suppliers in the eastern United States, including generation resources within the Commonwealth of Kentucky.

The Company intends to continue to provide better than adequate service to its customers. To do so, Kentucky Power plans to continue to rely on a combination of owned generating resources and market resources that are available to Kentucky Power as a member of PJM and an affiliate in the AEP system. The Company has submitted its current IRP, which is currently under Commission review in Case No. 2023-00092. This plan discusses in detail specific aspects of the Company's evaluation of its present and long-term capacity and energy needs, and of dependable and economically effective ways to meet those needs for the benefit of its customers. In addition, consistent with the current IRP, the Company anticipates filing with the Commission for authorization to obtain one or more energy and capacity resources, be it through construction, acquisition, power purchase agreement, or other contract form that may be prudent and effective.

C. <u>The Show Cause Order is Not Based on Substantial Evidence and Lacks Due Process.</u>

1. *The Commission's Findings Supporting the Issuance of the Show Cause Order Are Not Based on Substantial Evidence.*

The findings supporting the issuance of the Show Cause Order, including those based on evidence from other proceedings, are not based on substantial evidence. Commission orders must be supported by substantial evidence.[60] Substantial evidence is evidence of record bearing "sufficient probative value to induce conviction in the minds of reasonable … [persons]."[61] "Substantial evidence is more than a scintilla, and must do more than create a suspicion of the existence of the fact to be established."[62] In addition, the Commission must account for any evidence that fairly detracts from the finding made.[63]

The Show Cause Order lacks evidence that would support, or fairly detract from, the conclusion that Kentucky Power failed to render adequate, efficient, and reasonable service. For example, the Show Cause Order fails to describe what a prudent utility would have done or planned to do when faced with the same circumstances, or the cost or success of those actions in comparison to the ones the company undertook, as described herein. The absence of such evidence instead supports the conclusion that Kentucky Power did provide adequate, efficient, and reasonable service in connection with Winter Storm Elliott, and with respect to its Rockport UPA replacement strategy.

Further, the Commission relied on the records of other proceedings to support the issuance of the Show Cause Order.[64] Such evidence is incomplete, does not represent the full picture, and is taken out of context. Nor was the Company able to provide an informed response to or examination of the extra-record evidence, in the context of Winter Storm Elliott and its Rockport

---

[60] *Public Service Com'n of Kentucky v. Commonwealth*, 320 S.W.3d 660, 665 (Ky. 2010) (*citing National–Southwire Aluminum Co. v. Big Rivers Elec. Corp.,* 785 S.W.2d 503, 510 (Ky. App. 1990)).

[61] *Kentucky State Racing Com'n v. Fuller*, 481 S.W.2d 298, 303 (Ky. 1972).

[62] *George T. Stagg Co. v. O'Nan*, 286 Ky. 527, 151 S.W.2d 51, 54 (1941).

[63] *Revenue Cabinet v. South Hopkins Coal Co*., 734 S.W.2d 476, 479 (Ky. App. 1987).

[64] Show Cause Order at 5-7 (*e.g.* "It is clear to the Commission from the records of Case Nos. 2022-00283 and 2023-00145 that Kentucky Power does not have sufficient capacity available to serve customers' energy needs, has been aware of that shortcoming for a significant amount of time, understands the detriment that insufficiency can cause customers, has described the speed and ease by which it could fix that shortcoming, and yet has chosen not to address its inadequacy of service.").

UPA replacement strategy, prior to the issuance of the Show Cause Order. In addition, because Kentucky Power was not given the opportunity to provide such response or further evidence in the proper context, the Commission necessarily fails to take into account evidence that fairly detracts from the findings made. Therefore, such extra-record, out-of-context, and incomplete evidence does not constitute substantial evidence sufficient to support the issuance of the Show Cause Order.

Moreover, some findings contained in the Show Cause Order are contrary to evidence contained in the records cited by the Commission, such as:

- "[T]he December 8, 2022 termination of the Rockport Unit Purchase Agreement (UPA) represented a reduction in generation that resulted in Kentucky Power having an inadequate amount of available generation to produce energy to meet its peak native demands."[65]
- "Kentucky Power failed to provide sufficient evidence regarding the reasonableness of the generation unavailability at Mitchell and Big Sandy 1."[66]

Kentucky Power has maintained throughout various filings and past proceedings that Kentucky Power had access to sufficient energy supply via its participation in PJM. Kentucky Power also, despite having no notice that the reasonableness of its generation availability was being examined as part of the case, provided evidence regarding the same at the Mitchell Plant and Big Sandy in response to the Commission's data requests in Case No. 2023-00145.

Finally, the Commission's finding that "[s]ufficient generation capacity that can be used to serve the entirety of native demand acts as a physical hedge to market energy prices, and without adequate generation capacity, Kentucky Power and its customers are subject to higher prices from

[65] *Id*. at 5.

[66] *Id.* at 6; *see also* Kerns Affidavit at Exhibit TCK-1.

market purchases for at least the amount the utility is short of its native demand,"[67] is a conclusory statement unsupported by evidence. Accordingly, it cannot constitute substantial evidence that the Company failed to render adequate, efficient, and reasonable service in connection with Winter Storm Elliott or with respect to its Rockport UPA replacement strategy. Thus, the Commission did not issue the Show Cause Order based on substantial evidence, and its findings contained therein are not based on substantial evidence.

2. *Kentucky Power Is Entitled to Due Process; if The Show Cause Order Is Not Dismissed, the Company Is Entitled The Establishment of an Appropriate Record in this Matter.*

The Company is entitled to due process. As explained above, the Company was not provided notice of the Commission's intent to rely on evidence from past proceedings in future proceedings, or in contexts other than those of the original proceedings. The Company was not given the opportunity to know what evidence the Commission was considering to support its issuance of the Show Cause Order, or to test and refute such evidence.

Such practices fall short of providing Kentucky Power due process as required by the Kentucky Constitution and the Fourteenth Amendment. Section 2 of the Kentucky Constitution and the due process clause of the Fourteenth Amendment guarantee all litigants before the Commission the right to know the issues and evidence being considered and are entitled to the opportunity to put on evidence to support their position and to test, explain, and/or refute any evidence to the contrary.[68]

Furthermore, if the Show Cause Order is not dismissed as Kentucky Power has demonstrated in this Response is appropriate, the Company is entitled to due process prior to the

[67] Show Cause Order at 5.

[68] *Kentucky American Water Co. v. Commonwealth ex rel. Cowan*, 847 S.W.2d 737, 741 (Ky. 1993); *Utility Regulatory Comm'n v. Kentucky Water Service Co., Inc.,* 642 S.W.2d 591, 593 (Ky. App. 1982).

institution of any penalties or other remedies. This includes sufficient notice and the opportunity to know all evidence the Commission is considering and upon which it will rely in connection with the show cause proceeding, sufficient opportunity to test or refute the evidence upon which the Commission will rely, and sufficient opportunity to present its own evidence, including any necessary context or additional information that would inform the evidence relied upon by the Commission. Specifically, but not exhaustively, the Company respectfully requests that it be provided sufficient notice, which would include a meaningful opportunity to respond, of any evidence from past cases to be relied upon or considered by the Commission to support the issuance of any order in this proceeding.

As stated previously, the Commission relied on the records of other proceedings to support the issuance of the Show Cause Order.[69] However, due process requires that the Commission provide Kentucky Power with notice of its intention to rely on evidence from past proceedings. It must also give Kentucky Power the opportunity to know what evidence the Commission is considering. The Commission further must give Kentucky Power an opportunity to put on its own evidence to support its positions and to test, explain, and/or refute any evidence to the contrary *in the context in which that evidence will be considered.*

III. Conclusion

Through its combination of owned-generation, contracted-for capacity, and participation in the PJM market, Kentucky Power provides service to its customers that is adequate, efficient, and reasonable. Kentucky Power Company respectfully requests the Commission dismiss the

[69] Show Cause Order at 5-7 (*e.g.* “It is clear to the Commission from the records of Case Nos. 2022-00283 and 2023-00145 that Kentucky Power does not have sufficient capacity available to serve customers' energy needs, has been aware of that shortcoming for a significant amount of time, understands the detriment that insufficiency can cause customers, has described the speed and ease by which it could fix that shortcoming, and yet has chosen not to address its inadequacy of service.”).

Show Cause Order and the proceeding discussed therein. In the alternative, Kentucky Power requests that the Commission establish a procedural schedule that provides a meaningful opportunity for a fully-developed record on the issues raised in the Show Cause Order including the opportunity to provide witness testimony, discovery, rebuttal witnesses, an evidentiary hearing, and an opportunity for post-hearing briefing.

Respectfully submitted,

Katie M. Glass
STITES & HARBISON PLLC
421 West Main Street
P. O. Box 634
Frankfort, Kentucky 40602-0634
Telephone: (502) 223-3477
Fax: (502) 560-5377
kglass@stites.com

Kenneth J. Gish, Jr. (KBA #93970)
K&L GATES LLP
300 South Tryon Street, Suite 1000
Charlotte, North Carolina 28202
Telephone: (704) 331-7424
Fax: (704) 353-3124
ken.gish@klgates.com

COUNSEL FOR KENTUCKY POWER COMPANY

Exhibit A

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Investigation of the	)	
Service, Rates and Facilities of	)	Case No. 2021-00370
Kentucky Power Company	)	

AFFIDAVIT OF ALEX E. VAUGHAN

STATE OF OHIO)
)
COUNTY OF FRANKLIN)

I, Alex E. Vaughan, of lawful age, being duly sworn, depose and state as follows:

1. My name is Alex Vaughan. I am employed by American Electric Power Service Corporation ("AEPSC") as Managing Director – Renewables & Fuel Strategy. AEPSC is a wholly owned subsidiary of American Electric Power Company, Inc. ("AEP"). AEP is the parent company of Kentucky Power Company ("Kentucky Power" or the "Company").

2. The purpose of this Affidavit is to describe the circumstances that caused Kentucky Power to incur approximately $11.5 million of Winter Storm Elliott Peaking Unit Equivalent ("PUE") purchased power expense in December 2022. This Affidavit demonstrates that the Winter Storm Elliott PUE expense was prudently incurred; that Kentucky Power had in December 2022, and presently has, sufficient capacity available; and that the Company's actions in December 2022 were consistent with its Commission-reviewed 2019 integrated resource plan filing.[1] The Affidavit further demonstrates that the Company has provided adequate service in its service territory.

Capacity and Energy Availability

3. As an initial matter, it is important to distinguish between capacity and energy. Generation capacity is defined as the capability to generate energy. Capacity is a planning concept. The Company ensures that it has access to adequate resources to meet estimated peak demand plus a reserve margin. Energy, by contrast, is the actual electricity that customers consume. In actual operations, the energy the Company's customers consume may or may not come from the Company's generation capacity resources. Sometimes it is less costly to consume energy generated by other power plants connected to the grid operated by PJM, the balancing authority to which the Company belongs. Other times, the Company's capacity resources may need to be serviced and are off line, and are thus unavailable to generate energy.

---

[1] *In the Matter of: Electronic 2019 Integrated Resource Planning Report of Kentucky Power Company*, Case No. 2019-00443.

The Company Has Access to Sufficient Capacity to Serve Customers

4. The Company plans for and meets its generation capacity needs through PJM, which is the Regional Transmission Organization ("RTO") to which the Company belongs. PJM implements a resource adequacy construct approved by the Federal Energy Regulatory Commission ("FERC") designed to ensure sufficient capacity to meet peak load throughout the 13-state PJM footprint. Under the PJM construct, load-serving entities like Kentucky Power must procure sufficient capacity to meet their peak load plus a reserve margin. The capacity obligation under PJM's construct is currently determined using a summer 5CP measurement. (PJM is currently considering reforms to its construct that would separately impose a winter capacity obligation and a summer capacity obligation.)

5. Kentucky Power meets its capacity obligations under PJM's construct through what is known as a "Fixed Resource Requirement Plan" ("FRR Plan"). Together with other AEP affiliates, Kentucky Power identifies resources owned or under contract that are sufficient to meet its capacity obligations. The FRR Plan is reviewed by PJM, which confirms that the resources identified will provide adequate capacity to meet the Company's capacity obligations.

6. The Company's generation capacity resources include a 50% undivided interest in the Mitchell plant and Big Sandy Unit 1. Until December 2022, they also included a 15% share of the Rockport coal-fired generation facility in Indiana. Kentucky Power's share of the capacity from the Rockport plant was 393 MW, and at the time the Rockport UPA terminated, the Company's owned or contracted-for capacity had been approximately 200 MW greater than its estimated and recent historic requirements. As a result of declining load and its ability to rely on the PJM market, the Company elected not to renew the agreement. The Company instead engaged in short-term capacity purchases to meet its capacity obligations for the remainder of the 2022/23 Planning Year and for the 2023/24 Planning Year. Specifically, the Company acquired 152 MW of capacity for the remainder of the 2022/23 Planning Year and forecasts that it will require 65 MW of capacity through the PJM 2023/2024 Planning Year ending May 31, 2024.

7. As noted, PJM's capacity construct is based on a summer peak. However, Kentucky Power is a winter peaking utility. This benefits Kentucky Power customers by saving them money, without any reduced reliability. PJM's summer peaking construct means that Kentucky Power customers can meet their reliability requirement with less capacity than they would need if the reliability requirement were based on the winter peak. But because PJM secures an annual capacity product, and does so in a quantity sufficient to meet the RTO's higher summer peak, PJM has more than sufficient capacity (and energy) available to meet the RTO's winter peak—including Kentucky Power's. This results in financial benefits to Kentucky Power customers and customers of other winter-peaking utilities.

8. Kentucky Power has never itself owned or had contractual entitlements to generating capacity sufficient to cover the entirety of its peak native demand during all hours of the year. It has participated historically in the AEP Interconnection Agreement (the East Pool) and then the PJM RTO to economically cover the balancing needs required to meet the winter peak. Historically, owning or securing contractual entitlements to the needed capacity to cover the entirety of peak native load would have been significantly more expensive than the Company's approach of securing excess energy requirements in the PJM spot energy market.

The Company Has Access to Energy Sufficient to Serve Customers

9. As a member of PJM, the Company offers 100% of its generation output (energy) from its owned and contracted-for resources into the PJM market, and acquires 100% of its energy requirements from the PJM market. Kentucky Power's customers benefit from efficiencies in the regional generation portfolio, which reduce the cost of the energy required to serve them.

10. The capacity available from Kentucky Power's owned generation assets (a 50 percent undivided interest in the coal-fired Mitchell Generation Station and the natural gas-fired Big Sandy Unit 1 Generating Station) is sufficient in most circumstances to provide in effect the energy required to serve Kentucky Power's customers. However, because of outage schedules and the relative cost (compared to spot market prices) of those assets, Kentucky Power also relies directly on the PJM energy market to provide energy for its customers.

11. Procuring a complete physical hedge to effectively insulate Kentucky Power from energy market prices—that is, owning or contracting for generation capacity sufficient to meet demand at all hours of the year—would be more expensive than buying energy on the PJM spot market during times of low energy market prices, such as those that have existed for most of the last 15 years. Therefore, the Company's plan for covering load obligations in excess of owned or contracted-for generation supply has for years been, and continues to be, to purchase the balance of its energy requirements from the PJM energy spot markets. The Company's customers receive the lower of the cost to generate or the market price for energy for the portion of their load requirements covered by the Company's generation resources, and the market price for energy for the balance of their load requirements, as determined by PJM's FERC approved tariff and economic dispatch model.

Kentucky Power's 2019 Integrated Resource Plan

12. An integrated resource plan ("IRP") is a triennially-filed plan that presents information to the Commission regarding an electric utility's historical and projected demand, resource, and financial data, other operating performance and system information, and the facts, assumptions, and conclusions upon which the plan is based and the actions it proposes.[2] Upon receipt of an IRP, Kentucky regulations require the Commission to establish a procedural schedule on the IRP.[3] Based upon its review of a utility's IRP and related information, Commission Staff is required to issue a report summarizing its review and offering suggestions and recommendations to the utility for subsequent filings.[4] The regulations further provide that a utility should respond to the Staff's comments and recommendations in its next IRP filing.[5]

[2] 807 KAR 5:058, Section 1(2).

[3] *Id.*, Section 11(1).

[4] *Id.*, Section 11(3).

[5] *Id.*, Section 11(4).

13. Kentucky Power filed its 2019 IRP on December 20, 2019.[6] The Company's IRP presented a Preferred Plan under which Kentucky Power explained it would meet its customers' requirements over the following five years with existing resources and through the use of short-term market purchases and modest investments in renewable resources and energy efficiency.[7] The IRP assumed that the Rockport Unit Power Agreement ("UPA") would expire in December 2022.[8] It also assumed that following the expiration of the UPA in December 2022, Kentucky Power would work with other AEP operating companies in the Power Coordination Agreement to meet its obligations through the end of May 2023.[9] The IRP further explained that for the PJM Planning Year beginning June 1, 2023, Kentucky Power would arrange to meet its capacity obligations through the bilateral market or other means.[10]

14. After a procedural schedule that included multiple rounds of data requests and responses, a one-day hearing, and post-hearing data requests, Staff issued its Staff Report on February 15, 2021. Kentucky Power and the Attorney General and Kentucky Industrial Utility Customers, Inc. ("KIUC") (collectively, "AG-KIUC") filed comments in response to the Staff Report. Consistent with the Company's Preferred Plan, AG-KIUC advocated for the use of short-term bilateral market capacity purchases and the PJM spot energy market in lieu of the Company owning long-term assets to meet its excess energy needs. In their joint comments on Kentucky Power's 2019 IRP Preferred Plan, AG-KIUC argues that "the Company should adjust its Preferred Plan to include additional MPs [market purchases], and it should not be overlooked that we have been in a low-cost environment for more than ten years with no indication this will change any time soon."[11] AG-KIUC's joint comments also state:

> In its response to Staff's Post Hearing Request No. 2, the Company noted that when its winter peak demand is greater than its summer peak demand obligation, it buys energy from the pool. When this situation occurs, it does not mean that Kentucky Power suffers from a reliability issue, but instead it means it is more economic for Kentucky Power to purchase energy from within the PJM market than for Kentucky Power to construct new resources, especially since there is sufficient capacity available in PJM to meet Kentucky Power's winter peak. As long as Kentucky Power meets its PJM summer peak demand obligation, and PJM ensures that the entirety of the PJM System is reliable on a year round basis, then it would become an economic matter as to whether Kentucky Power should construct additional

---

[6] *See In the Matter of: Electronic 2019 Integrated Resource Planning Report of Kentucky Power Company*, Case No. 2021-00443, Integrated Resource Planning Report to the Kentucky Public Service Commission, Volume A (Dec. 20, 2019).

[7] *See, e.g., id.* at p. ES-4.

[8] *See, e.g., id.* at 41.

[9] *Id.*

[10] *Id.*

[11] Joint Review of Kentucky Power's 2019 Integrated Resource Plan at 9, *In the Matter Of: Electronic 2019 Integrated Resource Planning Report of Kentucky Power Company*, Case No. 2019-00443 (February 25, 2021).

capacity to avoid having to purchase during the winter period. Even if the Company were to construct physical assets such as combustion turbine units to satisfy its winter peak, Kentucky Power possibly would still purchase energy from the PJM market during the winter as opposed to running its newly built resources since PJM market resources could be cheaper to operate than Kentucky Power's new resources.[12]

15. The Company, consistent with its 2019 IRP Preferred Plan and with AG-KIUC's comments in that proceeding, has been taking this approach regarding its capacity and energy needs outlined above since the end of the Rockport UPA. This strategy has been financially advantageous to customers, who have paid less for purchased power overall at predominantly low market energy rates than they would have otherwise paid for bilaterally contracted or owned generation.

16. To the extent that the Company may add additional owned or contracted capacity and energy resources in the future to replace the energy and capacity from the Rockport UPA's expiration, those resources would contribute in the future to reducing the Company's amount of spot market energy purchases from PJM. However, it should be noted that resource acquisitions are generally informed by long-range integrated resource planning and forecasting that utilizes normative forecasts that do not account for extreme outlier events like Winter Storm Elliott, discussed further below. As I will explain, the weather and resulting conditions in the PJM energy market during Elliott were an outlier. It is highly unlikely that traditional resource planning would result in the Company being insulated from all possible PJM energy market fluctuations.

<u>The Peaking Unit Equivalent Construct</u>

17. The Company recovers certain purchased power expense through its Fuel Adjustment Clause (Tariff FAC). Based on prior Commission precedent, recovery of purchased power costs through the FAC is limited by the FAC Purchase Power Limitation. The FAC Purchase Power Limitation is a calculation that caps the amount of purchase power expense to be recovered in the Company's monthly FAC surcharge. The calculation compares the cost of actual purchased power on an hourly basis to the cost of the Company's highest-cost unit or the theoretical peaking equivalent ("PUE") and caps the FAC-recoverable purchased power expense at the cost ($/MWh) of the highest cost generating unit (Company owned or peaking unit equivalent). The PUE is not a cap on the level of costs that are recoverable, but rather on what level of costs can be recovered in the monthly FAC rate updates. The PUE construct was created as a proxy because Kentucky Power does not own any peaking units. The FAC Purchase Power Limitation is applied to all purchased power expense used to serve the Company's customers.

18. Instances where purchased power costs exceed the PUE calculation generally occur because the implied heat rate of the PJM energy market is higher than that of the hypothetical combustion turbine used in the PUE calculation, the locational natural gas price of the marginal unit in PJM's hourly economic dispatch solution is higher than that of the price used in the PUE calculation, or some combination thereof. The purchased power costs are still reasonably incurred

[12] *Id.* at 16.

as they are the product of hourly economic dispatch, which is optimized across the PJM RTO pursuant to PJM's FERC-approved tariff. The purchased power is the next cheapest spot source of energy available to serve customers.

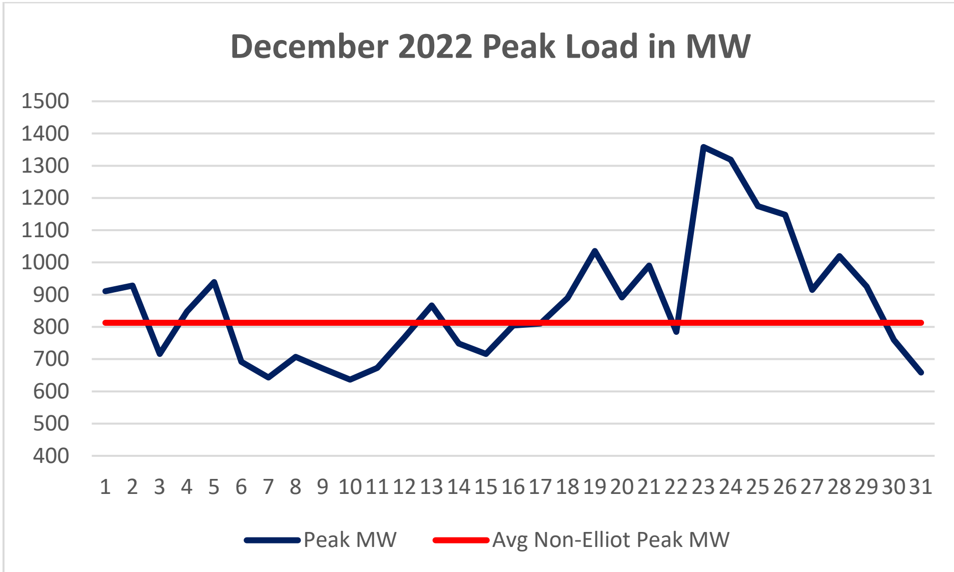
Winter Storm Elliott

19. Winter Storm Elliott ("Elliott") was an extreme cold weather event that included rapid temperature drops and record cold temperatures across much of the United States. Elliott occurred December 23, 2022 through December 26, 2022, in the PJM region (the "Winter Storm Elliott Period").[13] The resulting load during this period of time was an extreme outlier in both magnitude and timing. The Company's own peak load during the Winter Storm Elliott Period was 1,358 MW, 46% higher than the Company's previous 12-month average peak demand ("12CP") of 929 MW. In 85 of the 96 hours during the event, the Company's hourly average load was higher than its most recent 12CP demand. The energy consumption in the Kentucky Power service territory during the Winter Storm Elliott Period totaled 107,356 MWh, compared to 60,275 MWh during the same period a year earlier, an increase of 47,081 MWh.

20. Figure AEV-1 below illustrates the Company's daily peak demand during the month of December 2022. As can be seen, there is an extreme increase in demand during Elliott, including the 1,358 MW peak during hour ending 2100 on December 23, 2022. The flat line in Figure AEV-1 is the average peak demand during the non-Elliott days in December (813 MW). The Company's peak demand during Elliott was 545 MW higher than the average peak demand for the other 27 days of December 2022. Before this, one has to go back to January 2018 to find a Company peak higher than what was experienced during Elliott, and the Company has only had eight monthly peaks in the last decade greater than the Elliott peak. This illustrates the magnitude of the demand on the Company's system resulting from Elliott's extreme cold weather.

[13] PJM defined the Winter Storm Elliott Period as December 23, 2022, through December 26, 2022, and this is the time period used for purposes of this testimony. The Company also has referred to the Winter Storm Elliott Period when describing its generation performance as December 23, 2022, through December 27, 2022 (see Affidavit of Timothy C. Kerns).

Figure AEV-1



21. The drastic temperature drop and higher than forecasted load caused PJM to dispatch generation reserves, many of which failed to perform. Despite these challenges, however—and unlike neighboring balancing authorities including in Kentucky—PJM, including Kentucky Power, did not shed load due to a power supply-related outage. The lights and heat stayed on in Kentucky Power's service territory.

22. Additionally, as discussed in the accompanying affidavit of Tim Kerns, the Company's generating units performed well. Kentucky Power did not incur any capacity performance penalty during the Winter Storm Elliott Period. Due to the Company's prudent management of its available coal supplies during 2022, the Mitchell Plant was available to run and operated continuously during this time. The AEP Companies' FRR plan, in which Kentucky Power participates, also did not incur any capacity performance penalty, as it benefitted from the diversity of generation resource types and locations utilized by the Companies in the plan.

23. Nevertheless, the unanticipated high load and rapid load increase combined with generation outages due to cold weather and fuel issues resulted in PJM's designation of Performance Assessment Intervals ("PAIs") on December 23, 2022 and December 24, 2022. PAIs are triggered when PJM declares an emergency action in the RTO. During the PAIs, the load weighted LMP reached the system marginal price cap of $3,700/MWh as a result of the supply/demand imbalance during emergency operations.

24. Figure AEV-2 below shows the real-time LMPs over the Winter Storm Elliott Period, and Figure AEV-3 shows real-time LMPs over the month of December 2022 to put into context how much of an outlier pricing during Elliott was.

Figure AEV-2

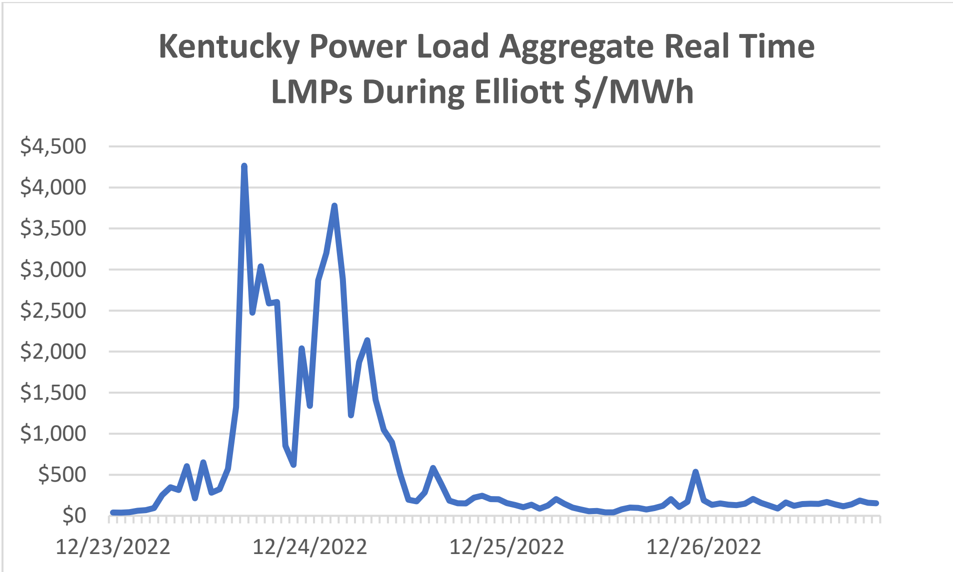
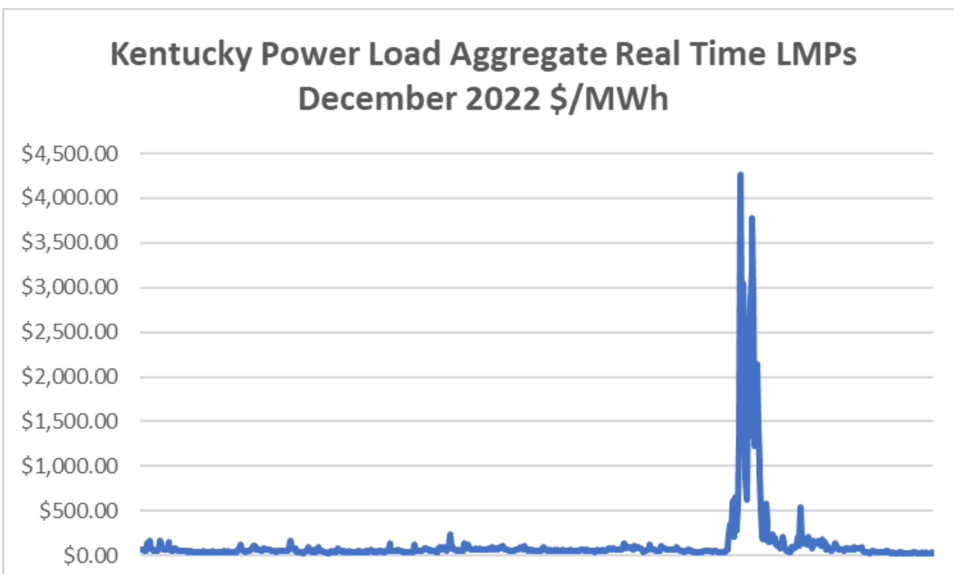


Figure AEV-3



25. Kentucky Power took all reasonable efforts available to it to reduce the total amount of purchased power expense during the Winter Storm Elliott Period. In addition to operating the Mitchell Plant through the event and putting out a general call for conservation, the Company curtailed all of its interruptible customers[14] on December 23, 2022, and December 24, 2022, and those customers reduced their operations to their contracted firm service level during the curtailments.

26. There were no lower-cost sources of purchased power available to the Company during the Winter Storm Elliott Period. Winter Storm Elliott was a PJM system emergency; if excess power were available in the market, then scarcity pricing and emergency conditions would not have occurred. It is fundamental under economic principles of supply and demand that a willing market seller of energy would not sell available energy during such an event for less than the transparent spot market price of energy. Moreover, PJM was helping to support neighboring balancing areas which were experiencing load shed, including other service territories in Kentucky.

Kentucky Power Was Prudent In Its Market Purchase Strategy for the Winter of 2022/23

27. The Rockport UPA provided Kentucky Power with a physical hedge against energy spot prices. By contrast, the short term capacity acquired by the Company following the termination of the Rockport UPA does not give Kentucky Power access to the energy produced from the Projects providing capacity to the Company. Therefore, in anticipation of the termination of the Rockport UPA, Company personnel and subject matter experts within AEPSC met frequently during 2022 to develop a strategy to optimize the Company's market purchase strategy. The group considered a finite coal supply in response to an increasingly volatile energy market, reviewed fuel inventory levels at each coal-fired generating unit, the expected deliveries and price of coal, expected demand, short-term market prices, and forward prices. Ultimately, the Company decided to rely on the PJM spot market, and not to procure physical or financial hedges beyond its existing Big Sandy and Mitchell plants because, based on all available information at the time, the latter approach would have been significantly more expensive for customers.

28. To mitigate exposure to spot energy market prices, the Company can hedge through forward power purchases. Although it is not possible to perfectly predict future energy prices, utilization of forward power purchases over a period of time can help reduce exposure to spot market energy price volatility. These can include seasonal or monthly forward contracts. But forward purchases come with a cost, and leave customers at risk of paying more than the spot market if electricity prices turn out to be lower than the forward price.

[14] Customers taking service under Tariff DRS or special contract.

29. As the result of global factors, including the war in Ukraine, the transition out of the COVID-19 pandemic, and high demand for U.S. liquified natural gas ("LNG"), natural gas prices rose to unprecedented levels. These increases in natural gas prices resulted in historically high forward energy prices. Indeed, during 2022, PJM's energy markets experienced historic volatility and price increases, resulting in the highest average energy market price levels since the Company joined PJM in 2004. Because the forward energy prices so far exceeded historical energy prices, creating the significant potential that actual market prices would be lower than the forward prices, the Company elected not to make any forward energy purchases for the winter of 2022-2023.

30. This decision was prudent at the time, and in fact resulted in economic benefits to customers. Despite Winter Storm Elliott, over the course of 2022 during the extreme escalation in gas and power prices, forward power purchases to hedge against market prices for the winter would have resulted in a more costly outcome compared to the strategy the Company deployed.

31. Figure AEV-4 below shows the costs the Company would have incurred by entering forward energy contracts for the December 2022 through March 2023 time period in an amount sufficient to replace the Rockport UPA (96 MW),[15] and compares those costs to the average liquidated (that is, actual) energy market price in each of those months.

32. To illustrate by way of example: in July, the Company could have entered into a forward energy purchase for energy produced in January at an average price of $113.72/MWh. The actual average liquidated price—that is, the price on the spot market —for January 2023 was $36.22/MWh. If the Company had entered into a forward energy purchase of 96 MW in August for January energy, the Company's purchased power expense for that month would have been $5,518,062 higher than it actually was. If the Company had entered into a forward energy purchase of 96 MW in July for the winter season, the Company's purchased power expense would have been $14,263,151 higher than it actually was.

33. As the chart shows, the cost for a forward energy purchase of 96 MW for the winter season would have been between $11 million and nearly $19 million more than the total cost of spot market purchases, depending on when (from July to November) the forward purchase was made.

[15] 96 MW is the simple average of the short-term capacity purchased to meet Kentucky Power's reliability requirement following the Rockport UPA's termination, for the planning years 2022/23 through 2025/26.

Figure AEV-4 - Hypothetical Forward Purchased Power Transaction for 96 MW

MW of Purchased Power Comensurate with RP UPA Replacement Capacity		96			
July Forwards	**December**	**January**	**February**	**March**	**Total**
Forward Price	$87.96	$113.72	$106.52	$76.42	
Liquidated Price	$83.85	$36.22	$27.81	$28.80	
Increase in Purchase Power Exp	**$292,635**	**$5,518,062**	**$5,061,872**	**$3,390,582**	**$14,263,151**
August Forwards	**December**	**January**	**February**	**March**	**Total**
Forward Price	$108.04	$136.92	$126.07	$78.07	
Liquidated Price	$83.85	$36.22	$27.81	$28.80	
Increase in Purchase Power Exp	**$1,722,347**	**$7,169,921**	**$6,319,140**	**$3,508,063**	**$18,719,471**
September Forwards	**December**	**January**	**February**	**March**	**Total**
Forward Price	$94.97	$126.51	$111.50	$75.71	
Liquidated Price	$83.85	$36.22	$27.81	$28.80	
Increase in Purchase Power Exp	**$791,753**	**$6,428,720**	**$5,382,137**	**$3,340,030**	**$15,942,640**
October Forwards	**December**	**January**	**February**	**March**	**Total**
Forward Price	$73.45	$106.30	$91.27	$67.17	
Liquidated Price	$83.85	$36.22	$27.81	$28.80	
Increase in Purchase Power Exp	**($740,488)**	**$4,989,752**	**$4,081,138**	**$2,731,975**	**$11,062,376**
November Forwards	**December**	**January**	**February**	**March**	**Total**
Forward Price	$80.90	$99.41	$91.97	$67.02	
Liquidated Price	$83.85	$36.22	$27.81	$28.80	
Increase in Purchase Power Exp	**($210,042)**	**$4,499,179**	**$4,126,155**	**$2,721,295**	**$11,136,586**

34. If the Company had entered forward energy contracts for the winter season in an amount larger than 96 MW, then customer costs would have been higher still. By way of example, if the Company had procured 283 MW[16] in forward energy for the winter season, total customer costs would have been between $32 million and $55 million higher than the cost from spot market purchases of that quantity. This is shown in the Figure AEV-5 below:

[16] Peak Kentucky Power load during Elliott minus generation resource (Mitchell and Big Sandy 1) ICAP.

Figure AEV-5 - Hypothetical Forward Purchased Power Transaction for 283 MW

MW Needed to Cover Elliott Peak	283				
July Forwards	**December**	**January**	**February**	**March**	**Total**
Forward Price	$87.96	$113.72	$106.52	$76.42	
Liquidated Price	$83.85	$36.22	$27.81	$28.80	
Increase in Purchase Power Exp	**$864,103**	**$16,293,909**	**$14,946,855**	**$10,011,819**	**$42,116,685**
August Forwards	**December**	**January**	**February**	**March**	**Total**
Forward Price	$108.04	$136.92	$126.07	$78.07	
Liquidated Price	$83.85	$36.22	$27.81	$28.80	
Increase in Purchase Power Exp	**$5,085,802**	**$21,171,569**	**$18,659,357**	**$10,358,721**	**$55,275,449**
September Forwards	**December**	**January**	**February**	**March**	**Total**
Forward Price	$94.97	$126.51	$111.50	$75.71	
Liquidated Price	$83.85	$36.22	$27.81	$28.80	
Increase in Purchase Power Exp	**$2,337,913**	**$18,982,929**	**$15,892,546**	**$9,862,545**	**$47,075,934**
October Forwards	**December**	**January**	**February**	**March**	**Total**
Forward Price	$73.45	$106.30	$91.27	$67.17	
Liquidated Price	$83.85	$36.22	$27.81	$28.80	
Increase in Purchase Power Exp	**($2,186,537)**	**$14,733,898**	**$12,050,914**	**$8,067,062**	**$32,665,337**
November Forwards	**December**	**January**	**February**	**March**	**Total**
Forward Price	$80.90	$99.41	$91.97	$67.02	
Liquidated Price	$83.85	$36.22	$27.81	$28.80	
Increase in Purchase Power Exp	**($620,220)**	**$13,285,317**	**$12,183,842**	**$8,035,525**	**$32,884,465**

35. Based on this data, the only way a hypothetical purchased power transaction would have potentially benefitted the Company's customers is if the Company had perfect foreknowledge of the unknown Winter Storm Elliott to come, so purchased forward contracts only for December and not for the rest of the winter, and then had the luck to time its purchase in October or November.

36. There likewise would have been no material benefit for customers if the Company had purchased a block of power to replace Big Sandy Unit 1's 295 MW of generation when it became known that the emergent generator issue with Big Sandy Unit 1[17] would keep the unit in a planned outage for all of December 2022. Had the Company purchased that block of power[18] for the remainder of the month of December after the equipment issue was discovered on December 2, 2022, total purchased power costs realized would not have changed materially. Forward pricing for the balance of December 2022 was $82.93/MWh and the average December 2022 liquidated price was $83.85. Therefore, less than a dollar per MWh (or roughly $190,000 in total) of savings was hypothetically possible. It should be noted that making such a transaction at a single point in time, rather than layering in over time, can be financially risky. This is very evident when looking out just a single month from December 2022 to January 2023, when the average PJM spot market price shown in Figure 4 dropped to just $36.22/MWh.

37. Winter Storm Elliott was not just a Kentucky Power issue. It financially and operationally impacted many utilities in the region. However, Kentucky Power kept the lights and heat on during a time period when customers needed it. There was no reasonable and foreseeable way for the Company to have avoided the resulting PJM energy market exposure in a way that would have materially reduced the realized costs.

[17] As discussed in more detail by Company Witness Kerns, the issue was discovered on December 2, 2022.

[18] 295 x 696 hours in the balance of the month = 205,320 MWh of hypothetical purchased power transaction.

Further, affiant sayeth not.

Alex E. Vaughan
Managing Director, – Renewables & Fuel Strategy

SUBSCRIBED AND SWORN TO BEFORE ME, on the 20th day of July, 2023, to certify which witness my hand and official seal.

Notary Public in and for The State of Ohio

My commission expires: N/A

BRETT E. SCHMIED, Attorney At Law
NOTARY PUBLIC - STATE OF OHIO
My commission has no expiration date
Sec. 147.03 R.C.

Exhibit B

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Investigation of the	)	
Service, Rates and Facilities of	)	Case No. 2021-00370
Kentucky Power Company	)	

AFFIDAVIT OF TIMOTHY C. KERNS

COMMONWEALTH OF KENTUCKY	)
	)
COUNTY OF BOYD	)

I, Timothy C. Kerns, of lawful age, being duly sworn, depose and state as follows:

1. My name is Timothy C. Kerns. I am employed by Appalachian Power Company ("Appalachian Power") and Wheeling Power Company ("Wheeling Power") as Vice President of Generating Assets. Appalachian Power and Wheeling Power are wholly owned subsidiaries of American Electric Power Company, Inc. ("AEP"). AEP is the parent company of Kentucky Power Company ("Kentucky Power" or the "Company"). Immediately prior to my current role, I was Vice President of Generating Assets for Kentucky Power and Indiana Michigan Power Company from 2020 to 2023.

2. As further detailed in the Affidavit of Alex E. Vaughan, Winter Storm Elliott was a bomb cyclone[1] that impacted the PJM region over the Christmas period of December 2022, causing a rapid temperature drop and extreme cold weather.[2]

3. The purpose of this Affidavit is to provide information regarding the performance of the Company's generation fleet during the Winter Storm Elliott Period. This Affidavit demonstrates that the Mitchell Plant was available and performed well during the entirety of the Winter Storm Elliott Period. It also demonstrates that the Planned Outage at the Big Sandy Plant during Winter Storm Elliott was reasonable, appropriate, and approved by PJM.

[1] A bomb cyclone is a large, intense storm that rapidly intensifies and is defined by a sudden and significant drop in atmospheric pressure.

[2] For purposes of this affidavit, I refer to the period December 23, 2022, through December 27, 2022, as the "Winter Storm Elliott Period".

Mitchell Plant Winter Storm Elliott Preparation and Performance

4. The Mitchell Plant undertakes significant winter preparedness measures each year. In preparation for winter, the Mitchell Plant implements a "Winter Preparedness Plan." In 2022, the plant implemented the "Winter Preparedness Plan" starting on October 3, 2022. The standard plan included employee training, completing preventative maintenance work orders, performing equipment checks, replenishing supplies, and other winter preparedness activities. Plant personnel completed a cold weather site specific plan review on October 19, 2022, and completed training on the North American Electric Reliability Council cold weather reliability standards by October 31, 2022. Cold Weather Preparedness and Winterization checks conducted as preventative maintenance activities were completed by November 2, 2022.

5. Additionally, in anticipation of Winter Storm Elliott, Mitchell Plant staffing was increased to at least one on-site member from the plant leadership team, and additional plant operations personnel and contractor support were brought on site.

6. Both Mitchell Unit 1 and Unit 2 (collectively, the "Mitchell Units") were available and operating throughout the Winter Storm Elliott Period. Both Units had a 0% forced outage factor[3] and 0% maintenance outage factor[4], meaning that at no point during the event were either of the Mitchell Units unavailable. As shown in Exhibit TCK-1, attached, Mitchell Unit 1 had a Net Capacity Factor[5] ("NCF") of 80.3% and Mitchell Unit 2 had an NCF of 74.1% during the Winter Storm Elliott Period. During Winter Storm Elliott, Unit 1 had an equivalent availability factor[6] ("EAF") of 86.3%, and Unit 2 had an EAF of 78.4%.

7. Both Mitchell Units performed favorably during Winter Storm Elliott as compared to their historic performance. Figure TCK-1 below compares each Mitchell Unit's performance during the Winter Storm Elliott Period to their average and highest annual NCF and EAF over the period 2016 through 2021:

[3] The forced outage factor is the ratio of ((All hours experienced during forced outages) to the number of hours in the period being reported that the unit was in the active state) x 100%.

[4] The maintenance outage factor is the ratio of ((All hours experienced during maintenance outages) to the number of hours in the period being reported that the unit was in the active state) x 100%.

[5] Net Capacity Factor is defined as the ratio of the generating unit's ((net actual generation) to its net maximum capacity for the number of hours in the period being reported that the unit was in the active state) x 100%.

[6] Equivalent Availability factor is the ratio of ((Available hours – equivalent planned derated hours – equivalent unplanned derated hours – equivalent seasonal derated hours) to the number of hours in the period being reported that the unit was in the active state) x 100%.

Figure TCK-1: Mitchell Unit Performance:
Winter Storm Elliott Period Compared to 2016-2021

Mitchell Unit	Winter Storm Elliott Period NCF	Average NCF (2016-2021)	Highest NCF (2016-2021)	Winter Storm Elliott Period EAF	Average EAF (2016-2021)	Highest EAF (2016-2021)
Unit 1	80.3%	36.9%	52.%	86.3%	57.1%	68.1%
Unit 2	74.1%	46.6%	65.8%	78.4%	69.3%	84.4%

8. As demonstrated in Figure TCK-1 above, Unit 1's NCF and EAF and Unit 2's NCF during the Winter Storm Elliott Period were higher during Winter Storm Elliott that their 6-year highest annual levels. Both Units' NCF and EAF during the storm period far exceeded their 6-year averages. Both Mitchell Units also performed at levels in excess of PJM fleet averages.

9. Both Mitchell Units experienced derates due to operational issues at times during the Winter Storm Elliott Period; however, as demonstrated above, those derates did not materially affect the Mitchell Plant's availability during that period. A "derate" is defined as a decrease in the available capacity of an electric generating unit, commonly due to a system or equipment modification or environmental, operational, or reliability considerations. As demonstrated in Exhibit TCK-1, a significant portion of the derates experienced at both Mitchell Units were required to comply with particulate matter emission limits and the state of West Virginia's 10% opacity limit. The opacity-related derates were not driven by Winter Storm Elliott. Mitchell Unit 1 also had a small 35 MW derate related to a boiler clinker for the duration of the Winter Storm Elliott Period. The remaining derates were caused by frozen coal causing the coal conveyor to trip out, freezing of slurry feed tanks, and a pulverizer damper operation issue. The Winter Storm Elliott-related derates lasted a combined total of only 20.31 of the 240 hours of operation between both Mitchell Units during the Winter Storm Elliott Period.

<u>Big Sandy Plant Fall 2022 Planned Outage</u>

10. Big Sandy Unit 1 began a Planned Outage on September 9, 2022.

11. A Planned Outage is a generating unit outage of a predetermined duration that can last for several weeks and occurs only once or twice a year. Typically, these events consist of a known scope of work and duration that is estimated prior to the outage being scheduled.

12. Planned Outages are scheduled well in advance (months and sometimes even years) due to significant scope, equipment lead time, engineering, and time out of operation. Such outages are planned in conjunction with PJM and with PJM's approval. The Company schedules Planned Outages during the shoulder months attempting to avoid, to the extent practical, multiple units simultaneously in a Planned Outage.

13. It is generally not possible to quickly return a unit that is in a Planned Outage to service if market conditions change. During a Planned Outage, a generating unit is often at least partly dismantled, often with pressure parts (parts that contain steam at very high pressures and temperatures when operating, such as boilers, turbines, etc.) taken apart to be inspected, maintained, and/or replaced. It is very difficult if not impossible to safely and quickly return a unit to service or deviate from the work plan for the outage, particularly when major equipment is disconnected or dismantled for repair at that time.

14. As originally scoped, the fall 2022 Planned Outage at Big Sandy Unit 1 included a generator field out inspection and a possible re-wedge of the Unit's stator.[7] The Company was, in fact, required to completely re-wedge the stator as part of this scope of work. The outage was originally scheduled to be completed on December 4, 2022.

15. On November 7, 2022, the Company extended the Planned Outage at Big Sandy Unit 1 to December 12, 2022, in order to complete the original scope of work, including the stator re-wedge. PJM approved the extension on November 9, 2022.

16. On November 13, 2022, the Company discovered a crack on the generator rotor collection end retaining ring and determined that the retaining ring required replacement prior to returning the Unit to service. The Company was required to replace the retaining ring before restarting the unit to avoid an increased risk of catastrophic generator failure. The Company endeavored to complete the repair within the existing Planned Outage window but ultimately required additional time to do so. On December 2, 2022, the Company requested that the Planned Outage at Big Sandy Unit 1 be extended through December 30, 2022, to complete the retaining ring repair. PJM approved the extension on December 6, 2022.

17. On December 22, 2022, the Company identified a hydrogen seal leak at the exciter during an air leakage test. The Company was required to repair the leak to prevent the risk of a catastrophic failure before the unit could be safely placed back in service. That same day, the Company requested that the Planned Outage be extended through January 5, 2023, to repair the leak. PJM approved the extension on December 28, 2022.

18. During unit start up on January 10, 2023, the Company discovered a condenser leak. The Company was required to repair the leak in order to restart the unit and before the unit could be safely placed back in service. The repair was also necessary to avoid future forced outages. That same day, the Company requested that the Planned Outage be extended through January 14, 2023, to repair the leak. PJM approved the extension on January 11, 2023.

19. Big Sandy Unit 1 was placed back in service on January 14, 2023.

[7] The stator is the stationary part of a rotary system found in electric generators. In an electric generator, the stator converts the rotating magnetic field to electric current.

Conclusion

20. Kentucky Power prudently manages the maintenance of its owned-generation portfolio to maximize the long-term benefits of the assets for its customers. The Company's management of its generation fleet during the Winter Storm Elliott Period was reasonable and prudent.

21. Kentucky Power could not reasonably have done anything during the Winter Storm Elliott Period to increase the Mitchell Units' output. Although the Mitchell Units were derated during Winter Storm Elliott, at no point was either Mitchell Unit unavailable to serve customers. Moreover, the Company cannot legally operate the Mitchell Units in a manner that would violate the particulate matter emission limits and the state of West Virginia's 10% opacity limit. The remaining non-opacity related derates were short in duration but were required to allow for the necessary repairs to be made, some necessitated by the storm, while keeping the Units available. When both Mitchell Units were needed during this extreme event, they were available and performed well, to the benefit of Kentucky Power customers. The Mitchell Plant's operation during the Winter Storm Elliott Period was reasonable and prudent.

22. The Company's actions related to extending the Big Sandy Unit 1 Planned Outage described above were reasonable and appropriate. The Company could not have known that Winter Storm Elliott would occur when it began the Planned Outage. The Company could not have brought the unit back online to serve customers during Winter Storm Elliott without risking a catastrophic failure of the Unit. All of the repairs described above were required to be completed in order to safely operate the Big Sandy Plant. Therefore, it was reasonable to extend the planned outage to ensure the Unit would be in good working order to service customers into the future.

Further, affiant sayeth not.

Timothy C Kerns

Timothy C. Kerns
Vice President of Generating Assets, Appalachian Power Company and Wheeling Power Company

SUBSCRIBED AND SWORN TO BEFORE ME, on the 20th day of July, 2023, to certify which witness my hand and official seal.

Scott E Bishop

Notary Public in and for the Commonwealth of Kentucky

My commission expires: June 24, 2025

SCOTT E. BISHOP
ONLINE NOTARY PUBLIC
STATE AT LARGE KENTUCKY
Commission # KYNP32110
My Commission Expires Jun 24, 2025

Notarial act performed by audio-visual communication

Kern Verification form - revised.docx

DocVerify ID:	831F8FC9-1DA8-4E38-8893-0A8A08AA87B4
Created:	July 20, 2023 08:14:16 -8:00
Pages:	1
Remote Notary:	Yes/ State: KY

This document is a DocVerify VeriVaulted protected version of the document named above. It was created by a notary or on the behalf of a notary, and it is also a DocVerify E-Sign document, which means this document was created for the purposes of Electronic Signatures and/or Electronic Notary. Tampered or altered documents can be easily verified and validated with the DocVerify veriCheck system. This remote online notarization involved the use of communication technology.

Go to www.docverify.com at any time to verify or validate the authenticity and integrity of this or any other DocVerify VeriVaulted document.

E-Signature Summary

E-Signature 1: Timothy C Kerns (TCK)
July 20, 2023 11:52:00 -8:00 [B2D07044B0E0] [167.239.20.121]
tckerns@aep.com (Principal) (Personally Known)

E-Signature Notary: Scott E. Bishop (SEB)
July 20, 2023 11:52:00 -8:00 [08B6BD23D9EB] [167.239.221.101]
sebishop@aep.com
I, Scott E. Bishop, did witness the participants named above electronically sign this document.

DATA REQUEST

KPSC 1_6 Provide a detailed explanation of how Kentucky Power's generating units were operating during Winter Storm Elliott. Include in the response a list and event description in chronological order showing by unit and date any scheduled, actual, and forced outage for the months of November and December 2022.

RESPONSE

Winter Storm Elliott began in the Pacific Northwest on December 20, 2022 and moved east at a rapid pace becoming a bomb cyclone, an area of low pressure that intensifies rapidly, and entering the PJM territory on December 23, 2022. Winter Storm Elliott impacted the PJM territory from December 23, 2022 until December 27, 2022. During that period, none of the Company's generating units were forced from service.

Big Sandy Unit 1 was in its Planned Outage (9/9/22 – 1/14/23) which was extended from its planned end date of 12/12/2022 due to emergent generator repair work discovered during its reassembly. The completion of this work was required so the unit could be returned to service and operated safely and reliably.

Both Mitchell units operated continuously throughout the Winter Storm Elliott period (12/23/2022 – 12/27/2022). At times during that period, each of units' output was reduced (or derated) due to operational issues. Those deratings resulted in Net Capacity Factors (NCF) of 80.3% and 74.1% for Units 1 and 2, respectively and were largely unrelated to the extreme weather.

Table 1 below describes the performance of the Company's generating units during the period.

Kentucky Power Company
KPSC Case No. 2023-00145
Commission Staff's First Set of Data Requests
Dated May 10, 2023

Table 1. KPCo Unit Performance During the 5 day Winter Storm Elliott Period (12/23/2022 - 12/27/2022)

	Equivalent Forced Outage Rate (EFOR)	Equivalent Availability Factor (EAF)	Net Capacity Factory (NCF)
Big Sandy Unit 1	0.0%	0.0%	0.0%
Mitchell Unit 1	13.7%	86.3%	80.3%
Mitchell unit 2	21.6%	78.4%	74.1%

Performance Metric Definitions
Equivalent Forced Outage Rate (EFOR)[1] - The ratio of unit's forced outage hours + derates to the its forced outage hours + service hours expressed as a percentage.
Equivalent Availability (EAF)[1] - The ratio of the unit's available hours - all derate hours to the number of hours in the period.
Net Capacity Factor (NCF)[1] - The ratio of the unit's net generation to it maximum potential output for the period.
[1] Formal definitions and equations for performance metrics can be found in the ***NERC 2023 Data Reporting Instructions - Appendix F***

Attachment KPCO_R_KPSC_1_6_Attachment1 lists the curtailing (derating) events for the period by unit and in chronological order.

Attachment KPCO_R_KPSC_1_6_Attachment2 lists the forced, maintenance and planned outages in chronological order for the months of November and December 2022.

Witness: Robert A. Jessee

	Event Type Code *								
Unit Name	Outages	Curtail.	Event Start	Event End	Event Description	MW Reduction	Period Elapsed Loss (MWH)	Event Number	Event Elapsed Time (Hours)
Big Sandy 1	PO		09/09/22 11:00 PM	01/14/23 11:47 AM	Boiler i/r, Generator Field Out inspection/possible rewedge, Turbine Valve i/r, Corrosion Fatigue i/r, Cooling Tower i/r, ReHeat Attemperator i/r, Gas valve i/r, FD Fan and Motor i/r, High Energy Piping (HEP) i/r, Flow Accelerated Corrosion (FAC) i/r, Core Loop testing.	295	35,448	71	119.98
Mitchell 1		D3	12/22/22 12:00 AM	12/30/22 12:00 AM	Large clinker growing on North side of Boiler	35	4,200	948	119.98
Mitchell 1		D1	12/24/22 06:48 AM	12/24/22 07:06 AM	Reagent slurry feed tanks have frozen level indications and tanks were lower than expected	465	140	949	0.30
Mitchell 1		D1	12/24/22 07:06 AM	12/24/22 07:43 AM	Reagent slurry feed tanks have frozen level indications and tanks were lower than expected	97	60	950	0.62
Mitchell 1		D1	12/24/22 07:43 AM	12/24/22 08:20 AM	Reagent slurry feed tanks have frozen level indications and tanks were lower than expected	465	287	951	0.62
Mitchell 1		D1	12/24/22 08:20 AM	12/24/22 12:00 PM	Reagent slurry feed tanks have frozen level indications and tanks were lower than expected	140	514	952	3.67
Mitchell 1		D1	12/24/22 01:48 PM	12/24/22 07:34 PM	Opacity	80	462	953	5.77
Mitchell 1		D1	12/24/22 07:34 PM	12/25/22 09:00 AM	Opacity	90	1,210	954	13.43
Mitchell 1		D1	12/25/22 10:07 AM	12/25/22 12:31 PM	Frozen lumps of coal causing conveyor trip out outs	135	324	955	2.40
Mitchell 1		D1	12/26/22 12:20 AM	12/26/22 08:29 AM	Opacity	45	368	956	8.15
Mitchell 1		D1	12/26/22 08:29 AM	12/26/22 08:46 AM	Opacity	60	17	957	0.28
Mitchell 1		D1	12/26/22 08:46 AM	12/27/22 12:00 AM	Opacity	85	1,296	958	15.23
Mitchell 1		D3	12/27/22 12:00 AM	12/27/22 01:40 AM	Opacity	85	142	959	1.67
Mitchell 1		D3	12/27/22 01:40 AM	12/27/22 02:02 AM	Opacity	135	50	960	0.37
Mitchell 1		D3	12/27/22 02:02 AM	12/27/22 02:53 AM	Opacity	155	132	961	0.85
Mitchell 1		D3	12/27/22 02:53 AM	12/27/22 04:43 AM	Opacity	185	339	962	1.83
Mitchell 1		D3	12/27/22 04:43 AM	12/27/22 07:22 AM	Opacity	205	544	963	2.65
Mitchell 1		D3	12/27/22 07:22 AM	12/27/22 11:03 AM	Opacity	235	866	964	3.68
Mitchell 1		D3	12/27/22 11:03 AM	12/28/22 12:00 AM	Opacity	245	3,174	965	12.93
Mitchell 2		D1	12/23/22 10:10 AM	12/23/22 10:28 AM	25 Pulv issue	95	29	908	0.30
Mitchell 2		D1	12/23/22 10:28 AM	12/23/22 05:44 PM	25 Pulv issue, could not get dampers to operate	90	654	910	7.27
Mitchell 2		D1	12/23/22 12:07 PM	12/23/22 01:56 PM	Opacity	25	46	909	1.82
Mitchell 2		D1	12/23/22 01:56 PM	12/23/22 02:53 PM	Opacity	50	48	913	0.95
Mitchell 2		D1	12/23/22 02:53 PM	12/23/22 07:22 PM	Opacity	100	448	914	4.48
Mitchell 2		D1	12/23/22 07:22 PM	12/23/22 09:08 PM	Opacity	90	159	915	1.77
Mitchell 2		D1	12/23/22 09:08 PM	12/24/22 02:46 AM	Opacity	150	845	916	5.63
Mitchell 2		D1	12/24/22 02:46 AM	12/24/22 04:41 AM	Opacity	90	173	917	1.92
Mitchell 2		D1	12/24/22 04:41 AM	12/24/22 02:08 PM	Opacity	75	709	918	9.45
Mitchell 2		D1	12/24/22 06:48 AM	12/24/22 07:08 AM	Reagent slurry feed tanks have frozen level indications and tanks were lower than expected	415	138	911	0.33
Mitchell 2		D1	12/24/22 07:08 AM	12/24/22 12:00 PM	Reagent slurry feed tanks have frozen level indications and tanks were lower than expected	210	1,023	912	4.87
Mitchell 2		D1	12/24/22 02:08 PM	12/25/22 12:00 AM	Opacity	90	888	919	9.87
Mitchell 2		D3	12/25/22 12:00 AM	12/26/22 12:00 AM	Anticipated opacity	190	4,565	920	24.00
Mitchell 2		D3	12/26/22 12:00 AM	12/27/22 12:38 PM	Opacity	190	6,968	921	36.63
Mitchell 2		D3	12/27/22 12:38 PM	12/27/22 02:02 PM	Opacity	210	294	923	1.40
Mitchell 2		D3	12/27/22 02:02 PM	12/27/22 03:12 PM	Opacity	230	268	924	1.17
Mitchell 2		D3	12/27/22 03:12 PM	12/27/22 04:08 PM	Opacity	340	317	925	0.93
Mitchell 2		D3	12/27/22 04:08 PM	12/28/22 11:40 PM	Opacity	365	2,871	926	7.85

Event Type *
Outages
FO Forced Outage
MO Maintenance Outage
PO Planned Outage
RS Reserve Shutdown
SF Startup Failure
Note: i/r = inspection and repair
Curtailment
D1 Requires immediate reduction in capacity
D2 Does not require an immediate reduction in capacity but requires a reduction within six (6) hours
D3 Can be postponed beyond six (6) hours, but requires reduction in capacity before the end of the next weekend

Unit Name	Event Type *	Event Start	Event End	Event Description
Big Sandy 1	PO	09/09/22 11:00 PM	01/14/23 11:47 AM	Boiler i/r, Generator Field Out inspection/possible rewedge, Turbine Valve i/r, Corrosion Fatigue i/r, Cooling Tower i/r, ReHeat Attemperator i/r, Gas valve i/r, FD Fan and Motor i/r, High Energy Piping (HEP) i/r, Flow Accelerated Corrosion (FAC) i/r, Core Loop testing.
Mitchell 1	PO	10/07/22 11:00 PM	11/19/22 05:32 PM	Boiler i/r, Precip i/r, Pulverizer/Feeder MATS i/r, Economizer wash, Replace Precip Transformer power cables, Replace SCR XJ s 14,15 and 115, Replace Exit Duct XJ FGX-71009, Water Cannon upgrades, Ovation Evergreen upgrade, Inter-lock testing, HE Piping i/r.
Mitchell 1	RS	11/19/22 05:32 PM	11/29/22 11:45 AM	Reserve Shutdown
Mitchell 1	SF	11/29/22 11:45 AM	11/29/22 06:03 PM	Unable to get firing permissives.
Mitchell 1	MO	12/03/22 01:47 AM	12/08/22 09:18 AM	Economizer tube leak repair
Mitchell 1	FO	12/08/22 11:45 AM	12/09/22 12:00 AM	PH Issues
Mitchell 1	FO	12/09/22 12:00 AM	12/10/22 08:01 AM	due to Urea from Hydrolyzer system entering the Condensate Return System. Samples will be collected and tested once the unit cools. Hydrolyzer will need pressurized to search for potential leaks.
Mitchell 1	FO	12/10/22 01:07 PM	12/13/22 04:30 PM	Due to Primary Superheater Outlet valve . packing blew out. Superheater Bypass Control valve URV 4, controller failed closed due to burned up controller.
Mitchell 1	RS	12/13/22 04:30 PM	12/14/22 02:45 AM	Reserve Shutdown
Mitchell 1	SF	12/14/22 02:45 AM	12/14/22 07:15 PM	Start Failure
Mitchell 1	MO	12/30/22 12:00 AM	01/22/23 05:59 PM	Boiler i/r, Boiler Hydro, Duct repairs, Clinker Removal, IK Soot Blower Repairs, 12 ID Fan Stall margin probe i/r.
Mitchell 2	PO	09/09/22 11:00 PM	12/16/22 02:25 PM	Boiler i/r, Cooling Tower i/r, Low Pressure Turbine "A"&"B" Valve replacement, SCR Catalyst #4 layer replacement, AH Basket i/r, Precip i/r.
Mitchell 2	PO	12/16/22 02:52 PM	12/16/22 03:28 PM	Boiler i/r, Cooling Tower i/r, Low Pressure Turbine "A"&"B" Valve replacement, SCR Catalyst #4 layer replacement, AH Basket i/r, Precip i/r.
Mitchell 2	FO	12/17/22 02:12 PM	12/20/22 04:08 PM	A Bus Relay PA Fan

Event Type *

FO	Forced Outage
MO	Maintenance Outage
PO	Planned Outage
RS	Reserve Shutdown
SF	Startup Failure
Note:	i/r = inspection and repair

Exhibit C

Winter Storm Elliott

Event Analysis and Recommendation Report

July 17, 2023

For Public Use

Contents

Table of Figures

Table of Tables

Executive Summary

Winter Storm Elliott hit the eastern United States over the Dec. 23–25 weekend and tested the reliability of much of the Eastern Interconnection. Precipitous temperature drops and powerful winds caused widespread generator failures and froze up natural gas supplies while driving up electricity demand, leading to power outages in some of PJM's neighbors.

PJM and its members were able to maintain the reliability of the system, serve customers and even support neighboring systems during some periods, which was a significant accomplishment. Specifically, PJM operators were able to avoid electricity interruptions throughout this event. Nevertheless, PJM operators had to implement multiple emergency procedures and a public appeal to reduce energy use to maintain reliability in the PJM footprint serving 13 states and the District of Columbia.

Advanced Planning

As documented in this report, PJM was prepared for the 2022/2023 winter, as well as Winter Storm Elliott, based on the information available, and conducted extensive preparations and communications with members, adjacent systems and the natural gas industry in advance of the storm, in addition to the regular steps PJM takes each year to prepare for winter.

PJM's annual pre-winter analysis indicated that PJM would have enough generation to meet load even under a combination of extreme and unlikely conditions, including pipeline disruptions similar to those previously seen under similar winter conditions, close-to-zero wind/solar generation, high generation outages and extreme weather. Despite numerous refinements to both the capacity market rules and winter preparation requirements that came out of the 2014 Polar Vortex, Winter Storm Uri in 2021, and other recent examples of increasingly extreme weather patterns, Winter Storm Elliott created a convergence of circumstances that strained the grid.

PJM's load forecasts for Dec. 23 and Dec. 24 were approximately 8% under the actual peak. The modeling challenges that resulted in this under-forecast are detailed in this report. Given the operational uncertainty, PJM operators scheduled prudently on both days (in excess of the actual load plus reserve requirements).

Operations and Generator Performance

Elliott's rapidly falling temperatures coincided with a holiday weekend that combined to produce unprecedented demand for December. This was further complicated by unexpectedly high resource unavailability and/or failures to perform.

On the first day of the storm, Dec. 23, the stress on PJM's neighbors began to signal extreme conditions headed for the region PJM serves. The Southwest Power Pool (SPP) set a new winter peak that day; the Tennessee Valley Authority (TVA) experienced the highest 24-hour electricity demand supplied in its history. PJM exported energy to TVA, Duke Carolinas and Duke Energy Progress before having to curtail most exports during peak conditions in the face of emergency conditions.

PJM's forecast for Dec. 23 was about 127,000 MW, and load came in at about 136,000 MW. This demand level is approximately 25,000 MW above a typical winter peak day. In preparation for this day, PJM had approximately 158,000 MW of operating capacity based on what was scheduled in the Day-Ahead Market plus available generation able to be called upon in real time. PJM was able to meet this load with the help of a Maximum Generation Action and Demand Response. Looking to Dec. 24, the coldest day of the weekend, PJM operators decided to schedule conservatively in terms of reserves (the electricity supplies that are not currently being used but can be quickly available in the case of an unexpected loss of generation). Based on the information it had received from generation resources, PJM anticipated that approximately 155,700 MW of generation should have been available for Dec. 24.

Complications arose on Dec. 24 resulting from the unanticipated failure of generation resources that were called into the operating capacity on that day. At one point, almost a quarter of the generation capacity – 47,000 MW – was on forced outages. While generators are required to provide updates on their operating parameters, including operating status, ramp times and fuel availability, in 92% of generator outages, PJM operators had an hour's notice or less – in most cases, PJM was informed of outages when dispatchers called generators to request them to turn on.

When examined over the entire generation fleet, gas generators accounted for 70% of the outages on Dec. 24. Most outages were caused by equipment failure likely resulting from the extreme cold, though broader issues of gas availability also contributed to the outages.

Market Outcomes

Elliott was the first wide-scale use of PJM's Capacity Performance rules, which were introduced in 2016 as a market tool to incent generator performance following the 2014 Polar Vortex – a similar event characterized by extreme cold weather and high forced outage rates. The high outage rates for generators during Winter Storm Elliott resulted in substantial Non-Performance Charges that are part of Capacity Performance rules. As of this report, PJM estimates there are approximately $1.8 billion in Non-Performance Charges based on the current rules. Those charges are allocated to suppliers that exceeded their committed capacity level.

Outreach

PJM's communications and government policy teams relayed critical situation updates in a timely fashion; short operational update videos from PJM leadership were used to reach a wide audience by television, print and digital media, while external-facing personnel used the same videos to update their important state and federal contacts. The Call for Conservation was widely amplified by Transmission Owners, regulators and even governors' offices on social and traditional media, and PJM is looking at strategies to build on that effective partnership.

Recommendations Overview

The analysis of PJM's experience during Winter Storm Elliott confirms the decisions by PJM planners and operators in preparing for and navigating through the storm, including communications, emergency procedures, and the scheduling and management of interchange in support of the Eastern Interconnection. In addition, the capacity market's performance rules were implemented as written in the Tariff and manuals.

At the same time, Elliott also provides some clear lessons for PJM and its stakeholders that drive the 30 recommendations contained in this report. These recommendations are broadly focused on:

- Addressing winter risk with enhancements to market rules, accreditation, forecasting and modeling
- Improving generator performance through winterization requirements, unit status reporting and testing/verification
- Tackling long-standing gaps in gas-electric coordination, including timing mismatches between gas and electric markets, the liquidity of the gas market on weekends/holidays, and the alignment of the electricity market with gas-scheduling nomination cycles
- Evaluating how the Performance Assessment Interval (PAI) system of rewarding or penalizing generator performance is impacted by exports of electricity to other regions, whether excusal rules can be simplified, PAI

triggers need to be refined, and if the contributions of Demand Response and Energy Efficiency are accurately valued

- Pursuing opportunities with Generation Owners, other members and states to improve education, drilling and communication regarding PJM's emergency procedures, Call for Conservation and PAIs

Many of these recommendations, as indicated in the chart below, are currently being developed through the Critical Issue Fast Path – Resource Adequacy process or through other forums.

Recommendations

ID	Category	Recommendation	Type	Status
1	Resource Performance	Evaluate needed enhancements to the generator Cold Weather Checklist and the Cold Weather Operating Limit reporting practices used to prepare for cold weather to help improve generator cold weather performance in the future. Incorporate lessons learned as necessary to improve these checklists to include validation procedures. Evaluate reasons why the information provided by Curtailment Service Providers regarding their ability to curtail load was not accurate. Incorporate lessons learned as necessary to include validation procedures.		Under internal PJM review
2	Emergency Procedures	Reinforce PJM and member steps and expectations in Manual 13 for operation during emergency procedures through additional training and manual clarifications. Specific focus on: • Existing actions in Cold Weather Advisory and Cold Weather Alert regarding winterization and staffing procedures • Criteria, sequencing, and communication of alerts, warnings and actions • Consideration of potential opportunities to clarify member expectations in M-13		New
3	Operating Reserves	Evaluate triggers for increasing the Operating Reserve Requirements in advance of the operating day based on risks imposed by projected extreme temperatures, unusual temperature changes, load uncertainty, solar/wind uncertainty, generator performance uncertainty, OFOs, etc.		Pending internal process change
4	Load Forecast	Evaluate opportunities for improvements to the extreme weather load forecast processes and methodology with independent and peer analysis.		Under internal PJM review
5	Unit Parameters	PJM will provide additional training relating to the use of Parameter Limited Schedules (PLS) and price schedules. The focus of the training will include the time to start parameters for the various schedule types and the use of PLS parameters. The intended training audience is for anyone managing and updating the PLS and price schedules.		New

ID	Category	Recommendation	Type	Status
6	Unit Status	Evaluate the Temporary Exception and Real-Time Value processes that require gas-fired generators to either update their operating parameters, or confirm that no updates are needed, when Cold Weather Advisories, Alerts, Conservative Operations, or pipeline OFOs are issued that may impact their ability to procure gas outside of standard nomination timelines. Make improvements to ensure accurate offer information from generation resources.		Under discussion at the Electric Gas Coordination Senior Task Force (EGCSTF)
7	Gas Electric Coordination	Develop solutions to address near-term gas generator unavailability resulting from gas and electric market timing issues, particularly during periods of cold temperatures and high winter demand.		Under discussion at the EGCSTF
8	Gas Electric Coordination	Explore opportunities to increase alignment between the scheduling of natural gas-fired resources with nomination cycles.		Under discussion at the EGCSTF
9	Gas Electric Coordination	Evaluate the current multi-day commitment process for use during expected critical high demand periods so as to analyze the costs and benefits of providing greater certainty of fuel supply procurement through the critical period, with a focus on weekends when the gas commodity market can be less liquid.		Under discussion at the EGCSTF
10	Gas Electric Coordination	Provide recommendations to FERC to investigate weekend gas supply liquidity to facilitate increased gas procurement ability during weekend/holiday periods.		Under discussion at the EGCSTF
11	Gas Electric Coordination	Work with states to discuss opportunities to increase prioritization of natural gas for usage in electricity production for resources behind LDCs.		Under discussion at the EGCSTF
12	Gas Electric Coordination	Explore opportunities to better align submitted offer data to true availability of natural gas resources.		Under discussion at the EGCSTF
13	Gas Electric Coordination	Evaluate the ability to include fuel-specific information in the capacity accreditation model. Consider including items such as: 1. Different levels of fuel security, including dual-fuel capability, firm gas and non-firm gas 2. Minimum requirements for onsite fuel		Under discussion in the CIFP process
14	Unit Status	Evaluate options for requiring generators to provide procurement information to PJM in real time and day ahead to provide greater situational awareness to PJM regarding the ability and timeliness of procuring fuel.		Under discussion at the EGCSTF
15	Voltage Reduction	Review and update, as necessary, the expected load reduction achieved during a Voltage Reduction Action due to changing composition of load. This recommendation specifically focuses on the Voltage Reduction Summary table in Manual 13.		New

ID	Category	Recommendation	Type	Status
16	Reserve Performance	Evaluate opportunities to increase the performance of Synchronized Reserves to achieve the desired response. This may include levels procured, procurement practices, compensation or other aspects of the Reserve Market design.		Stakeholders notified that PJM's reserve requirement will be increased to 1.3 times the largest contingency MW effective May 19 until further notice
17	Reserve Pricing and Penalties	Evaluate the current Reserve Market design to ensure reserve products, estimated reserve capabilities on resources, procurement practices and timelines, quantities procured, performance incentives, etc., align with operational needs and that prices and performance incentives are similarly aligned.		Issue charge planned for August
18	Cost Offer Verification	Distribute training on the Cost Offer Verification process to members (standard email or similar notification) before cold weather events and send alerts to update MIRA ahead of time.		New
19	CIFP	Evaluate how risk modeling in the reliability analysis used in the capacity market can be improved to better account for the drivers of reliability risk experienced in the winter.		Under review at the CIFP
20	CIFP	Evaluate reforms to capacity market rules and incentives to improve the performance of resources, including: • Review the Capacity Performance construct, with consideration of financial risks. • Strengthen capacity accreditation and qualification criteria (e.g., winterization/fuel assurance). • Evaluate opportunities to improve testing rules to complement assessments during actual reliability events, including frequency of the tests, defined guidelines for test success/failure, and penalties for test failure. • Evaluate current practices in other ISO/RTOs for requiring generator inspections and implement any best practices.		Under review at the CIFP
21	CIFP	Evaluate opportunities to align the incentives from the capacity market via PAIs with real-time operating conditions, particularly with regard to PAI triggers.		PJM filed changes to the PAI triggers on May 30. Discussions will continue as part of the larger reforms in the CIFP process.
22	CIFP	Evaluate if and how exports should be accounted for in the balancing ratio.		Under review at the CIFP
23	CIFP	Reevaluate what happens in the scenario that a resource has not submitted a valid offer.		Under review at the CIFP
24	CIFP	Explore opportunities to refine and simplify excusal rules to reduce manual and case-by-case review processes.		Under review at the CIFP

ID	Category	Recommendation	Type	Status
25	CIFP	Review the M&V calculations of Energy Efficiency and Demand Resources for PAIs to assess if the determination of actual performance and bonus accurately reflects the reliability benefit provided.	Market Construct Process Change or Addition	Under review at the CIFP
26	CIFP	Evaluate the performance issues regarding NRBTMG, and provide recommendations on enhancing its performance or altering its participation in the capacity market.	Market Construct Process Change or Addition	Reviewed at the May 8 DISRS Stakeholder group
27	CIFP	Explore opportunities for further education on PAIs, such as providing periodic training sessions.	Training and awareness improvement	In Progress
28	Call for Conservation	Evaluate opportunities to enhance Public Notification Language in Attachment A of Manual 13 regarding Call for Conservation to better direct the appeal to all customers, not just residential. Establish a process for annual review of state alert contacts, and explore additional opportunities to further amplify PJM's message through state communication channels, up to and including Emergency Alert Systems.	Process Improvement	In Progress
29	Outreach	Operations, Corporate Communications and SGP will seek ways to enhance communications, specifically looking at timeliness, relevance and clarity of information provided along with curating and updating of appropriate contacts for each audience and channel for messaging.	Process Improvement	In Progress
30	Drills & Exercises	Operations, Corporate Communications and SGP will also strengthen their periodic drilling with states, Transmission Owners and other members by: 1) Finding opportunities to include states in PJM crisis exercises; 2) Providing education on PJM emergency procedures and Call for Conservation during summer and winter operations drills; 3) Following up with parties not represented at drills to make sure they are aware and contacts are up to date.	Training and awareness improvement	In Progress

Legend for Type

Operational Change

Market Construct Process Change or Addition

Process Improvement

Training and awareness improvement

About This Report

Purpose

The purpose of this analysis and subsequent report is to review the events up to and during Winter Storm Elliott, assess the actions of PJM and its members during those times, and look for lessons learned and associated recommendations to help improve grid reliability.

Analysis Process

The review process performed for this report was driven by the Human Performance and Operating Experience (HP&OE) program at PJM. The HP&OE program promotes excellence in human performance through behaviors that support reliable grid operations, fair and efficient energy markets, and infrastructure planning. The goals of this program are to:

- Reduce the frequency and impact of human error
- Share and learn from internal and external events
- Analyze events to identify corrective actions to prevent and reduce impacts of adverse events
- Ensure that processes and procedures are executed correctly to achieve the desired results

The fundamental aspects of the HP&OE program are:

- **Prevention:** Reduce errors that lead to events
- **Detection:** Identify potential issues across the organization
- **Correction:** Learn from events through event analysis and completion of remedial actions

To conduct this review and event analysis, PJM employed the Learning Teams analysis tool. Learning Teams are utilized in the industry as a collaborative event analysis best practice because it focuses on bringing people together to better understand an event with the basis on learning and identifying successes and improvements.

PJM conducted multiple different focused area Learning Team sessions with subject matter experts and independent participants across various areas of PJM to allow for open and collaborative discussions. The Facilitation Team followed a structured and consistent methodology with a focus on the event itself, and additionally on the timeline and decisions leading into the event, which allowed all members of the team to share their perspective. From the Learning Team sessions, successes and opportunities for improvement were identified that lead to recommendations for future analysis of enhancements to rules and procedures. The recommendations from PJM's Learning Team's sessions on Winter Storm Elliott are contained in this report. The recommendations are then tracked through the HP&OE program until they are resolved.

Organization of This Report

This report outlines the operational preparations that PJM takes in advance of winter generally, and took for Winter Storm Elliott during the Dec. 23–25 holiday weekend specifically, including emergency procedures, communications with members and forecasting. It documents the operating conditions PJM operators faced and the actions they took, and it details the working of the PJM markets just before and during the storm. The Conclusion summarizes the processes and forums that will be used to act on the set of recommendations. For definitions of industry terms, consult the [PJM Glossary](#) on PJM.com.

Advance Preparations

Each year, PJM performs winter readiness assessments and exercises in advance of the cold weather months. These assessments include power flow analyses that simulate potential conditions on the power system for expected and extreme winter conditions, as well as a capacity "waterfall chart" to determine if adequate capacity is expected to be available based on various stress cases. This analysis is known as the Winter Operations Assessment Task Force Study.

In 2021, in light of the severe cold weather issues experienced in Texas during February 2021, PJM initiated an analysis that resulted in numerous additional improvements to its winter preparedness efforts. Those improvements included approving rules to assist Transmission Owners (TOs) in identifying and prioritizing service to critical facilities in emergencies, prohibiting Load Management programs from including any critical gas infrastructure, further improving information sharing with the natural gas industry, and confirming that TOs were prepared to rotate outages if load shedding was required.

PJM also collects data on generating resource fuel inventory, supply and delivery characteristics, emissions limitations, and minimum operating temperatures via the Seasonal Fuel Inventory and Emissions Data Request (PJM Manual 14D, Section 7.35) and also via Periodic Fuel and Emissions Data Requests issued as needed throughout the season. Furthermore, PJM validates that Generation Owners have adequately prepared for winter by requiring that they confirm they have completed the Cold Weather Preparation Guideline and Checklist.

Also, as a result of increasing supply chain risks to fuel deliveries, PJM initiated a weekly fuel and non-fuel consumables data request for all generators that utilize coal or oil as their primary or backup fuel. Capturing this data more frequently allows PJM to better understand any fuel supply, supply chain or transportation issues that could impact generators. Due to the continued concern with supply chain issues, the practice was extended through all of 2022, including the winter of 2022. Current system conditions do not necessitate this weekly data request but will be re-initiated, if necessary. These rule changes provided better visibility into generators' supply of fuels and other material critical to their operation and enhance the flexibility those generators need to rebuild their supplies when facing shortfalls beyond their control. The data requests did not identify any issues.

As described above, PJM prepares extensively for the peak winter season, including the following key annual activities:

- PJM Winter Operations Assessment Task Force Study
- Generation Resource Cold Weather Preparation Guideline and Checklist
- Cold Weather Resource Operational Exercise
- Pre-Winter Emergency Procedures Drill
- PJM Winter Readiness Meeting

This section details PJM's processes leading up to the storm, including regular winter preparations, issuing Cold Weather Advisories and Cold Weather Alerts, and other activities taken during the week of Dec. 18 in advance of Dec. 23 and Dec. 24.

PJM Winter Operations Seasonal Study

The PJM Operations Assessment Task Force (OATF) consists of representatives from PJM and PJM Transmission Owners. This team, under the direction of PJM, conducts seasonal studies for the summer and winter periods. Each study analyzes the PJM system with the transmission and generation configuration approximating the expected conditions for that study period.

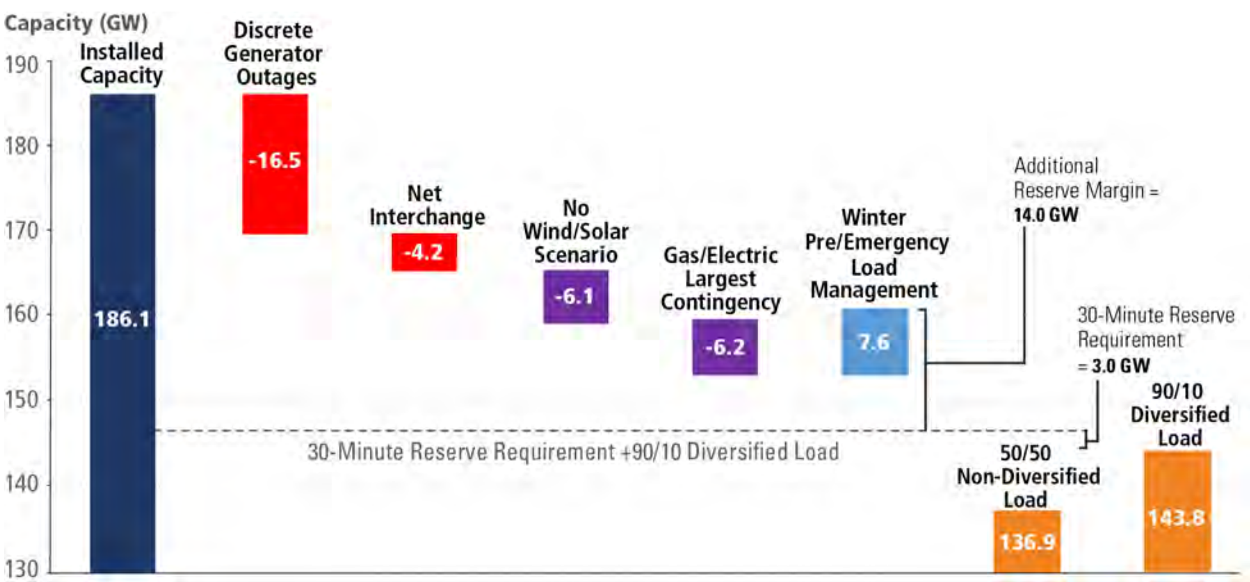
The study conditions include forecasted demand based on forecast weather and estimated outages, as well as a series of more extreme scenarios, including, but not limited to:

- External contingencies that could impact PJM reliability
- The loss of more than one bulk electric system (BES) element (N-1-1 relay trip conditions)
- A Maximum-Credible Contingency Analysis (e.g., loss of a substation, loss of multiple lines in a common right of way)
- An import capability analysis
- An extreme (90/10) load forecast study
- A solar and wind generation sensitivity study
- A gas pipeline disruption study

The results of this analysis indicated that there was sufficient generation for the 2022/2023 winter period to meet the demand under all studied conditions. The process for conducting the OATF study is documented in PJM Manual 38, Operations Planning, Attachment A.

As shown in **Figure 1**, PJM projected that more than adequate capacity should have been available for the 2022/2023 winter period.

Figure 1. Projected Capacity for 2022/2023 Winter Period



The OATF study is reviewed at the System Operations Subcommittee (SOS) and the Operating Committee (OC).

Generation Resource Operational Exercise

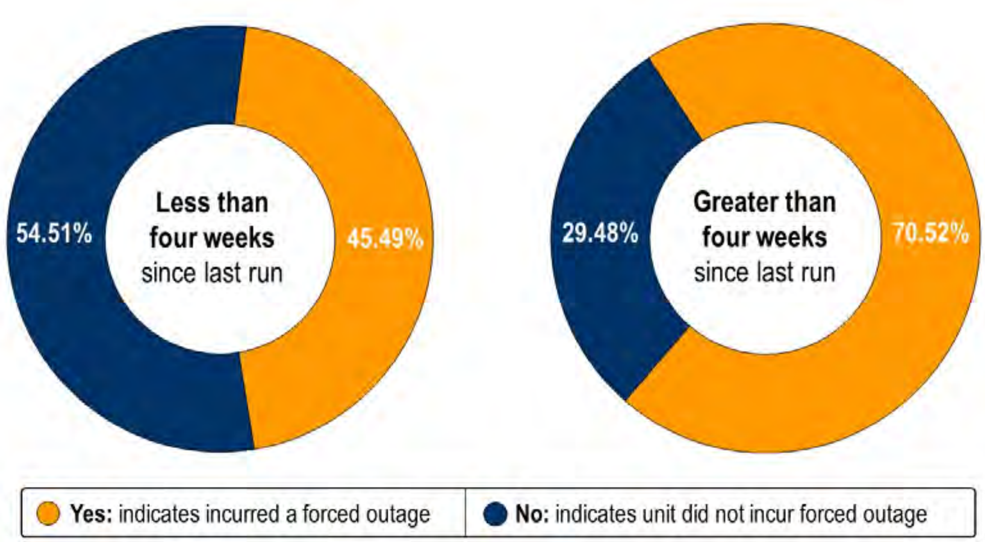
Following the 2014 Polar Vortex, PJM made several changes to its Cold Weather Operating Procedures, including establishing a Generation Resource Operational Exercise Program and a Generation Resource Cold Weather Checklist. The Generation Resource Operations Exercise Program is intended to enhance unit performance during cold weather operations and encourage generating units to be prepared for extreme cold weather and can start and run on alternate fuels, if necessary. The exercise assists in the identification and correction of start-up and fuel-switching problems (PJM Manual 14D, Section 7.5).

PJM also recommends that Generation Owners conduct an operational exercise prior to the onset of cold weather to validate a unit's cold weather operations. Specifically, PJM recommends that Generation Owners self-schedule any of their resources that have not operated in the eight weeks leading up to Dec. 1 to determine whether they are capable of reliably operating on both primary and alternate fuel and responding to PJM's dispatch instructions. Generation Owners are requested to submit an informational eDART ticket with a cause of "Cold Weather Preparation Exercise" to document that the generation resource has been scheduled to operate under the cold weather operational exercise.

The charts in **Figure 2** present the forced outage rates during Elliott for units that had not run in the weeks leading up to the event. A four-week time period was used as the cutoff for the performance analysis. Those units that had not run in more than four weeks had higher forced outage rates. This data demonstrates that generators that had run in the few weeks prior to Winter Storm Elliott performed better than those that did not. As a result, PJM believes consideration should be given to making this currently recommended exercise a requirement.

When reviewing generator performance for units that did not operate for four weeks prior to Winter Storm Elliott, 70.5% of units incurred a forced outage during the event. This data supports continuing or expanding the Generation Resource Operational Exercise described in PJM Manual 14D, Section 7.5.1, which is currently recommended, but not required for Generation Owners to perform.

Figure 2. Forced Outages Versus Last Run Time



Generation Resource Cold Weather Preparation Checklist

Similarly, the Generation Resource Cold Weather Checklist (presented in PJM Manual 14D, Section 7.5 and Attachment N), or a similar one developed and maintained by the Generation Owner, should be used annually prior to the local

National Oceanic and Atmospheric Administration (NOAA) first frost date to prepare its generation resources for extreme cold weather event operations.

This checklist includes verification by Generation Owners that they have performed everything from increasing staffing for weather emergencies to performing required maintenance activities to prepare equipment for winter conditions. This checklist was first developed and issued to Generation Owners in 2014 and is updated annually as new industry lessons learned are published by NERC and others. For this winter, the checklist was updated to require information about a generating unit's cold weather operating limits. This was added as a result of the lessons learned from Winter Storm Uri.

The checklist identifies and prioritizes components, systems and other areas of vulnerability that may experience freezing problems or other cold weather operational issues such as safety staffing, equipment preparation, fuel preparation and environmental preparation; as well notes the actions to be taken when cold weather is forecast and actions during cold weather. Between Nov. 1 and Dec. 15 of each year, the Generation Owner is required to verify via eDART that the represented generation resources have completed the items on the checklist, or a substantially equivalent one developed by the Generation Owner. Ahead of Winter Storm Elliott, 99% of the generation resource owners in the PJM region verified that they completed the items on the Generation Resource Cold Weather Preparation Checklist or equivalent.

Table 1 summarizes the Cold Weather Checklist responses:

Table 1. Cold Weather Checklist Response Summary 2022

	Unit Count	Installed Capacity (MW)
Yes – Using Generation Owner Equivalent Guideline and Checklist	1,043	179,332
Yes – Using PJM Guideline and Checklist	270	16,974
No	52	1,262
No Response	37	238

The Cold Weather Checklist is discussed in the System Operations Subcommittee (SOS), Operating Committee (OC) and Market Reliability Committee (MRC). Additional information on generation performance is presented in the Operating Day section of this report.

Transmission Outage Deferrals

Transmission outage deferrals are an approved measure to promote the ability to transfer power across the RTO and promote an abundance of caution to be as prepared as possible. When PJM issues a Cold Weather Alert, PJM recalls/cancels non-critical transmission maintenance outages. Specifically, the following transmission outages were deferred or returned to service early:

- BLACKOAK-HATFIELD (eDART # 1053409 12/19 – 12/22) outage request was denied due to a conflict and cold weather.
- Two major outages returned to service early on Dec. 23. PJM was in close coordination with the TOs for the return of Mt. Storm-Valley 500 kV and the Malizewski-Marysville 765 kV lines.

Due to emergency procedures and multiple day-ahead outage approval processes, these lines were requested to be in service for Dec. 23.

Cold Weather Advisory

In advance of the mandatory North American Electric Reliability Corporation (NERC)[1] Winterization Standard becoming effective on April 1, 2023, PJM established the Cold Weather Advisory. A Cold Weather Advisory provides an early notice that forecast temperatures may call for a Cold Weather Alert. The early notification of an Advisory is intended to provide PJM members ample time to gather information required by NERC standards EOP-011, Emergency Preparedness and Operations, IRO-010 RC Data Specification and Collection, and TOP-003 Operational Reliability Data. Members are to take any necessary precautions to prepare generating facilities for cold weather operations. PJM attempts to issue the advisory as far in advance as possible, typically within three to five days, but given fluctuating and changing weather forecasts, advisories could be issued up to 24 hours in advance.

Members are expected to perform the following actions upon the issuance of a Cold Weather Advisory:

- Prepare to take freeze protection actions, such as erecting temporary windbreaks or shelters, positioning heaters, verifying heat trace systems, or draining equipment prone to freezing.
- Review weather forecasts to determine any forecasted operational changes and notify PJM of any changes.
- Update Markets Gateway by entering unit-specific operation limitations associated with cold weather preparedness, including the following limitations:
  - Generator capability and availability
  - Fuel supply and inventory concerns
  - Fuel switching capabilities
  - Environmental constraints
  - Generating unit minimums (design temperature, historical operating temperature or current cold weather performance temperature as determined by an engineering analysis)

PJM conducted a Cold Weather Advisory drill on Dec. 16, 2022. In advance of the drill at the December OC and the SOS meetings, PJM reviewed the objective of the upcoming drill and the expected member actions to be performed during the drill.[2]

Pre-Winter Emergency Procedures Drill

Pursuant to PJM Manual 13, PJM conducts emergency procedure drills prior to every summer and winter that include PJM, Generation Owners and Transmission Owners, and are focused on capacity shortage events. The drill encourages all entities to be familiar with the required actions and communications required for each emergency procedure, up to and including load shed action, as specified in PJM Manual 13, Emergency Operations.

On Nov. 3, 2022, PJM conducted the 2022 Winter Emergency Procedures Drill, testing established procedures for capacity shortages in accordance with conservative operations. Participants included PJM Operations, Dispatch staff and personnel from PJM Corporate Communications/State Government Policy, Local Control Centers and Market Operations Centers.

[1] NERC is a not-for-profit international regulatory authority whose mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid. NERC develops and enforces NERC Reliability Standards, which define the reliability requirements for planning and operating the North American bulk power system.
[2] Cold Weather Advisory Process, PJM System Operations Subcommittee, Dec. 2, 2022.

The following emergency procedures were implemented in the simulation stage of the drill: Cold Weather Alert, Low Voltage Alert, Maximum Generation Emergency Alert, Unit Startup Notification Alert, Primary Reserve Alert, and a Voltage Reduction Alert. All emergency procedure warnings and actions were issued as part of the drill to encourage participants to properly notify government agencies and to exercise internal communications for each member company.

Information about the drill scenario is contained in a packet sent to external participants and in a script for PJM staff. PJM also offers an eLearning module each year in support of the drill. This online training course, available via the PJM Learning Management System on the PJM website, provides an overview of the emergency procedures that participants may encounter during the drill exercise.

The plans for the drill are reviewed at the Dispatcher Training Subcommittee (DTS), the SOS and the OC.

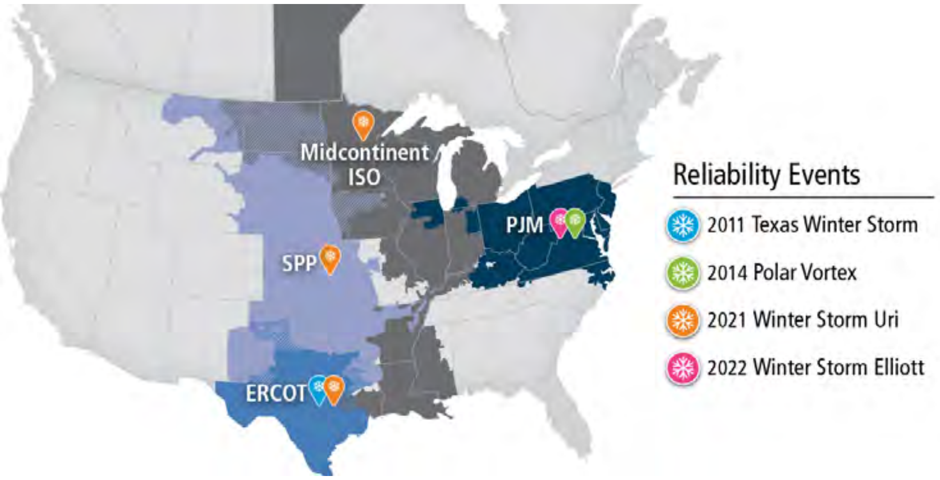
Reliability Analysis Used in the Capacity Market

PJM performs several reliability studies that inform the clearing of the capacity market.

- Installed Reserve Margin (IRM) Study – Study run by PJM that determines the amount of reserves beyond the peak load necessary to maintain a Loss of Load Expectation (LOLE) of one event in 10 years
- Capacity Emergency Transfer Objective (CETO)/Capacity Emergency Transfer Limit (CETL) Studies – Studies run by PJM to determine if the transmission system is capable of delivering enough energy to Locational Deliverability Areas (LDA) to meet reliability targets
- Accreditation – Calculation performed by PJM to determine how much capacity a resource can sell as a percentage of its nameplate capacity

These studies all assume that the reliability risk PJM may face aligns with peak loads, which typically occur in the summer. The assumption behind coinciding reliability risk with peak loads is that if enough capacity is scheduled for the expected peak load, it will also be sufficient for all other hours in the year. However, recent history in PJM and other RTO/ISOs indicates that reliability risk also occurs outside of the peak load and may be trending away from the peak to something else. Figure 3 presents the recent reliability events outside the peak load periods.

Figure 3. Recent Reliability Events



Finding the causes behind these events is important to determine how PJM's reliability risk modeling may need to be adjusted to better capture the likelihood, severity and patterns of risk. PJM and stakeholders are already working on identifying and modeling these new risks.

PJM Winter Readiness Meeting

PJM also conducts an internal, cross-divisional meeting each fall to review each PJM department's preparedness for winter operations. It includes discussions and presentations by PJM's Operations, Markets and Planning divisions. The following topics are addressed in these cross-divisional meetings:

- Weather and load forecast outlook
- Review of winter OATF study (including base case parameters, peak load study results and sensitivity studies)
- Potential gas/electric concerns for upcoming peak period
- Interconnection projects update (including key project upgrades and delays, generation additions and retirements, review of additional reactive resources coming online, generation preparation, outage and performance updates)
- Review of NERC Standard FAC-014, Requirement 6, list of multiple facility contingencies (if any) that result in stability limitations
- Review of any specific concerns or questions from PJM's Dispatch, Reliability Engineering and Markets personnel

Preparations Ahead of Winter Storm Elliott

In preparation for Winter Storm Elliott, PJM performed the established load forecast planning process, issued Advisories and Alerts, and coordinated activities with both the adjacent systems and the natural gas industry. PJM also planned for the commitment of resources needed to meet the Dec. 23 and Dec. 24 operating days' demand and reserve requirements.

Load Forecast Planning Process

PJM uses a vendor tool to view forecast weather conditions up to 14 days out. At six days out, PJM begins to receive hourly weather forecast data from three separate vendors for 28 weather stations dispersed throughout the PJM region. This data is visualized in a heat map tool used by PJM system operators and engineers. **Figure** 4 presents a sample of the heat map tool for Feb. 2 and Feb. 3, 2023. This is an example of a wintertime heat map and does not present the actual temperatures from Winter Storm Elliott.

Figure 4. PJM Heat Map Tool Example

2023 — HOUR ENDING

Area	Friday, Feb. 2, 2023																
	07	08	09	10	11	12	13	14	15	16	17	18	19	20	21	22	23
COMED	-2	-1	0	1	3	5	7	8	9	9	8	7	6	7	7	8	8
	10	10	10	10	9	8	8	7	7	6	5	5	4	4	5	6	7
AEP	18	16	17	17	18	19	20	20	21	21	20	18	18	17	16	16	15
	12	12	12	12	12	12	13	13	12	12	11	10	9	7	6	5	4
FE	14	12	12	13	13	14	14	14	15	15	14	14	13	12	13	12	12
	13	13	13	13	14	14	15	14	14	13	12	11	10	8	8	7	6
DPL	17	17	16	17	18	19	20	21	21	21	20	19	18	18	17	16	16
	12	12	12	12	12	12	12	12	12	12	10	9	7	6	5	5	4
EKPC	23	22	23	25	26	28	29	30	31	31	29	28	26	24	23	23	22
	10	9	9	10	9	9	9	9	9	9	8	7	5	5	5	5	4
DEOK	20	19	18	20	21	22	24	24	24	24	23	22	21	20	19	18	17
	10	10	10	11	11	11	11	11	11	10	10	7	6	6	5	4	4
AP	20	19	18	18	19	19	20	19	20	19	18	16	15	15	14	14	14
	14	14	14	15	15	16	16	16	16	15	14	13	12	11	10	9	8
DUQ	15	13	12	13	14	14	15	15	15	15	14	12	11	11	11	10	10
	13	13	14	14	15	15	15	15	15	14	13	12	10	9	9	8	7
PJM	30	28	27	27	27	26	25	25	25	24	22	21	20	19	19	18	17
	16	16	16	17	18	18	19	19	19	19	18	16	16	15	15	15	14
DOM	37	36	36	36	36	36	35	35	35	34	33	30	29	27	25	24	23
	11	13	14	15	16	16	16	16	16	15	15	14	13	12	12	12	12
NY	29	28	27	26	26	26	26	24	23	22	20	19	18	17	16	15	13
	19	19	20	20	21	21	21	21	21	21	20	20	20	20	19	19	19

Area	Saturday, Feb. 3, 2023														
	00	01	02	03	04	05	06	07	08	09	10	11	12	13	14
COMED	9	9	9	10	11	11	13	14	16	19	22	25	28	31	33
	7	7	8	9	10	11	12	13	14	14	15	16	16	17	17
AEP	15	14	14	14	13	14	15	15	16	18	22	25	28	31	33
	4	4	5	5	6	6	7	8	8	10	11	12	12	13	13
FE	11	11	11	11	10	10	11	12	13	15	18	21	24	26	29
	5	5	5	6	6	7	8	9	9	11	12	13	13	14	14
DPL	15	15	15	15	15	15	16	16	17	20	23	26	30	33	35
	4	4	5	6	7	8	9	10	12	13	14	15	16	16	16
EKPC	22	22	21	21	21	21	21	21	23	27	31	35	40	43	45
	4	4	4	5	5	5	5	6	7	8	9	10	11	12	12
DEOK	17	17	16	16	16	16	16	17	18	21	25	30	34	38	41
	4	4	5	5	6	6	7	7	8	9	10	11	12	12	13
AP	13	13	12	11	11	11	11	11	12	15	18	21	24	26	29
	7	7	7	6	6	5	5	5	5	6	6	8	8	9	9
DUQ	9	9	8	8	8	8	8	8	10	12	15	18	21	23	27
	6	6	5	5	5	5	5	6	6	7	8	9	9	10	10
PJM	16	15	15	14	13	14	13	14	16	18	20	22	24	25	27
	13	14	13	12	11	10	9	8	8	7	7	7	8	8	8
DOM	22	22	21	21	20	19	19	19	21	24	26	28	31	32	33
	11	11	10	9	9	8	7	6	6	5	5	6	6	6	7
NY	13	13	12	11	10	10	9	10	12	13	16	18	21	23	24
	19	19	18	17	17	16	15	14	13	12	12	11	11	12	12

PJM's forecast team and Dispatch leadership also receive detailed weather forecast reports from vendors at various time horizons warning of extreme weather conditions. The PJM forecast team reviews and synthesizes data from all of these sources and delivers daily verbal reports on upcoming weather at the daily Dispatch morning meeting. The PJM forecast team supplements this communication with email summaries and dialogue with PJM system operators.

The load forecast is first performed six days out using a performance-weighted average of the three weather vendor forecasts as inputs. A suite of models trained on three years of historical data generate separate load forecasts that are then combined into one ensemble forecast using another weighted average system. Both the ensemble forecast and individual model forecasts are updated each hour as load actuals and updated weather forecast data is received.

To create the next-day load forecast, PJM Operations support staff reviews weather conditions and recent load forecast performance each day, then integrates this information with known strengths, weaknesses and biases of each model to identify adjustments to the forecast. The support staff then communicates the recommended adjustments to Dispatch, and the two groups collaborate to finalize the forecast. Extra attention is given to holidays, where the models have increased forecast error due to closures of schools and businesses and altered human behavior. Starting at least two days out, the team analyzes model error and weather conditions from that holiday in previous years, then calculates adjustments to counter repeated model biases.

The relationship between load and temperature can change with time, as behind-the-meter solar, data centers, and new types of appliances are connected to the system. PJM monitors these changes, continually evaluates load patterns to assess impacts, and retrains and enhances the models, as needed. Staff analyzed electric heating statistics from the Energy Information Administration and determined that there does not appear to be a significant transition to electric heating in the PJM footprint that would have caused under-forecasting of winter load.

The PJM Operations staff conducted the following load forecasting activities in advance of the Winter Storm Elliott event:

Date	PJM Team	Activity
Mon. Dec. 19:	Forecast	• Alerted PJM Dispatch of upcoming blizzard conditions and extreme cold via email • Met to discuss holiday forecasts (with extra support from other staff)
Tues.–Fri. Dec. 20–23	Forecast	• Delivered verbal updates on approaching storm risks at the daily Dispatch morning meeting
Wed.–Fri. Dec. 21–23	Forecast	• Provided on-site support, meeting daily with dispatchers to support adjusting the forecast
Thurs. Dec. 22	Dispatch + Forecast	• Collaborated on the load forecast for Dec. 23, increasing the peak forecast to 127,000 MW from the original forecast of 124,600 MW
	Forecast	• Created the preliminary forecast for Dec. 24 with a maximum peak of 124,000 MW
Fri. Dec. 23	Dispatch + Forecast	• Collaborated on load forecast for Dec. 24

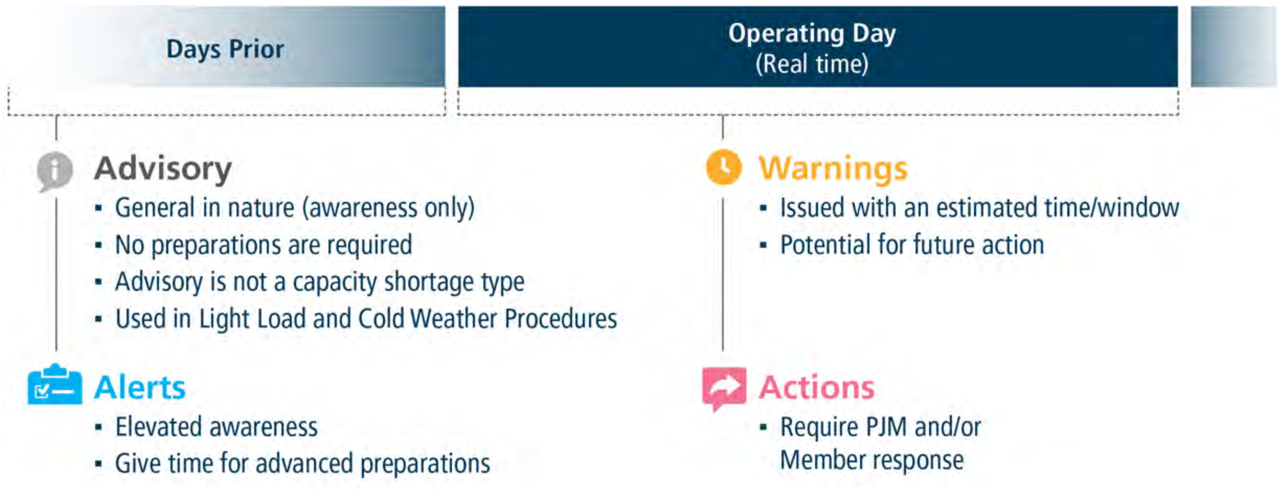
Date	PJM Team	Activity
	Forecast	• At the time of the forecast's creation, the actual load on Dec. 23 was coming in lower than the forecast. When the team began assessing the forecast for Dec. 24, they observed that the actual load was coming in lower than the previous day's forecast. This led the team to determine that holiday impacts were causing the load to come in low and that effect would persist into Dec. 24. • The PJM forecast team created the preliminary load forecast for Dec. 26.
Sat.–Mon. Dec. 24–26	Forecast	• Continued to provide load forecasting guidance and support to Dispatch

Emergency Procedures Issued and Actions Taken in Advance of Operating Day

PJM is responsible for determining and declaring that an emergency is expected to exist, exists or has ceased to exist in any part of the PJM RTO or in any other Control Area that is interconnected directly or indirectly with the PJM RTO. PJM directs the operations of the PJM members, as necessary, to manage, allocate or alleviate an emergency. PJM also is responsible for transferring energy on the PJM members' behalf to resolve an emergency, as well as executing agreements with other Control Areas interconnected with the PJM RTO for the mutual provision of service to meet an emergency.

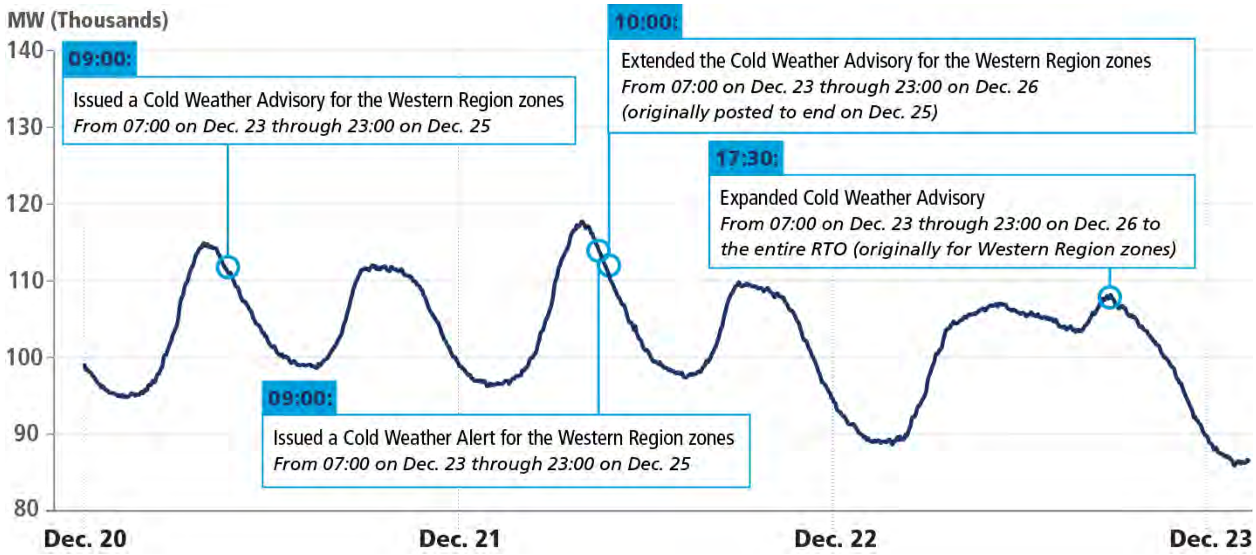
As described in PJM Manual 13, Section 2.3, PJM has established three emergency procedure levels for capacity shortages, as well as an advisory level.

Figure 5. Emergency Procedure Levels



To maximize PJM's ability to operate reliably during periods of extreme and/or prolonged severe weather conditions, procedures are necessary to keep all affected system personnel aware of the forecast and/or actual status of the system and to promote the maximum levels of resource availability are attained. PJM issued both advisories and alerts in the days leading up to Dec. 23 and Dec. 24, as presented in **Figure 6**:

Figure 6. Cold Weather Alerts and Advisories for Dec. 23 and 24



PJM initiated the following steps in advance of the Dec. 23 and Dec. 24 operating days:

- At 09:00 on Dec. 20, PJM issued a Cold Weather Advisory for the Western Region zones from 07:00 on Dec. 23 through 23:00 on Dec. 25. Members are to take any necessary precautions to prepare generating facilities for cold weather operations, including the following actions:
- Erecting temporary windbreaks or shelters, positioning heaters, verifying heat trace systems, or draining equipment prone to freezing
- Updating Markets Gateway by entering unit-specific operating limitations associated with cold weather preparedness (i.e., generator capability and availability, fuel supply and inventory concerns, environmental constraints)
- At 09:00 on Dec. 21, PJM issued a Cold Weather Alert for the Western Region zones from 07:00 on Dec. 23 through 23:00 on Dec. 25. At 10:00 on Dec. 21, PJM also extended the Cold Weather Advisory for the Western Region zones from 07:00 on Dec. 23 through 23:00 on Dec. 26. The purpose of a Cold Weather Alert is to prepare personnel and facilities for expected extreme cold weather conditions. PJM generally issues a Cold Weather Alert when the forecast weather conditions approach minimum or actual temperatures of 10 degrees Fahrenheit or below. PJM can initiate a Cold Weather Alert at higher temperatures if PJM anticipates increased winds or if PJM projects a portion of gas-fired capacity is unable to obtain spot market gas during load pick-up periods. When a Cold Weather Alert is issued, members are to perform the following actions:
- Update their unit parameters, including the Start-up and Notification, Min Run Time, Max Run Time, Eco Min, Eco Max, etc., in Markets Gateway.

- Report to PJM Dispatch any resource limited facilities, as they occur, via Markets Gateway.
- Determine whether alternate fuel will be made available to PJM for dispatch. If made available, any known alternate fuel resource limitations will be communicated via Markets.
- Based on direction received from PJM, call in or schedule personnel in sufficient time to ensure that all combustion turbines and diesel generators that are expected to operate are started and available for loading when needed for the morning pick up.
- At 17:30 on Dec. 22, PJM expanded its Cold Weather Advisory from 07:00 on Dec. 24 through 23:00 on Dec. 26 for the entire RTO. Given the expected weather, PJM was very prudent in developing the operating plans for Dec. 23, as presented throughout this section.

Figure 7 presents the expected member actions for the Advisories and Alerts that were issued in advance of the Dec. 23 and Dec. 24 operating days:

Figure 7. Expected Member Actions for Advisories and Alerts for Dec. 23 and Dec. 24

Dec. 20, 2022

Cold Weather Advisory for Western Region From Dec. 23–26 (Later Expanded to Entire RTO)

- Prepare to take freeze-protection actions, such as erecting temporary windbreaks or shelters, positioning heaters, verifying heat trace systems, or draining equipment prone to freezing.
- Review weather forecasts, determine any forecasted operational changes, and notify PJM of any changes.
- Members are to update PJM with operation limitations associated with cold weather preparedness. Operating limitations include: generator capability and availability, fuel supply and inventory concerns, fuel switching capabilities, environmental constraints, generating unit minimums.

Dec. 21, 2022

Cold Weather Alert Issued for the Western Region for Dec. 23–26 (Later Expanded to Entire RTO)

- Generation dispatchers review fuel supply/delivery schedules in anticipation of greater-than-normal operation of units.
- Generation dispatchers monitor and report projected fuel limitations to PJM dispatcher and update the unit Max Run field in Markets Gateway if less than 24 hours of run time remaining.
- Generation dispatchers contact PJM Dispatch if it is anticipated that spot market gas is unavailable, resulting in unavailability of bid-in generation.

Coordination With Adjacent Systems

In addition to its internal preparations for peak conditions, PJM also coordinates with adjacent systems prior to possible emergency conditions. This coordination can occur through the regional reliability entity responsible for compliance with NERC standards in that region or with the neighboring entity itself.

PJM participates in a daily morning conference call with adjacent systems at 03:30 during which peak load estimates, reserve requirements and estimated loads are discussed. Participants on the call include Tennessee Valley Authority (TVA), Virginia-Carolina (VACAR), Midcontinent Independent System Operator (MISO), PJM and Florida Reliability Coordinating Council (FRCC). There is also a call at 05:00 that PJM conducts with NYISO and a daily call at 08:00 with MISO. Load projections, reserves and anticipated daily challenges are discussed on these calls as well.

During the aforementioned calls, expected conditions were reviewed, and load projections and expected reserve quantities were shared. Members of the Northeast Power Coordinating Council (NPCC), the regional reliability entity for New York ISO (NYISO), ISO New England (ISO-NE), Independent Electricity System Operator (IESO), the Canadian Maritimes, and New Brunswick Power, were anticipating large temperature drops from the incoming arctic air mass and temperatures to be in the single digits. Council members coordinated anticipated operating conditions from multiple transmission facilities that tripped from previous ice storms that had impacted Canadian entities. These transmission facilities limited the entities' ability to export energy to adjacent areas. Members of the NPCC were anticipating tight operating conditions from the reduction of imports and anticipated higher loads from the incoming arctic air mass and agreed to conduct further calls and coordination throughout the duration of the storm.

PJM also met with SERC Reliability Corporation members to review expected conditions and share information to prepare for the event. SERC members were in close coordination throughout the event as well. The FRCC issued conservative operations on Friday, Dec. 23. TVA was managing capacity concerns as they lost units over the midnight period from extreme cold conditions. TVA declared conservative operations on Dec. 23 and EEAs up to an EEA 3 at 05:12 on Dec. 23. Southwest Power Pool (SPP) issued a cold weather advisory along with a resource advisory. On Dec. 23, SPP set a new winter peak of 47, 214 MW. Its previous winter peak was 43,661 MW.

PJM met with MISO to prepare for the event. MISO was monitoring the Arctic air mass forecasted to move into the footprint beginning Dec. 21 and Dec. 22 that was pushing temperatures below normal. MISO was not anticipating any capacity or reliability concerns.

MISO's Outage Coordination Team was evaluating all planned transmission outages, in the event some may need to be delayed due to the cold temperatures. MISO continued to closely monitor the numerous gas pipelines' cold weather notices, and Operational Flow Orders (OFOs) for any potential impact to generation. MISO declared a maximum generation warning for its southern region on Dec. 23 from 09:15 until 13:00 as well as for its entire footprint from 17:30 to 22:00 EST on Dec. 23. PJM had two coordination calls with MISO on each day of the event to exchange information, one at 03:30 and one at 08:00.

The Southern Company Balancing Authority declared an EEA 1 at 01:09 and EEA 2 at 05:33 due to lower-than-optimal generation reserves. The Southern Company Balancing Authority received 1,000 MW of emergency energy from Florida Power & Light and 100 MW of emergency energy from MISO.

As described later in this report, PJM coordinated extensively with TVA throughout the event to coordinate interchange transactions and system conditions. PJM ran studies to simulate additional interchange being exported to its neighbors. PJM will continue to participate in seasonal assessments and preparedness with its neighbors and seek opportunities to enhance coordination with neighbors.

Coordination With Natural Gas Industry

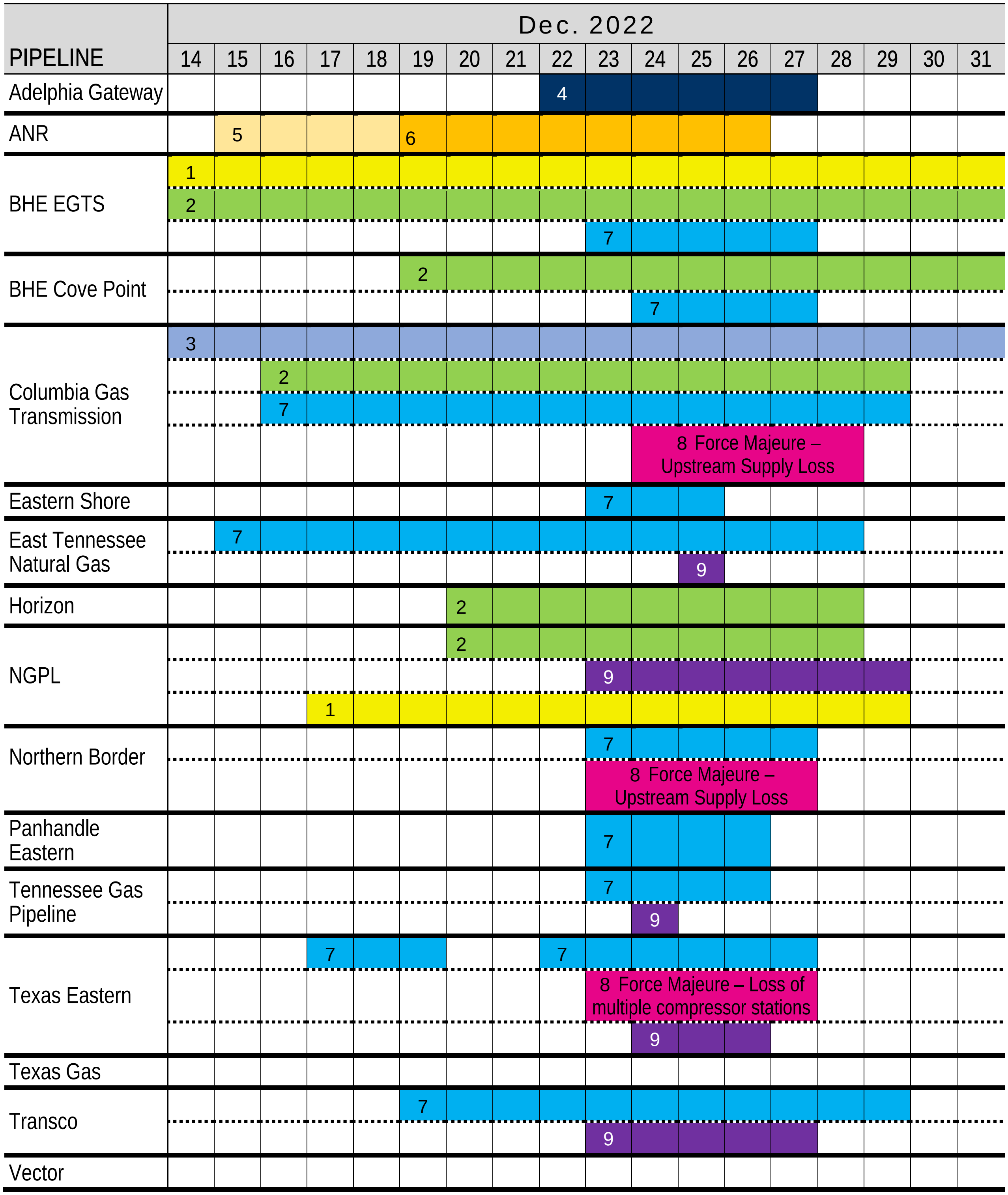
Prior to each winter season, PJM, along with fellow members of the ISO/RTO Council Electric Gas Coordination Task Force, meet with the pipeline industry to review the upcoming winter and discuss mutual preparedness activities.

In addition to daily team meetings to review pipeline conditions and operational impacts, the PJM Gas-Electric Coordination Team conducts weekly operational calls during the winter months (November through March) with all of the major interstate natural gas pipelines within the PJM service territory. These interstate pipelines serve generation resources directly and also serve local gas distribution companies (LDCs), which in turn serve a smaller subset of PJM generators behind the LDC citygates. The purpose of these calls is to assess mutual system conditions. This includes reviewing load forecasts for both the electric and gas systems, any system outages that might impact service to generators, active and pending pipeline capacity restrictions, and any gas generation pipeline nomination anomalies. As a result of FERC's issuance of Order 787, PJM established a Memorandum of Understanding (MOU) with nine of the major pipelines in 2015 and has individual agreements in place with the majority of pipelines and multiple LDCs. During critical gas pipeline capacity-constrained periods, LDCs have the ability to interrupt gas supply to certain gas-fired generators that are served behind the LDC citygates as generators are served at a lower priority level than core residential customers that are considered human needs customers. As such, it is important for PJM to understand when those generators may be interrupted, and for those generators subject to interruption to effectively communicate that information to PJM in a timely manner.

With respect to gas-electric coordination activities leading up to Winter Storm Elliott, these calls with the pipelines began early in the week immediately preceding the impacts of Elliott, and at that point, most of the pipelines had provided notification on their electronic bulletin boards announcing various cold weather alerts and system restrictions. This was in the form of OFOs and Ratable Take Requirements. OFOs are issued to enforce daily balancing rules requiring customer imbalances (difference between nominated gas volume and burned gas volume) to stay within a certain tolerance percentage. Ratable Take Requirements mandate that customers deliver and burn their gas at uniform hourly rates. Pipelines take these actions to mitigate large swings in system pressures. These restrictions gradually increased throughout the week, and by Friday morning, all pipelines had active notices of varying degrees. Operationally, all pipelines appeared to be well prepared for the cold, and even on the morning of Friday, Dec. 23, reports from the pipelines indicated that line pack was high, systems were ready and that load had not yet begun to pick up significantly, particularly in eastern zones.

Figure 8 provides a summary of the pipeline restrictions that were in place from Dec. 14 through Dec. 31.

Figure 8. Interstate/Infrastructure Pipeline Restrictions



	Pipeline Notice
1	Restrictions on Non-Firm Contracts Customers with interruptible transportation contracts at higher risk of not being able to schedule adequate pipeline capacity
2	Ratable Take Requirement Pipeline requiring customers to supply and burn gas at uniform hourly rates to avoid excessive pressure fluctuations
3	Critical Day (Transport Deliveries/Storage Withdrawals) Pipeline requiring customers to stay within their transportation and storage contractual requirements
4	Action Alert (Daily Balancing) Requires customers to ensure that their supply and demand is balanced at the end of each 24-hour gas day within the tolerances provided by the pipeline Tariff provisions
5	Phase 1 Cold Weather Advisory Alerting customers of pending cold temperatures and tightening system conditions
6	Phase 2 Cold Weather Extreme Conditions Requires customers to abide by their specific contract and rate provisions and to burn gas on a uniform hourly basis as their contracts direct; interruptible contracts at greater risk of having service cut
7	Daily Balancing OFO Requires customers to ensure that their supply and demand is balanced at the end of each 24-hour gas day within the tolerances provided by the pipeline Tariff provisions
8	Force Majeure Declared when there an event outside of the pipeline's control occurs that may render service unavailable to certain customers regardless of contractual arrangements (e.g., loss of compressor station)
9	Loss of Upstream Supply As a result of less gas coming into the pipeline due to upstream supply failures, pipelines provide notice that risk of downstream pressure loss and customer nomination cuts are increasing.

On the gas commodity supply side, nearly all of the natural gas consumed by generation in PJM originates in the Marcellus and Utica shale in the Appalachian region. Historically, loss of supply due to gas production well freeze-offs during cold snaps has not been as severe as compared to gas basins in the south central and southwestern United States. This was confirmed during outreach with a sample of producers after Winter Storm Uri in February 2021. While Uri did not have a major direct impact on PJM, there was a desire to get out ahead of the issues to determine if the supply losses experienced during Uri could occur in the Appalachian region. The feedback from those producers indicated that gas production and midstream processing and transport were much more hardened against cold temperatures compared to the same facilities in the south and southwest. Typical losses due to well freeze-off conditions range from around 2 to 3 Bcf (billion cubic feet) per day in the Appalachian region and this was the general assumption going into Elliott. In the end, the actual supply loss was closer to 10 Bcf, which significantly challenged the ability for natural gas-fired resources to procure fuel, likely leading to a portion of the outages on these resources.

It is important to note that while PJM coordinates with the natural gas industry prior to and during events such as Winter Storm Elliott, the tools used by PJM system operators to commit and dispatch resources relies on the availability and offer data submitted for each generator. If the generator availability and offer data is not consistent with the resource's true capability, PJM operators are left with an inaccurate view of the true capability of the fleet.

Day-Ahead Market and Reliability Assessment Commitment Results

The PJM Energy Market consists of two markets: a Day-Ahead Market and a Real-Time Market. Two days prior to an operating day, PJM begins to set up the conditions, such as the expected outages and conditions for the operating day, in the model for the Day-Ahead Energy Market. (The two-settlement market mechanism is described in more detail in Appendix A.)

The Day-Ahead Market is cleared so that the cost to serve demand (physical and virtual) is minimized, while respecting the physical operating limits of the transmission system. Commitments in the Day-Ahead Market are financially binding on participants. Any differences between day-ahead commitments and what occurs in the operating day is addressed in the Real-Time Market. The PJM Day-Ahead Market utilizes the bid-in load from the Load Serving Entities, as well as virtual bids from Market Participants.

Capacity resources are required to offer into the Day-Ahead and Real-Time markets with accurate reporting of their availability and unit parameters, which include but are not limited to, start time, ramp rate, and minimum output and maximum output. In addition, resources can and do update their offers in both of these markets to reflect their actual fuel and operating costs.

For each operating day, PJM performs reliability analysis and develops an operating plan. PJM performs two reliability analyses a day ahead of the operating day. The first analysis, performed by the PJM reliability engineers, is an input into the PJM Day-Ahead Market performed prior to closing at 11:00. The second reliability analysis, called Reliability Assessment Commitment (RAC), is performed after the Day-Ahead Market clears and includes the commitments made in the Day-Ahead Market. After 16:15, PJM begins the RAC run, which commits adequate generation to meet the PJM forecasted demand plus reserves, while minimizing start-up and no-load cost. The focus of this commitment is reliability, and the objective is to minimize start-up and no-load costs for any additional resources that are committed. Using the most up-to-date weather forecast, load forecast, transmission facility and generator availability, and other information, PJM commits additional generation, if necessary, to satisfy both expected loads and the needed reserves for the operating day. This includes scheduling additional resources during the operating day that did not have a Day-Ahead Market commitment. PJM scheduled 4,411 MW of combustion turbines (CTs) between Dec. 23 and Dec. 24.

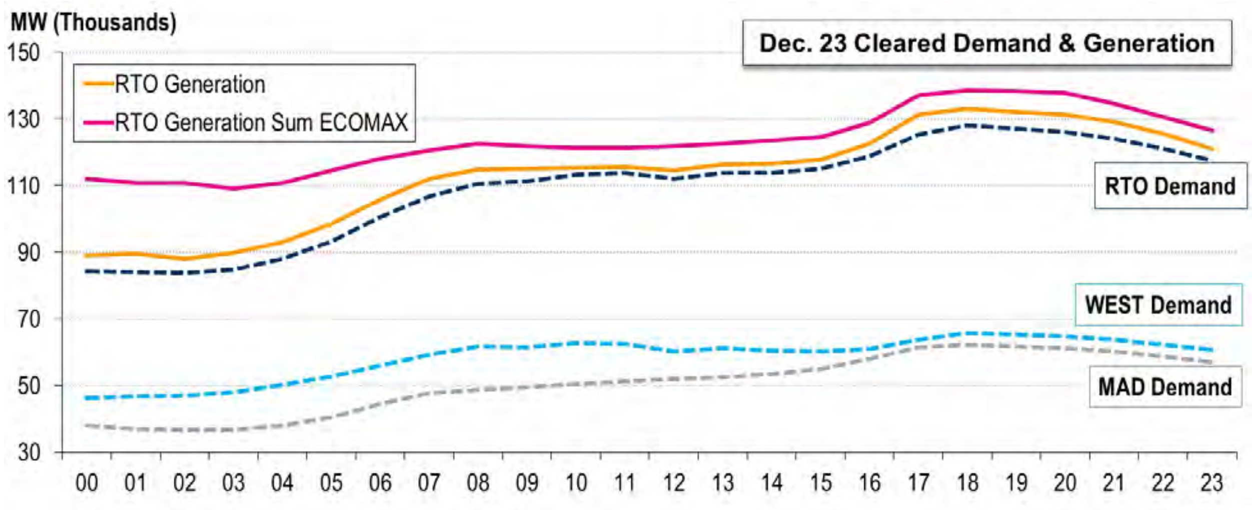
PJM also performs additional reliability analysis to confirm transmission facilities are operated within their equipment limits when committing generation. During severe winter weather events, PJM communicates extensively with both Generation Owners and gas pipeline operators to adequately understand the likelihood that natural gas-fueled generators are able to procure the gas needed to operate. PJM may perform additional resource commitment runs, as necessary, based on updated PJM load forecasts and updated resource availability information. It is important to note that these resource commitment runs use available offer data submitted into Markets Gateway by Generation Owner/operators. If the offer information is not accurate, the commitment results and operating plan PJM develops may be inadequate. Following these commitment runs, PJM sends out individual generation commitment updates to specific Generation Owners only.

The outcome of all of these processes is a set of resource commitments expected to be able to maintain reliability during the operating day.

Dec. 23

PJM's Dec. 23 operating day plan was prudent, given the expected. PJM scheduled the system such that almost 29,000 MW of reserve capacity was available to meet load and generation contingencies, and to support neighboring systems, according to the information submitted by Market Participants. Figure 9 presents the cleared day-ahead demand, and the generation committed to meet that demand, plus reserves for Dec. 23 operating day.

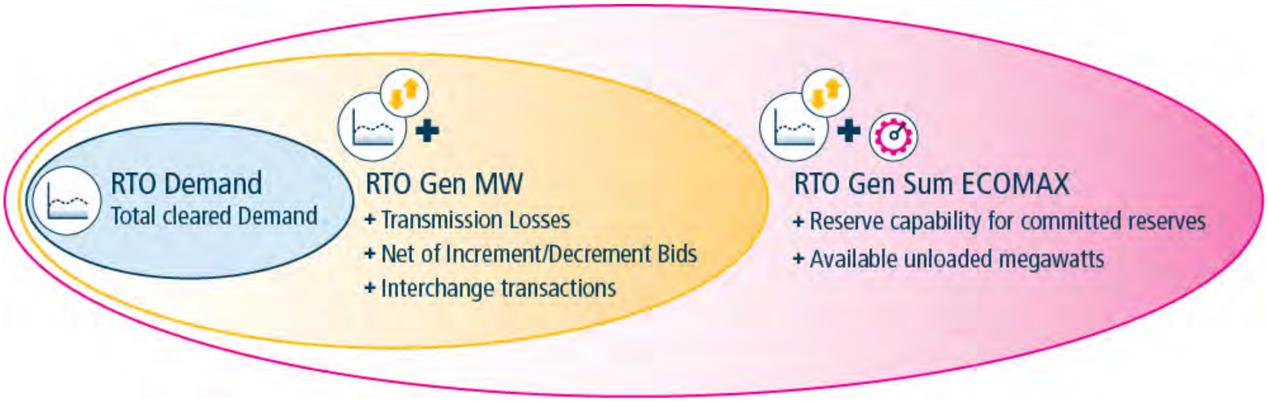
Figure 9. Dec. 23 Cleared Demand and Generation from Day-Ahead Market



In Figure 9:

- RTO Demand is the total cleared demand in the Day-Ahead Market, which includes fixed demand and cleared price-sensitive demand. The RTO Demand is not the same as the PJM Load Forecast.
- RTO Gen MW is the total generation megawatts loaded (or cleared) in the Day-Ahead Market. It includes all cleared generation. This value is greater than the RTO Demand because it accounts for transmission losses, the net of increment and decrement bids, and interchange transactions in or out of the PJM Balancing Authority.
- RTO Gen Sum ECOMAX is the total sum of all online generation resource's economic maximums committed in the Day-Ahead Market. This value is larger than the RTO Gen MW because it includes reserve capability for committed reserves and unloaded megawatts not explicitly needed in the clearing process but are available due to the mix of resources committed in the Day-Ahead Market.

Figure 10. Cleared Demand & Generation Representation



For the Dec. 23 operating day, the Day-Ahead Market committed 133,165 MW of generation for energy (yellow line in Figure 9), with 5,474 MW of unloaded generation (magenta line in Figure 9), including approximately 11,000 MW of combustion turbines (CTs) scheduled economically and 1,270 MW committed for reliability purposes to control constraints. PJM also scheduled an additional 3,168 MW in the RAC runs. In addition, there was another approximately 16,000 MW in CTs available for dispatch in real time that were not committed in the Day-Ahead Market.

Entering the operating day on Dec. 23, PJM had approximately 158,000 MW of operating capacity with a projected peak load of around 127,000 MW. Based on the Day-Ahead Market results, PJM did not anticipate the need to run a significant amount of additional CTs on Dec. 23 or Dec. 24. However, as more and more generating resources started to report their unavailability to PJM during the evening peak on Dec. 23 and through the early morning hours of Dec. 24, PJM Dispatch began scheduling additional CTs to come online.

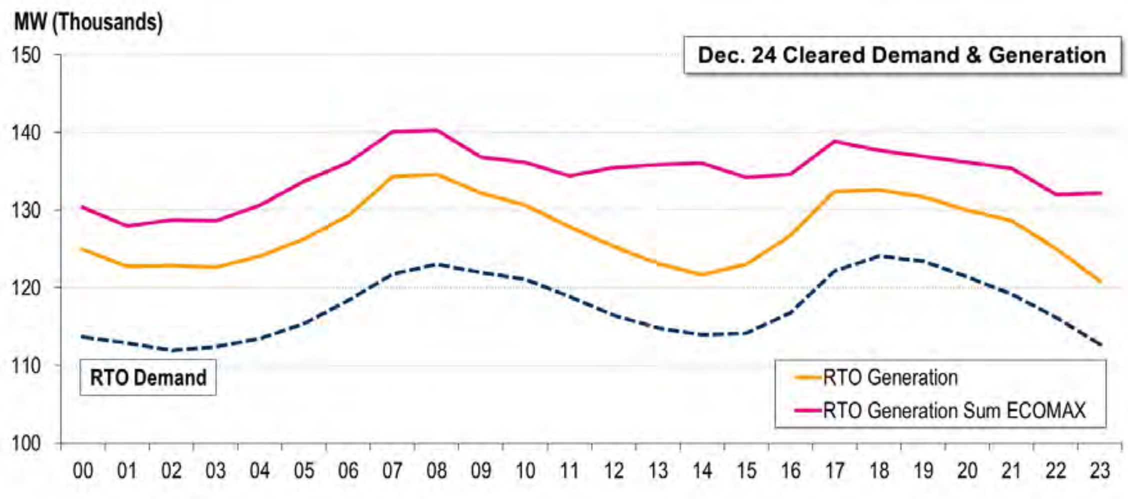
As early as Dec. 20, generation resource operating limitations and minimum operating, design or performance temperature were submitted to PJM in advance of the cold weather event after PJM declared a Cold Weather Advisory. All of the generator-submitted data was taken into consideration, with PJM forecasting a significant surplus of generation leading into the Dec. 23 operating day. This included accounting for a historical average of generator forced outages through cold weather events. As such, PJM did not declare a Unit Startup Notification Alert or commit any long lead generation or recall maintenance outages to meet capacity forecasts. As described in the Operating Day section of this report, in 92% of cases where generators failed to perform, PJM either had little or no notice, and very few resources provided updated parameters to reflect fuel supply constraints or other unit issues.

Dec. 24

Prior to the operating day of Dec. 24, PJM issued a Cold Weather Advisory on Dec. 20 for the period of Dec. 23 to 26. PJM then issued a Cold Weather Alert for the entire RTO on Dec. 23, effective for Dec. 24. The operating plan for Dec. 24 was updated based on operating conditions experienced on Dec. 23. Load forecasts were updated, and unit commitments' needs were updated based on generating resources that experienced forced outages throughout the day on Dec. 23.

Figure 11 presents the cleared day-ahead demand and committed generation to meet that demand, plus reserves for the Dec. 24 operating day.

Figure 11. Dec. 24 Cleared Demand & Generation from Day-Ahead Market



For Dec. 24, the Day-Ahead Market committed 134,615 MW of generation for energy (yellow line in Figure 11), with an additional 5,672 MW of unloaded generation (magenta line in Figure 11). PJM committed resources based on the RAC runs and for reliability. PJM also committed additional resources, based on unit availability and other parameters in Markets Gateway. In total, approximately 6,000 MW of additional capacity for Dec. 24 was committed, beyond what was committed in the Day-Ahead Market, to support the anticipated loads and reserve requirements. In addition, there were another 9,500 MW in CTs available for dispatch in real time, as communicated by generators to PJM. This results in a total of approximately 155,700 MW in operating capacity for Dec. 24.

PJM system operators knew that there was going to be uncertainty in the load forecast as a result of the extreme weather. In addition to accounting for weather and load uncertainty, PJM scheduled additional reserve resources in anticipation of generator failures. Generation failures often increase somewhat during bitter-cold conditions – recent history indicates on the order of 5% to 10%. On Dec. 24, several generating resources were committed in the Day-Ahead Market but were not available in the operating day due to forced outages. The decision was therefore made to operate prudently by scheduling additional reserves. Generation performance, including generation resources that were committed in the Day-Ahead Market but were not available in the operating day, is presented in the Operating Day section of the report.

Utilizing these commitments, as well as the generator parameters of units that did not have Day-Ahead Market commitments, but were reporting to PJM as available with short notice, PJM anticipated that approximately 155,700 MW of generation would be available for Dec. 24.

Operating Day

The Operating Day section of the report details the events and actions PJM initiated during the operating days of Dec. 23 and Dec. 24 to maintain reliability and not shed load. It describes the emergency procedures issued and actions taken, the public Call for Conservation, the Disturbance Control Standard event, as well as the generation and Demand Response performance, real-time interchange, and gas availability issues.

On Dec. 23 and Dec. 24, PJM remained reliable, was able to serve its customers, and was able to support neighboring areas to the south and minimize the amount of load shed in these external areas. PJM reliably met the demand on both

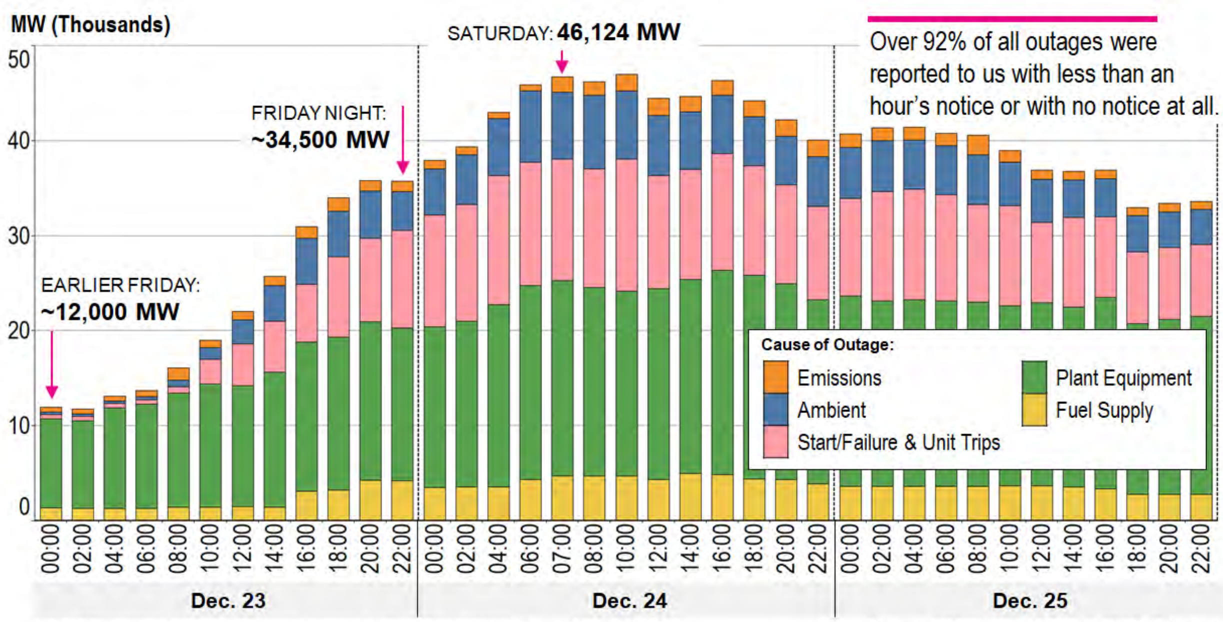
Dec. 23 and Dec. 24 by employing several emergency procedures and utilizing market signals to incent response from the supply and demand side resources. Although the 136,010[3] MW peak load on the evening of Dec. 23 was not one of PJM's top 10 peak winter load days, it essentially matched the forecasted 50/50 peak load for the 2022/2023 winter season (approximately 25,000 MW above an average winter day).

As described in the Advanced Planning section, going into the Dec. 23 operating day, PJM had over 158,000 MW of operating capacity with a projected peak load of around 127,000 MW, resulting in over 30,000 MW of reserves. Based on the Day-Ahead Market results, PJM did not anticipate the need to run a significant amount of additional generation on Dec. 23 or Dec. 24. However, as more and more generating resources started to report their unavailability to PJM during the evening peak on Dec. 23 and through the early morning hours of Dec. 24, PJM Dispatch began scheduling additional generators to come online.

Emergency Procedures Issued and Actions Taken During Dec. 23 and Dec. 24

As the extreme cold front moved into the PJM region throughout Dec. 23, the load shape looked more like a summer day, with a lower morning valley that ramped up throughout the day. Coincident with the increasing demand, PJM began experiencing rapidly increasing levels of forced generation outages, as shown in Figure 12. Additional information on generation performance is presented in later in this section.

Figure 12. Forced Outages by Cause



Note: Only even hours are shown for readability with the exception of Dec. 24, 2022, 07:00, which was the hour with the largest amount of forced outages and derates.

Source: GADS as of March 1, 2023. Wind and solar unit outages are not included in the data.

The conditions of Winter Storm Elliott led to PJM requesting the loading of Synchronized Reserve generation on five separate occasions during Dec. 23 and Dec. 24. Four of these events were called in response to a low Area Control Error (ACE) caused by increasing load and generation tripping and start failures. One of the events was called in direct response to the loss a generating unit. Five Synchronized Reserve Events over a two-day period is extremely unusual. All five of the events on Dec. 23 and Dec. 24 exceeded 10 minutes in duration, which is again extraordinary. Since the start of 2021, there have been 47 Synchronized Reserve Events, of which only 17 (36%) were more than 10 minutes in

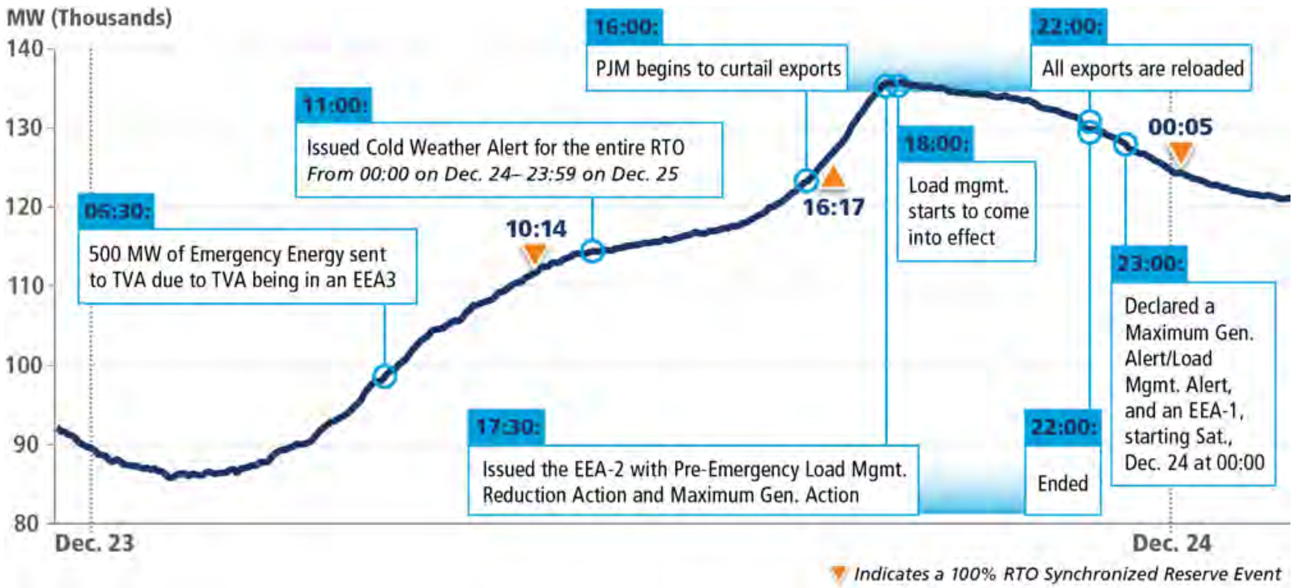
[3] The Dec. 23 peak of 136,010 MW incorporates Demand Response as part of the total.

duration, and five of these 17 occurred during Winter Storm Elliott. Additional information on Synchronized Reserve Events and Reserve performance is presented in the Markets Outcomes section of this report.

Dec. 23

PJM system operators initiated several actions on Dec. 23 as load continued to increase. **Figure 13** presents the PJM emergency procedures initiated, as well as the PJM load and the Synchronized Reserve Events, for Dec. 23.

Figure 13. Dec. 23 Emergency Procedures



Early in the morning on Dec. 23, PJM was exporting energy to adjacent areas and tracking under the load forecast. At 06:30, PJM provided 500 MW of emergency energy to TVA, who had issued a NERC Energy Emergency Alert Level 3 (EEA3), which is issued when the Balancing Authority, in this case TVA, is unable to meet the minimum contingency reserves requirements. At 10:00 on Dec. 23, PJM conducted an SOS-Transmission call to inform Transmission Owners of anticipated system conditions and the operating plan for the day.

	Dec. 23 HE 05
Outages	13,449 MW
Interchange	7,517 MW
Load	88,237 MW

At 10:14 on Dec. 23, PJM deployed Synchronized Reserves to recover low ACE caused by increasing load combined with generation resources tripping offline and failing to start. At this time, total PJM reserves were approximately 1,500 MW. At 11:00 on Dec. 23, PJM issued a Cold Weather Alert for the entire RTO from 00:00 on Dec. 24 through 23:59 on Dec. 26.

Beginning around 14:00 on Dec. 23, generation continued to trip or fail to start at a rate of approximately 1,800 MW per hour. This posed a challenge for PJM's ability to deliver exports to neighbors. During this period, the operational situation was strained for a number of reasons:

	Dec. 23 HE 13
Outages	24,032 MW
Interchange	8,283 MW
Load	115,048 MW

- PJM's ACE was dropping and trending significantly below zero, indicating insufficient generation to support load due to generator outages and failures. PJM found that it was unexpectedly and rapidly exhausting its operating and Primary Reserves because of the unexpected generator outages.
- PJM had put generation resources on notice, through Advisories and Alerts, of PJM's need for them to be prepared to run. PJM relied on Generator Owner/operator-submitted data and believed these reserves were available. In

many cases, this data did not reflect the actual capability of the generator and PJM would only learn of the generation resource failures at the time PJM was expecting these resources to begin to run.

- A Disturbance Control Standard (DCS) event, discussed later in this report, was also unfolding during this same time period.

Late in the afternoon of Dec. 23, temperatures continued to drop rapidly, and load continued to increase very quickly. During this period of operational uncertainty and deteriorating system conditions, PJM took additional emergency steps it determined were necessary to preserve the reliability of the system. Despite margins being incredibly tight, no load was shed.

Shortly after 16:00, PJM began cutting non-firm exports, consistent with PJM Manual 13. Export transactions had been decreasing throughout the afternoon, but by 16:00, it was evident PJM could no longer support non-firm exports. Given the trends in ACE, the high outage rates being observed in real time, and the time it would take for the impacts of the capacity recalls to be known, PJM Dispatch believed capacity recalls alone were insufficient to stabilize the system.

	Dec. 23 HE 15
Outages	26,672 MW
Interchange	6,732 MW
Load	117,143 MW

While the export transactions were being curtailed, at 16:17, PJM entered into another Synchronized Reserve Event due to low ACE caused by increasing load and generation resources tripping and failing to start. PJM deployed Synchronized Reserves for almost two hours, before canceling at 18:09. Load was continuing to increase, and PJM had several additional generation resource trips throughout the Synchronized Reserve Event period. The PJM ACE did not recover until after Demand Response was implemented at 18:00.

Available Synchronized Reserves continued to drop as PJM began calling upon these resources for energy, with many failing to perform at expected levels. At times during this period, PJM was within 1,000 MW of its required Synchronized Reserve level of 1,667 MW. PJM dipped below this required Synchronized Reserve threshold for a portion of the hour ending 18:00 because it was deploying Synchronized Reserves but not getting the expected response.

At 17:30, ACE was very low at nearly -3,000 MW, and the load was continuing to grow. In response, PJM issued a NERC Energy Emergency Alert Level 2 (EEA-2[4]) with Pre-Emergency Load Management Reduction Action and Maximum Generation Action, directing generation resources to operate above their normal maximum output levels. An EEA-2 is issued to ensure all NERC Reliability Authorities understand the potential and actual PJM system emergencies and is typically issued when the following events have occurred: public appeals to reduce demand; voltage reduction; and interruption of non-firm load in accordance with applicable contracts, demand-side management, or utility load conservation measures (NERC Standard EOP-11).

	Dec. 23 HE 16
Outages	28,351 MW
Interchange	6,032 MW
Load	119,375 MW

Certain emergency warnings and actions trigger a Capacity Performance Assessment Interval (PAI). The issuance of the EEA-2 with Pre-Emergency Load Management Reduction Action and Maximum Generation Action triggered the first performance assessment event, requiring PJM to evaluate the performance of all resources located in the Emergency

[4] EOP-011 NERC Energy Emergency Alerts (EEAs):
EEA0 – No Energy Deficiencies
EEA1 – All Available Resources in Use or Anticipated to be In Use; triggered when PJM issues Maximum Generation Emergency Alert)
EEA2 – Load Management Procedures in effect; triggered when PJM issues Emergency Mandatory Load Management Reduction, Voltage Reduction Action, or Deploy All Resources Action (whichever is issued first)
EEA3 – Firm Load Interruption Imminent or in Progress; triggered when PJM issues Manual Load Dump Action

Action area for each applicable five-minute interval. The performance assessment events are described in more detail in the Markets Outcomes section of the report.

PJM also called for 30-minute and 60-minute Emergency Demand Response to be activated. The 30-minute Emergency Demand Response came into effect by 18:00, and the 60-minute Demand Response came into effect by 18:30. PJM did not call for the two-hour Demand Response resources, as these resources would not have been implemented until after the evening peak. Demand Response performance can be difficult to determine in real time due to the lack of visibility of the performance to the system operator. More information on the performance of Demand Response is described later in this section.

	Dec. 23 HE 18
Outages	33,040 MW
Interchange	1,527 MW
Load	130,856 MW

Generation resources continued to trip offline and fail to start, resulting in ACE trending low during the hour ending 18:00. Starting at 17:05, PJM called Northeast Power Coordinating Council (NPCC) for 1,500 MW of shared reserves. NPCC is made up of New York and the six New England states, as well as the Canadian provinces of Ontario, Québec and the Maritime provinces of New Brunswick and Nova Scotia. Shared Reserve Activation is a procedure between the NPCC and the PJM Mid-Atlantic Control Zone to jointly activate a portion of their 10-minute reserve following any of the following situations:

- Generation or energy purchase contingencies equal to or greater than 500 MW (300 MW for the Maritimes) occur under conditions where activation assists in reducing a sustained load/generation mismatch.
- Two or more resource losses below 500 MW (300 MW for the Maritimes) within one hour of each other
- Periods of significant mismatch of load and generation

The objective of Shared Reserve Activation is to provide faster relief of the initial stress on the interconnected transmission system.

Over the evening peak on Dec. 23, PJM attempted to commit additional generating units that reported to PJM as being available to schedule. PJM system operators also considered long-lead-time resources that were beyond the window to be requested to start, which totaled about 3,000 MW. Generator maintenance outages that were recallable totaled about 1,692 MW; however, these are only recallable with 72-hours' notice. (Note: if PJM determines that it must rescind its approval of a Generator Maintenance Outage of a Generation Capacity Resource that is already underway in order to preserve the reliable operation of the PJM region, PJM must provide the member at least 72-hours' advance notice.)

Following the peak at approximately 18:10, PJM began lifting export transaction curtailments. By 22:00, PJM exports had returned to full flow. (Additional information on the real-time interchange is presented later in this section.)

	Dec. 23 HE 22
Outages	36,054 MW
Interchange	3,274 MW
Load	133,096 MW

At 23:00, load began to slowly ramp down, leading PJM to cancel the EEA-2 and the Pre-Emergency Load Management Reduction action at 23:00, ending the first performance assessment event. In addition, at 23:00 on Dec. 23, PJM declared a Maximum Generation Alert/Load Management Alert for Dec. 24, which provides an early alert that system conditions may require the use of the PJM emergency procedures. This is implemented when Maximum Emergency generation is called into the operating capacity or if Demand Response is projected to be implemented. When PJM declares a Maximum Generation Alert/Load Management Alert:

- Member transmission and generation dispatchers are expected to review plans to determine if any maintenance or testing, scheduled or being performed, on any monitoring, control, transmission, or generating equipment can be deferred or canceled. Transmission and generation dispatchers are expected to suspend any high-risk testing of generating or transmission equipment.

- Member generation dispatchers are expected to report to PJM Dispatch any and all resource-limited facilities as they occur via Markets Gateway and update PJM Dispatch. Member generation dispatchers are also expected to update the "early return time" for any planned generator outages as indicated in PJM Manual 10, Section 2.

PJM also issued a NERC Energy Emergency Alert Level 1 (EEA-1) starting Saturday, Dec. 24, at 00:00, indicating PJM foresees or is experiencing conditions where all available resources are scheduled to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required contingency reserves.

Shortly before midnight on Dec. 23, PJM issued a Call for Conservation for the entire PJM footprint, asking consumers to scale back their energy use, where possible, between the hours of 04:00 on Dec. 24 and 10:00 on Dec. 25.

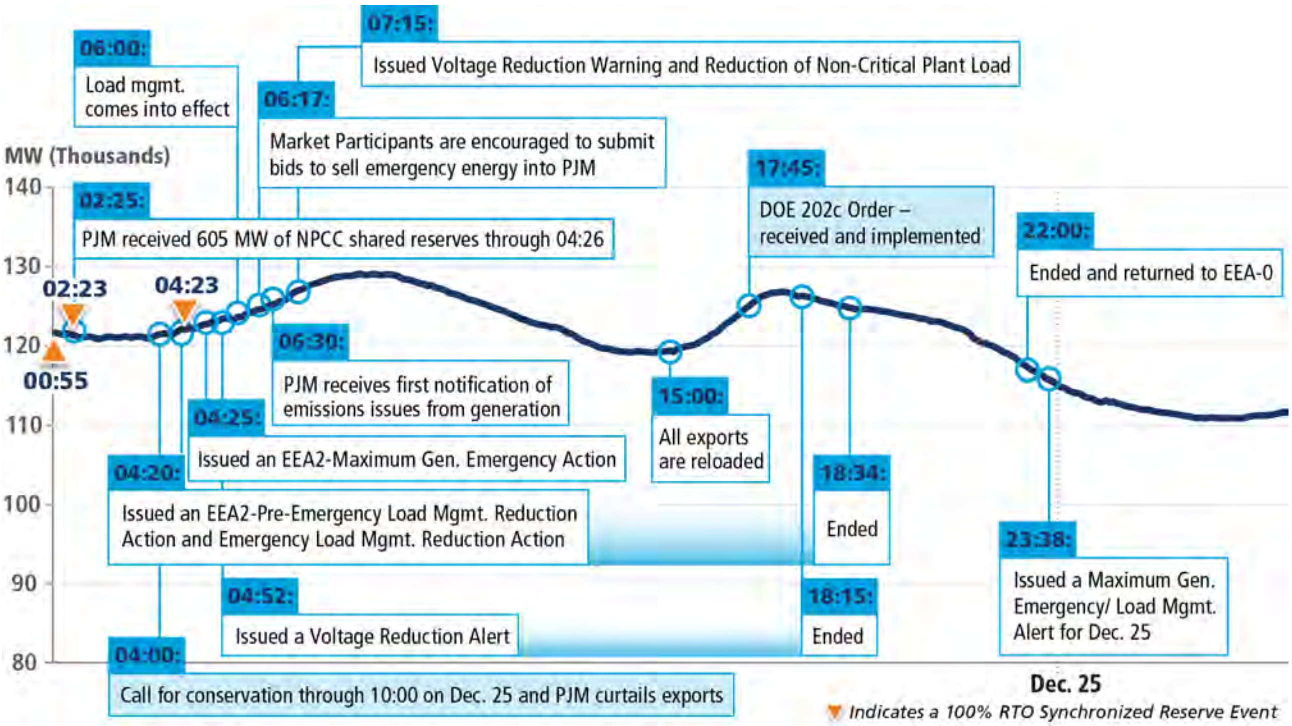
Dec. 24

The high demand for electricity continued after the peak on Dec. 23 and into the overnight period of Dec. 24. In addition to forced outages, approximately 6,000 MW of generators were called but were not online for their expected start time for the Dec. 24 morning peak, with the vast majority of these being gas-fired resources.

The high rates of generator outages also limited PJM's ability to replenish pond levels for pumped storage hydro prior to the morning peak on Dec. 24, leaving PJM with extremely limited run hours for pumped storage generation. Between forced outages, derates, generators not starting on time, and the inability to fill pumped storage hydro ponds, approximately 47,000 MW of the generation fleet in the PJM region was unavailable for the Dec. 24 morning peak. Additionally, the valley load during the early morning hours on Dec. 24 was atypically high. It was approximately 40,000 MW higher than the next-highest valley over the last decade.

PJM system operators took the several actions on Dec. 24 to maintain system reliability and serve load. Figure 14 presents the PJM emergency procedures issued, as well as the PJM load, for Dec. 24.

Figure 14. Dec. 24 Emergency Procedures



At 00:05 on Dec. 24, PJM deployed Synchronized Reserves due to low ACE caused by increasing load and generator trip and start failures. At 02:23, PJM deployed Synchronized Reserves again for approximately one hour to recover from another generation resource trip. At 02:25, PJM received 605 MW of NPCC shared reserves from 02:25 through 04:26. More information on the Synchronized Reserve Events is presented in the Markets Outcomes section of this report.

	Dec. 24 HE 01
Outages	38,368 MW
Interchange	4,604 MW
Load	124,757 MW

During a typical midnight period, load reduces, and PJM would operate pumped storage resources as pumps to fill their ponds so that they have the ability to generate for the upcoming peak. Operating a pumped storage resource in pumping mode increasing load on the system because electricity is consumed to operate the resource as a pump. Given the tight conditions, PJM was not able to pump at any of the pumped storage facilities prior to the morning peak. This left PJM with extremely limited run hours for pumped storage generation. As previously stated, going into the morning peak on Dec. 24, resource unavailability was approximately 47,000 MW, including the unavailability of pumped storage hydro generation.

At 04:20 on Dec. 24, PJM issued an EEA-2 – Pre-Emergency Load Management Reduction Action and Emergency Load Management Reduction Action. In this case, PJM dispatched all Load Management, starting with long lead (120 minute) at 04:20, short lead (60 minute) at 05:00, and quick lead (30 minute) at 05:30. Demand Response performance is described later in this section.

At 04:23, PJM deployed Synchronized Reserves again due to low ACE caused by increasing load and generation resources tripping and start failures. And then at 04:25, PJM issued an EEA-2 – Maximum Generation Emergency Action and began to load Maximum Emergency generation. This triggered the Dec. 24 PAI event. When PJM issues a Maximum Generation Emergency Action:

	Dec. 24 HE 03
Outages	40,243 MW
Interchange	3,322 MW
Load	121,487MW

- Member generation dispatchers are expected to report to PJM all resource-limited facilities as they occur in Markets Gateway and update PJM Dispatch. Generation dispatchers also suspend regulation and load all units to the Maximum Emergency generation level and then notify PJM Dispatch of any Maximum Emergency generation load prior to PJM requested Maximum Emergency generation is loaded.
- Non-Retail Behind-the-Meter Generation (NRBMG) is also loaded. NRBMG performance is described later in this section.

At 04:52, PJM issued a Voltage Reduction Alert. A Voltage Reduction Alert notifies members that a voltage reduction may be required during a future critical period. This alert is issued when the estimated Operating Reserve capacity is less than the forecasted Synchronized Reserve requirement. When PJM issues a Voltage Reduction Alert:

- Member generation dispatchers are expected to order all generating stations to curtail non-critical station light and power.
- Member transmission dispatchers and distribution providers (DPs) are expected to prepare to reduce voltage, if requested.
- Member transmission dispatchers/DPs and curtailment service providers (CSPs) are expected to notify appropriate personnel that there is a potential need to implement load management programs, in addition to interrupting their interruptible/curtailable customers in the manner prescribed by each policy, if it has not already been implemented previously.
- Market Participants are expected to remain on heightened awareness regarding PJM system conditions and the potential need for Emergency Energy Purchases.

At 06:17, PJM requested bids for emergency energy and PJM also repeated a public appeal to conserve energy. Note: PJM did not load emergency imports on Dec. 24.

At 07:15, PJM issued a Voltage Reduction Warning and Reduction of Non-Critical Plant Load, warning members that the available Synchronized Reserve is less than the Synchronized Reserve Requirement and that present operations have deteriorated such that a voltage reduction may be required.

	Dec. 24 HE 06
Outages	46,036 MW
Interchange	1,437 MW
Load	122,172 MW

At 07:30, PJM conducted an SOS-Transmission conference call with the PJM Transmission Owners to update their leadership on the situation and indicated PJM was in a very critical operating period, with the potential that PJM may need to shed load. Another SOS-Transmission conference call took place at 10:00.

As PJM approached the morning peak, PJM was a net importer of energy. TVA and Duke were both in an EEA-3 and shedding load. PJM was unable to provide assistance to TVA and Duke, and PJM was receiving assistance primarily from NYISO.

Forced outages of generation continued to increase through the morning peak on Dec. 24, with an estimated level of 41,000 MW of outages and 200 unit trips. Factoring in a number of reserve generators (units that are offline and available – that are called if needed) that missed scheduled start times Saturday morning or operated at less than capacity, combined with PJM's inability to replenish pumped storage based on the lack of availability of generators overnight, PJM was missing approximately 47,000 MW of the generation fleet by the morning peak of Dec. 24, the coldest day of the holiday weekend.

The morning peak for Dec. 24 was approximately 130,000 MW, occurring at 08:30.

As the morning peak was occurring, it was reported to PJM that several generators may need to come offline at or around the evening peak due to emissions restrictions. At this point, PJM contacted the U.S. Department of Energy (DOE) and held several calls to discuss the concerns and options available to ensure the units could remain online if needed. PJM also began outreach to state utility commissions and environmental agencies in states where there was a potential to operate units under a DOE Emergency Order.

Heading into Saturday evening, there was still uncertainty about resource performance. To mitigate the risk of generators coming offline due to emissions limitations, PJM submitted a petition to the DOE Saturday afternoon. At 17:30, the DOE issued an emergency order under Section 202(c) of the Federal Power Act, determining that an electric reliability emergency existed within the PJM region that required intervention by the United States Secretary of Energy to keep the power flowing.

The emergency order was effective Dec. 24 through 12:00 on Dec. 26. The order authorized all electric generating units serving the PJM footprint to operate up to their maximum generation output levels under limited, prescribed circumstances, even if doing so exceeded their air quality or other permit limitations.

Two generating units that fell under the order ran at levels that exceeded a condition in their operating permit. The Department of Energy requires PJM to identify those generators, which were Bethlehem Energy in Bethlehem, Northampton County, Pennsylvania, and York Energy 1 in Peach Bottom Township, York County, Pennsylvania. On Dec. 24, PJM communicated the need to operate these units under the DOE emergency order to the Pennsylvania Department of Environmental Protection. In accordance with the DOE's requests, PJM followed up with communications to the local communities where the plants are located through local media outlets.

The evening peak for Dec. 24 was approximately 136,000 MW. Following the evening peak, PJM started to cancel emergency procedures. At 18:15, PJM canceled the Voltage Reduction Warning and the Reduction of Non-Critical Plant Load. At 18:34, PJM canceled the Voltage Reduction Alert.

	Dec. 24 HE 17
Outages	47,310 MW
Interchange	3,607 MW
Load	120,183 MW

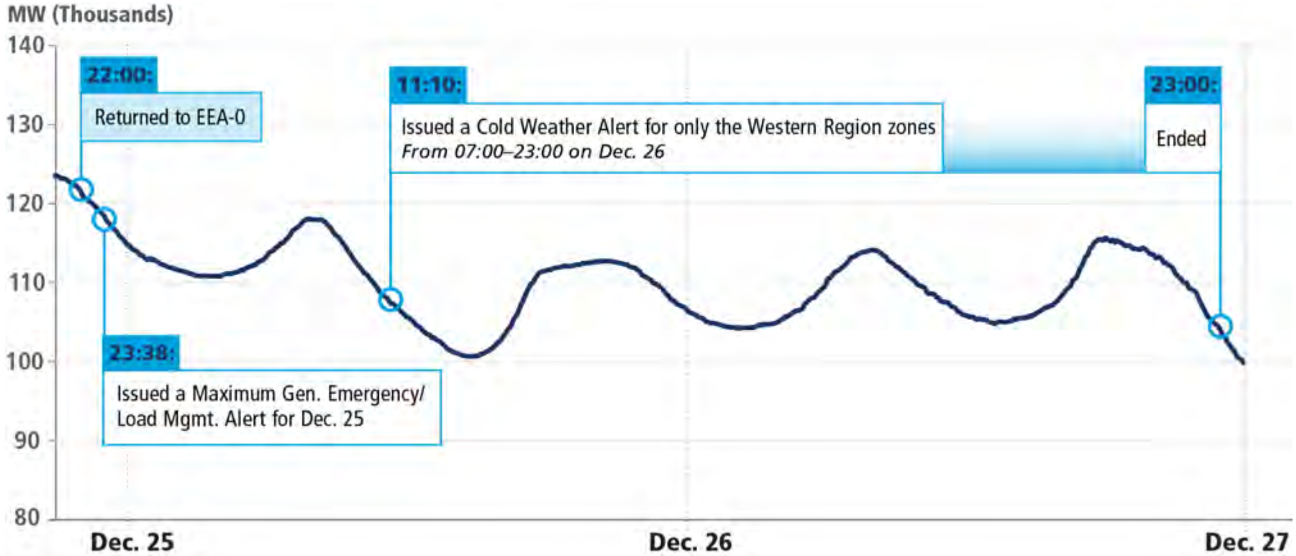
At 22:00 on Dec. 24, PJM canceled the Max Emergency Generation Action. This ended the Dec. 24 PAI. Around 22:00, the Demand Response ended, and PJM backed out of the EEA-2, indicating PJM was able to meet its load and Operating Reserve requirements. PJM's Call for Conservation also ended at this time.

At 22:38 on Dec. 24, PJM issued a Max Emergency Generation Alert for Dec. 25, resulting in PJM going into Dec. 25 in an EEA-1.

Dec. 25 and Dec. 26

On Dec. 25, a Sunday, PJM still had very high loads for a Christmas operating day. The morning peak was approximately 117,000 MW. There was sufficient capacity available to meet this morning peak as well as the evening peak, and PJM returned to EEA-0 at 22:00. **Figure 15** presents the PJM emergency procedures, as well as the load for Dec. 24 at 22:00 to Dec. 26 at 23:00.

Figure 15. Dec. 25 and Dec. 26 Emergency Procedures



At 11:10 on Dec. 25, PJM issued a Cold Weather Alert for the Western Region zones only from 07:00 Dec. 25 to 23:00 Dec. 26. At 23:00 on Dec. 26, the Cold Weather Alert ended.

Figure 16 summarizes the emergency alerts, warnings and actions PJM implemented from Dec. 23 through Dec. 26.

Figure 16. Summary of Alerts, Warnings, and Actions Issued on Dec. 23, Dec. 24 and Dec. 25

Action | Warning | Alert | Advisory

MESSAGE TYPE	DEC. 20	DEC. 21	DEC. 22	DEC. 23	DEC. 24	DEC. 25
Cold Weather Advisory			1	1	1	1
Cold Weather Alert				1	1	1
Emergency Load Mgmt Reduction Action				2	3	
Maximum Generation Emergency Action				1	1	
Maximum Generation Emergency/Load Management Alert				1	2	1
Non-Market Post Contingency Local Load Relief Warning	1	1		2	2	1
Post Contingency Local Load Relief Warning	3	3	1	25	26	6
Pre-Emergency Load Mgmt Reduction Action				2	3	
Synchronized Reserve Event				2	3	
Maximum Generation Emergency/Load Management Alert					1	
Voltage Reduction Warning and Reduction of NCPL					1	

As outlined in PJM Manual 13, Section 2.3: Capacity Shortages, “PJM dispatchers have the flexibility of implementing the emergency procedures in whatever order is required to ensure overall system reliability. PJM dispatchers have the flexibility to exit the emergency procedures in a different order than they are implemented when conditions necessitate.” As such, PJM Operations evaluated the usage and combination of any and all emergency procedures during Winter Storm Elliott in order to best maintain overall system reliability. While many emergency procedures were issues by PJM throughout the event, some were considered and ultimately not issued.

- **Cold Weather Alert** – While a Cold Weather Advisory was issued for the entire PJM RTO on Dec. 20 for the operating period of Dec. 23–26, PJM Operations did not declare a Cold Weather Alert for the entire RTO until the Dec. 24 operating day, opting only to declare a Cold Weather Alert for the Western PJM zones for the Dec. 23 operating day. PJM Operations forecasted the potential for cold weather starting on Dec. 23 and, as such, issued the appropriate advisory, while continuing to monitor forecasted temperatures leading up to the operating day. Per PJM Manual 13, Section 3.3.2 Cold Weather Alert, "as a general guide, PJM can initiate a Cold Weather Alert across the RTO or on a Control Zone basis when the forecasted weather conditions approach minimum or actual temperatures of 10 degrees Fahrenheit or below." Outside of the Western zones, temperatures were never forecasted to reach near a minimum of 10 degrees and instead were expected to be several degrees higher at their minimum. As such, it was not appropriate to issue a Cold Weather Alert for the zones outside of the PJM Western footprint until Dec. 24 when the trigger temperatures were forecasted.
- **Deploy All Resources Action** – The Deploy All Resources Action is a unique emergency procedure with a unique application. Its purpose is to immediately load all available generation and Demand Response following a severe system disturbance to attempt to halt frequency decay. This could lead to unintended loss of system control with regard to energy balance. It is only expected to be used as a means of last resort. This specific emergency procedure was discussed by PJM Operations and decided against implementing for several reasons, as implementing a Deploy All Resource Action could have aggravated some of the thermal and voltage constraints that were being managed. In addition, PJM Operations was manually controlling the output of all pumped hydro facilities during the event. Issuance of this emergency procedure would have removed PJM's controlling ability of these resources and instead would have immediately depleted the pond levels, which were needed to be precisely managed through the event.
- **Manual Load Dump Warning, Voltage Reduction Action & Manual Load Dump Action** – These three steps constitute the most severe emergency procedures that can be utilized to maintain reliability. While PJM Operations has these steps in the queue to issue, as necessary, system conditions never dictated a need to utilize them. During a conference call held with PJM Transmission Owners at 07:30 on Dec. 24, prior to the most challenging system conditions of the event, which was the Saturday, Dec. 24, morning peak, PJM management made a clear statement for the Transmission Owners to be prepared to respond as quickly as possible to any or all of these emergency procedures as there was the possibility that they could be issued imminently. PJM Operations kept the Voltage Reduction Action in reserve to deploy, if additional generation tripped offline. Per PJM Manual 13, this would have been approximately 1.3% of the RTO load at the time. If a Voltage Reduction Action were issued, it would have been immediately followed with a Manual Load Dump Warning and EEA-3 declaration, as a Manual Load Dump would have been the only remaining emergency procedure to maintain reliability. Then, if required, PJM would have been prepared to issue a Manual Load Dump Action. PJM was ultimately able to maintain reliability through the event without issuance of these three emergency procedures.

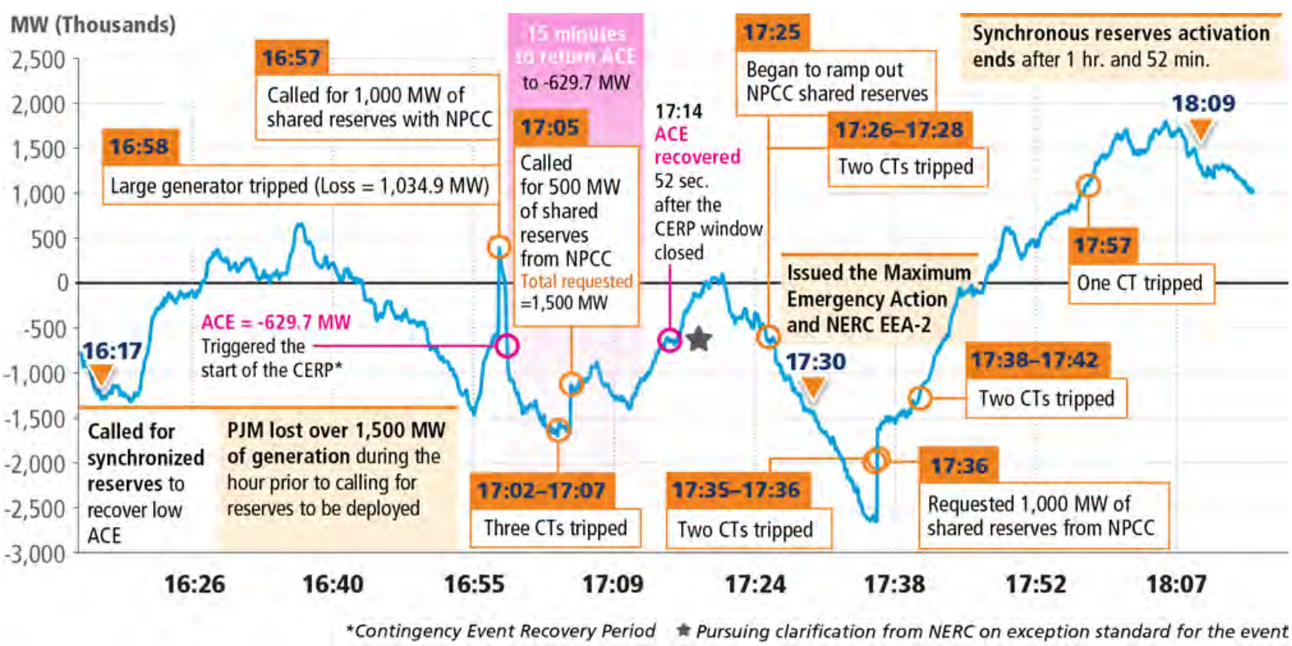
Disturbance Control Standard Event

The purpose of the NERC Standard BAL-002, Disturbance Control Performance, is to ensure that PJM, a NERC Balancing Authority, is able to utilize its contingency reserve to balance resources and demand, and to return interconnection frequency to within defined limits following a Reportable Disturbance. NERC defines a Reportable Disturbance as any event that causes an Area Control Error (ACE) change greater than or equal to 80% of a Balancing Authority's or reserve sharing group's most severe contingency. ACE is a measure of how well the Balancing Authority is matching generation to the load. If load and generation are perfectly balanced, the ACE is zero. When a generator within a Balancing Authority trips offline, the ACE goes down, and can go negative if it was already not above zero by a quantity at least as great as the output of the generator when it tripped. Because generator failures are far more common than significant losses of load and because contingency reserve activation does not typically apply to the loss of load, the application of Disturbance Control Standard (DCS) is limited to the loss of supply and does not apply to the loss of load.

PJM is required to have access to or operate with resource reserves to respond to disturbances. These reserves may be supplied from generation, controllable load, or coordinated adjustments to interchange schedules. The DCS Standard requires PJM to satisfy disturbance recovery criterion within a certain disturbance recovery period for 100% of Reportable Disturbances. The criterion requires PJM to return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the disturbance, a return of ACE is made to its pre-disturbance value. In either case, the disturbance recovery period is 15 minutes after the start of a Reportable Disturbance. Subsequently, PJM must fully restore the Synchronized Reserve within 90 minutes. All contingency losses (i.e., disturbances) with the lesser of 900 MW in the Eastern Interconnection or 80% of the Most Severe Single Contingency must be calculated and reported.

As described below, PJM was not able to recover the ACE within the prescribed 15 minutes. **Figure 17** presents PJM's ACE on the evening of Dec. 23 during the DCS event:

Figure 17. ACE During DCS



Heading into the evening peak on Dec. 23, load was increasing rapidly and PJM was ramping the generation fleet to keep up with the increasing load. Load was increasing quicker than PJM was able to ramp generation, and, as a result, the PJM ACE started to go negative. By 16:17 on Dec. 23, ACE was trending at around negative 1,000 MW, indicating low capacity. In response, PJM called for Synchronized Reserves to be loaded to recover from the low ACE. After approximately ten minutes, the ACE partially recovered but, by 16:40, went negative again. By 16:55, the ACE was approximately negative 1,500 MW. At 16:57, PJM called for 1,000 MW of shared reserves from NPCC. At that point, PJM's ACE was 429 MW as a result of PJM deploying reserves for approximately 40 minutes.

Approximately one minute following PJM's call for shared reserves from NPCC, a large generator in PJM tripped, losing approximately 1,035 MW. The Generation Owner reported that the generator was loaded at 850 MW at the time the unit tripped. The loss of this large generation resource was the initiating event with respect to the BAL-002 standard reporting event. Prior to the unit tripping, PJM's ACE was negative 630 MW. After the unit tripped, PJM's ACE dropped below negative 1,500 MW. Per the BAL-002 standard, PJM is required to recover ACE to negative 630 MW within15 minutes.

PJM had been deploying reserves since 16:17. Load on the system was continuing to increase. Between 17:02 and 17:07, additional generation tripped, and, as a result, the ACE continued to decline to approximately negative 1,600 MW. At 17:05, PJM called for an additional 500 MW of shared reserves from NPCC, bringing the total shared reserves from NPCC to 1,500 MW.

By 17:14, the PJM ACE had recovered back to negative 630 MW, ending the DCS event 15 minutes and 52 seconds after the large generator tripped. Although the DCS event had technically ended, controlling the ACE continued to be a challenge. As reflected in Figure 17, the PJM ACE climbed back to around zero about five minutes later but then went negative again. Throughout all of this, PJM continued to deploy reserves and was ramping whatever resources were online and available.

At 17:25, PJM started to ramp out the shared reserves from NPCC, which can only be relied upon for 30 minutes (recall PJM called for shared reserves at 16:57). As load continued to increase and additional generation was lost, the PJM ACE was approaching negative 3,000 MW by 17:34.

At 17:36, PJM requested 1,000 MW of shared reserves from NPCC again, which helped the ACE to begin to recover. The ACE continued to recover until 18:09, at which time PJM ended the call for Synchronized Reserves to be loaded, 1 hour and 52 minutes after PJM began deploying them.

During this period, PJM was ramping generation as quickly as possible and deploying Synchronized Reserves for almost two hours. By 18:00, the rate that the load was increasing slowed as PJM was beginning to see the impact of the Demand Response that was called at 17:30.

PJM evaluated compliance with the BAL-002 standard, and engaged in communications with ReliabilityFirst regarding the matter. This evaluation included the consideration that BAL-002-3 R1.3 provides scenarios in which Responsible Entities are not subject to compliance with BAL-002-3 R1.1, provided certain thresholds are met.

In response to the low response rate and lack of available reserves, PJM will be reviewing procedures to identify triggering conditions that will further increase the amount of reserves that are scheduled leading into the operating day. This will include triggers to potential increase the amount of the Synchronized, Primary and/or Operating Reserves scheduled in the Day-Ahead, RAC and Real-Time market clearing.

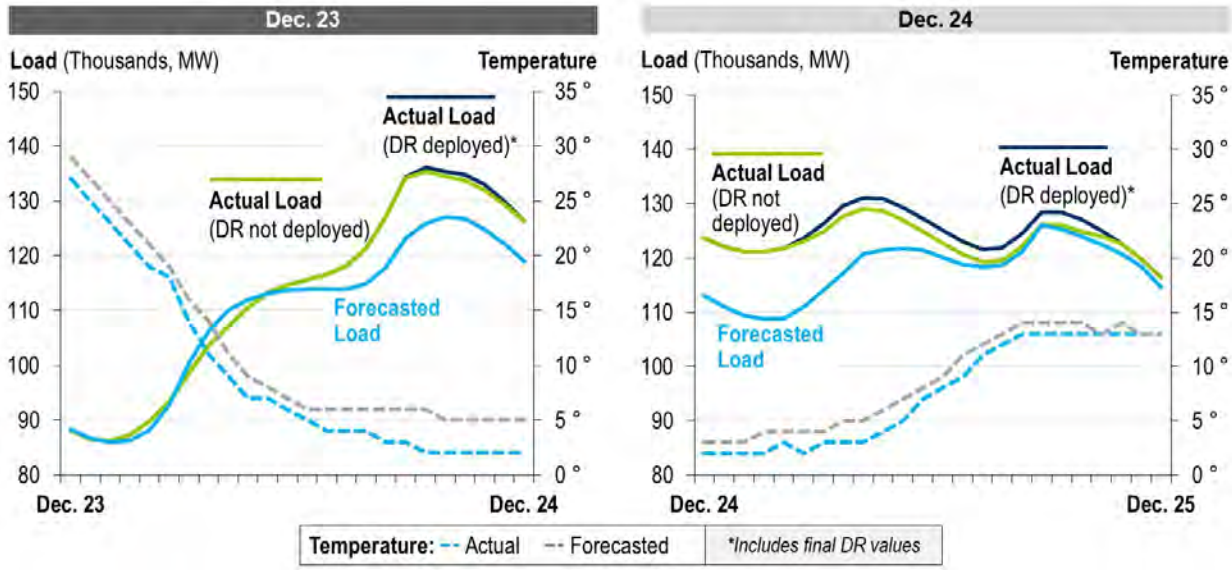
Load Forecast Versus Actual Load

The load forecasts for Dec. 23 and Dec. 24 presented a unique set of challenges. The winter holiday period has historically been a challenging time to forecast due to school vacations, business closures and atypical human behavior patterns, as presented in Figure 19. In the past, over-forecasting was more of an issue than under-forecasting, resulting in the PJM forecast team enhancing processes in recent years to correct for this over-forecasting trend. The winter 2022 holidays were further complicated by the extreme weather and Christmas Eve occurring on a Saturday, which had not occurred since 2016.

On Dec. 23, the forecasted peak load was 126,968 MW, and the actual peak was 136,010 MW, which included Demand Response added back into the load. On Dec. 24, the forecasted peak load was 121,723 MW, and the actual peak was

131,113 MW, which included Demand Response added back into load. On both Dec. 23 and Dec. 24, the actual load came in well higher than forecast, as presented in **Figure 18**.

Figure 18. Dec. 23 and Dec. 24 Actual Load



The high demand for electricity continued after the peak on Dec. 23 and into Dec. 24. The actual valley load, or low point of demand, on Dec. 24 was significantly greater than originally forecasted as well. The Dec. 24 valley load was higher than any other peak, or high point of demand, for that date over the previous decade, as shown in **Figure 19**, which presents the holiday load for 2022 and the previous 10 years.

Figure 19. Holiday Load for Previous 10 Years

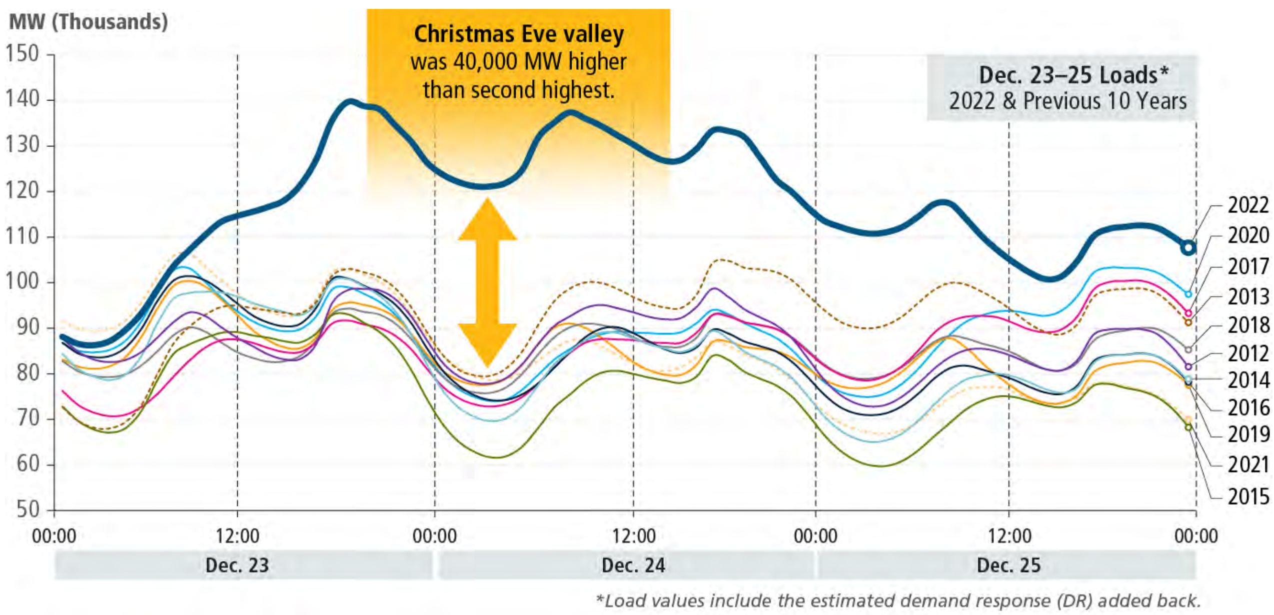
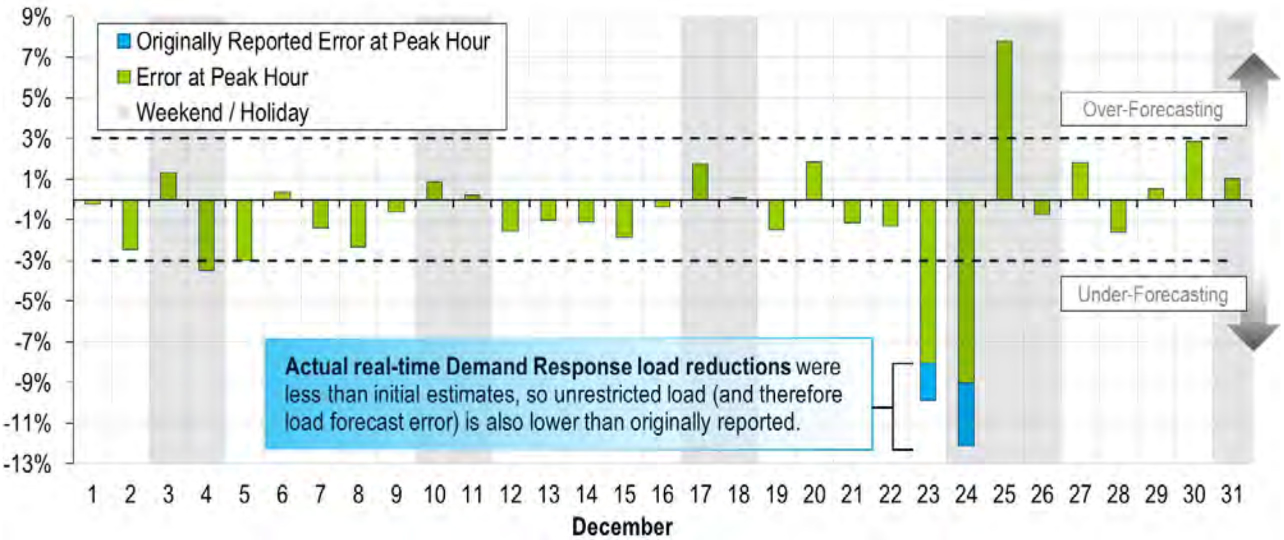


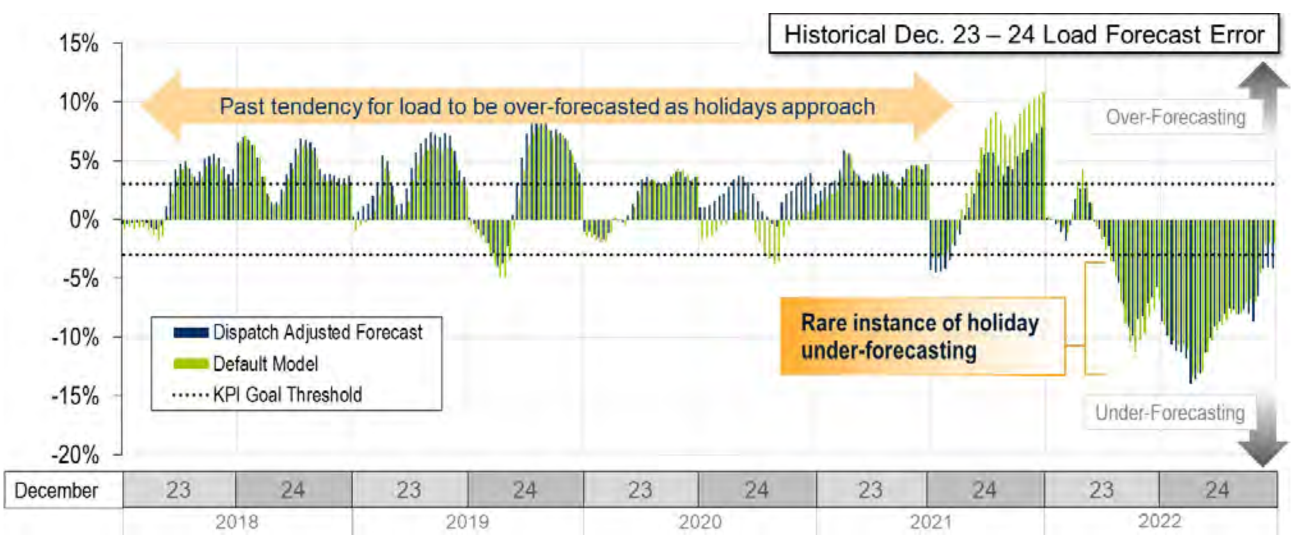
Figure 20 presents graphic presents the daily peak forecast error for December.

Figure 20. December Daily Peak Load Forecast Error



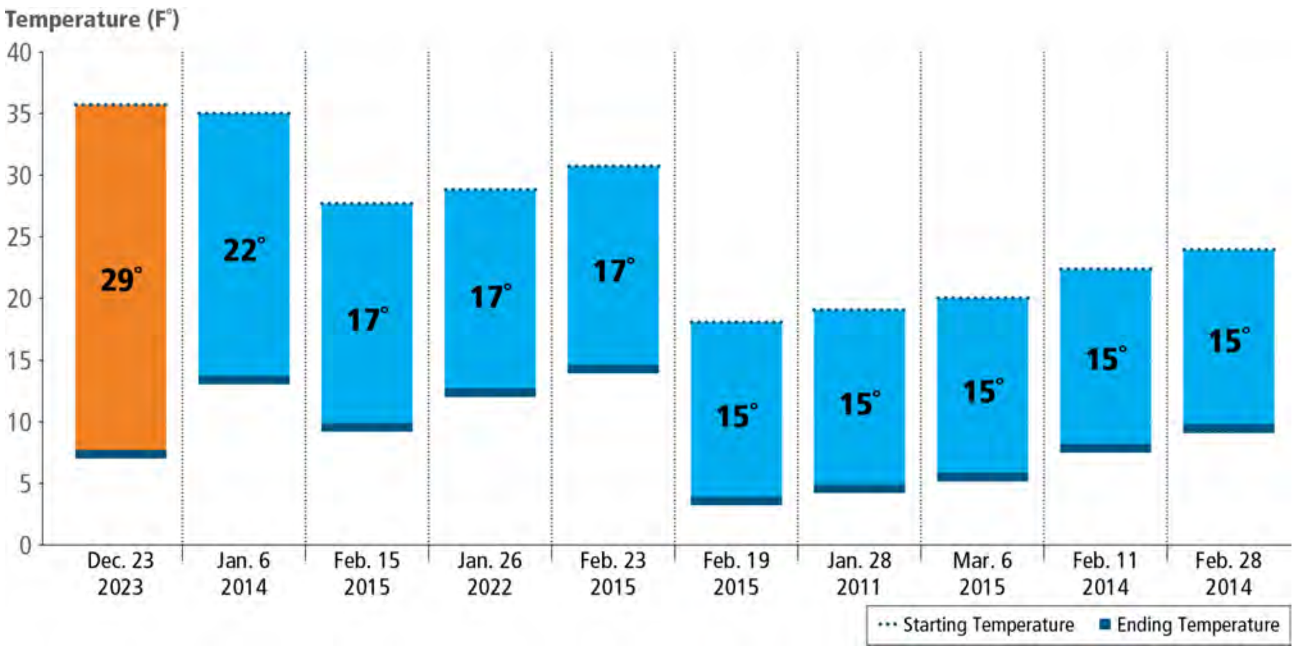
The extreme weather not only included bitter cold temperatures that were outside of the data sample used to train the load forecast models (mid-2019 to mid-2022), but also a rapid temperature drop, strong winds, heavy icing and snowfall, all of which occurred unusually early in this winter. Figure 21 presents the historical load forecast error the past five years.

Figure 21. Historical Dec. 23–24 Load Forecast Error



The load forecast is determined by an algorithm that considers expected weather conditions, day of the week and holidays. The model had not been exposed to the conditions that occurred on Dec. 23, with the confluence of unprecedented cold temperature drops, the holiday and the weekend. Within the PJM footprint, the difference between the high and low temperatures on Dec. 23 was one of the greatest in recorded history, as shown in the Figure 22.

Figure 22. Dec. 23 High and Low Temperatures



In Figure 22, the top and bottom of each bar represent the starting and ending temperature for each day, respectively.

The following primary drivers contributed to the load forecast error observed on Dec. 23 and 24:

- Extreme weather – severe cold and blizzard conditions, the most drastic temperature drop in at least 10 years, and early occurrence of cold weather
- Holiday impacts, which usually result in lower demand levels than normal

While PJM uses a sophisticated set of load forecasting tools and processes, we believe the Dec. 23 and 24 load forecasts highlight a case where two simultaneous conditions, a holiday and extreme weather with very limited analogous history, occurred together to produce atypically large forecast errors. PJM is already engaged with an independent party to further investigate enhancements to the load forecasting process, in general, and related to these specific events.

Emergency Generation and Demand Response Performance

Altogether, a Maximum Generation Action, Demand Response and public Call for Conservation helped address challenging operating conditions on Dec. 23 and 24. This section discusses information regarding the use of emergency resources. Information regarding the Call for Conservation is presented in the Government, Member & Media Outreach section.

PJM issued a Max Generation Action on Dec. 23 between 17:30 and 22:00 and observed a total increase of approximately 2,300 MW as a result of generation resources operating between their economic maximum and emergency maximum limits. Similarly on Dec. 24, PJM issued a Max Generation Action between 04:30 and 22:00 and observed a total increase of approximately 2,800 MW as a result of generation resources operating between their economic maximum and emergency maximum limits.

Demand Response was used to reduce peak loads in the entire PJM region during the winter storm. PJM called on Demand Response two times to address operational challenges with capacity shortages.

As described previously, PJM called for Demand Response on Dec. 23, which was to be implemented by 18:00. Demand Response with a capacity commitment is referred to as Load Management, which is comprised of Pre-Emergency and Emergency Demand Response. Load Management is required to reduce or maintain load at or below the committed value based on PJM dispatch within 30 minutes (quick lead time), 60 minutes (short lead time), or 120 minutes (long lead time). Based on the expected peak for the day, PJM dispatched both the 30-minute and the 60-minute lead resources on the evening of Dec. 23.

In total, PJM dispatched what it anticipated to be 4,336 MW of Load Management on Dec. 23 with 4,007 MW of 30-minute lead resources by 18:00 and another 329 MW of 60-minute lead resources by 18:30. In real-time, Curtailment Service Providers (CSPs) are required to provide estimates of their load reduction capability to PJM since customer load may already be low for other reasons (public appeal to reduce load, normal operating conditions, etc.). These estimates are intended to give PJM operators a quantity of load that will reduce if they deploy a specific category of Load Management. CSPs estimated, and therefore PJM expected, that 4,336 MW of load would be reduced based on the deployment on Dec. 23. PJM estimates, based on after-the-fact customer load data, that actual load reductions were approximately 1,100 MW. In total on Dec. 23, approximately 74% of the Demand Response that PJM operators dispatched and expected to reduce load did not.

As PJM was approaching the morning peak on Dec. 24, given the critical capacity condition, PJM system operators dispatched all Load Management with a total capacity commitment of 7,522 MW at 04:20.

4,007 MW of 30-minute Demand Response was expected to respond at 06:00.	329 MW of 60-minute Demand Response was expected to respond by 06:00.	3,186 MW of 120-minute Demand Response was expected to respond by 06:20.

CSPs estimated, and therefore PJM expected, that approximately 7,400 MW of load would be reduced. Based on after-the-fact customer load data, PJM estimates that actual load reductions from PJM dispatch was approximately 2,400 MW. This corresponds to approximately 68% of the Demand Response PJM operators dispatched and expected to reduce load not performing.

The significant difference between the data provided to PJM about load curtailment capability and the actual performance clearly identify an opportunity and need to improve the rules and processes regarding Load Management capability estimates.

Real-Time Interchange

Interchange transactions take the form of an import, meaning market participants purchase power from a neighboring area and sell into PJM, an export, where power is purchased from PJM and sold to an external area, or a wheel, where power is simultaneously purchased from a neighboring area, scheduled across PJM, and then sold to an external area. PJM is typically a net exporter of energy to neighboring systems, and that remained true in the days preceding Winter Storm Elliott. With this information in mind, PJM operators took a conservative stance in preparing for the Dec. 23 and Dec. 24 operating day and planned for sufficient reserves to meet both forecast internal load and the needs of neighboring systems who rely on support from PJM in the form of interchange transactions and emergency purchases.

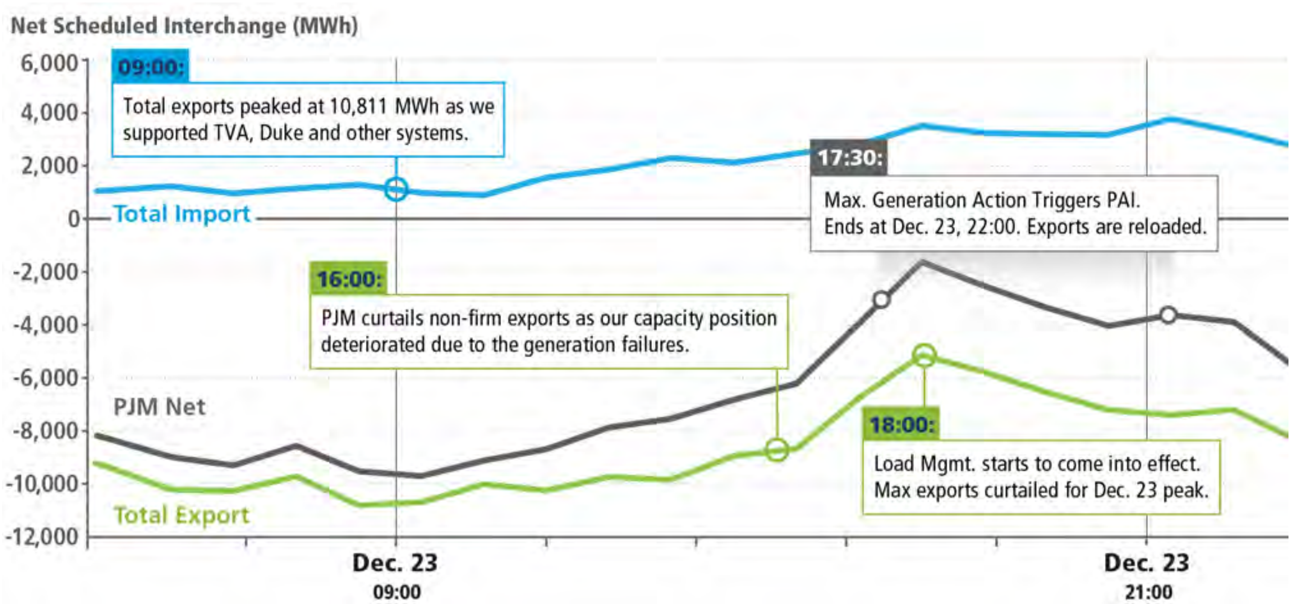
As PJM made the decision to issue Cold Weather Advisories and Alerts for these operating days, the bitter cold temperatures traveled across the country from the north and west to the south and east. Early in the day on Dec. 23, areas to PJM's west and south were already experiencing bitter cold temperatures. PJM was exporting energy throughout the morning and early afternoon on that day. Throughout the Dec. 23 to 24 period, PJM was balancing the extremely tight capacity situation due to the unprecedented amount of generator trippings and forced outages, controlling flows on the AEP-Dominion IROL[5] interface, as well as the extreme system conditions faced by our neighbors to the south.

Dec. 23

At the start of Dec. 23, PJM exported over 8,000 MWh for the hour ending 01:00 and increased that amount over the morning hours to reach almost 11,000 MWh for the hour ending 10:00 (Figure 23). These exports included the supply of emergency energy to TVA during the hours ending 07:00 through 11:00. During hour-ending 13:00, exports started a slight downward trend, and as PJM's capacity position continued to deteriorate, non-firm exports to adjacent areas were ultimately curtailed via a Maximum Generation Emergency Action. PJM system operators initiated the curtailment of non-firm export transactions at hour ending 17:00 by limiting roughly 400 MWh of exports, and quickly jumped to limiting well over 3,000 MWh of transactions each hour from hours ending 18:00 through 20:00. At that point, PJM system operators began a transition out from the heaviest Maximum Generation curtailments, with most transactions resuming full flow by hour-ending 22:00. In anticipation of, and in response to the Minimum Generation Action on Dec. 23, PJM curtailed in total almost 14,000 MWh of exports.

Figure 23 presents the Net Scheduled Interchange on Dec. 23.

Figure 23. Dec. 23 Net Scheduled Interchange



Dec. 24

When current and forecast system conditions indicated reduced availability to support exports on Dec. 24, the Transmission Load Relief (TLR) mechanism was considered as an option to provide relief for the AEP-Dominion IROL interface; however, the resulting analysis showed the need for an excessive volume of tag[6] curtailments on neighboring

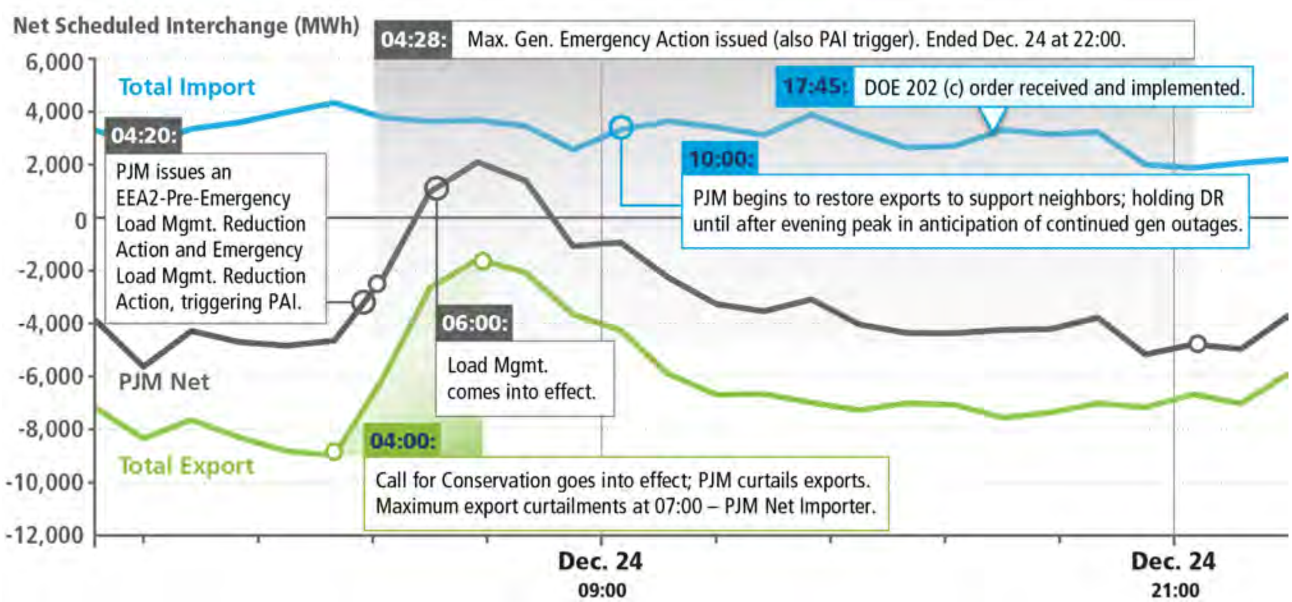
[5] Interconnection Reliability Operating Limit (IROL) is a system operating limit that, if exceeded, could lead to system instability, uncontrolled separation, or cascading that adversely impact the reliability of the bulk electric system.
[6] A tag is information describing a physical Interchange Transaction or Intra-BA Transaction and its participant.

systems that were already experiencing significant issues of their own. PJM system operators concluded that issuing a TLR would create far-reaching impacts across the Eastern Interconnection and likely make system conditions and emergencies worse for our neighbors. PJM also elected to limit curtailment of exports over the midnight period knowing the severe system conditions of our neighbors to the south. This limited PJM's ability to pump hydro stations.

Facing both a capacity emergency and lack of controlling options for AEP-DOM, PJM made the decision to take a more surgical approach and initiated curtailments in anticipation of a Maximum Generation Emergency Action, which was ultimately declared at 04:25. PJM system operators began limiting non-firm exports in hour ending 05:00 and increased the magnitude of curtailments by hour ending 06:00 when they had also begun limit firm exports. The most significant curtailments occurred in hour ending 08:00 with over 4,000 MWh of firm transactions limited and over 5,000 MWh of non-firm exports limited. Both PJM and its capacity deficient neighbors were experiencing peak loads at the same time, and PJM did not have excess capacity to support export requests regardless of the supporting transmission service priority. After the morning peak load, PJM slowly started to lift the limits on exports; however, the duration of this event was much longer than that seen on Dec. 23, with firm curtailments persisting until 12:00 and non-firm curtailments persisting until 15:00. For the event on Dec. 24, PJM curtailed over 45,000 MWh of export transactions. Conversely, PJM observed over 40,000 MWh of import transaction curtailments on Dec. 24, primarily resulting from TLRs issued by neighboring Reliability Coordinators (RCs). At the peak of the curtailments, PJM briefly transitioned to an overall net-importer of energy for several hours on the Dec. 24, with a net schedule of approximately 2,800 MWh into the footprint for hour ending 08:00.

Figure 24 presents the Net Scheduled Interchange on Dec. 24.

Figure 24. Dec. 24 Net Scheduled Interchange

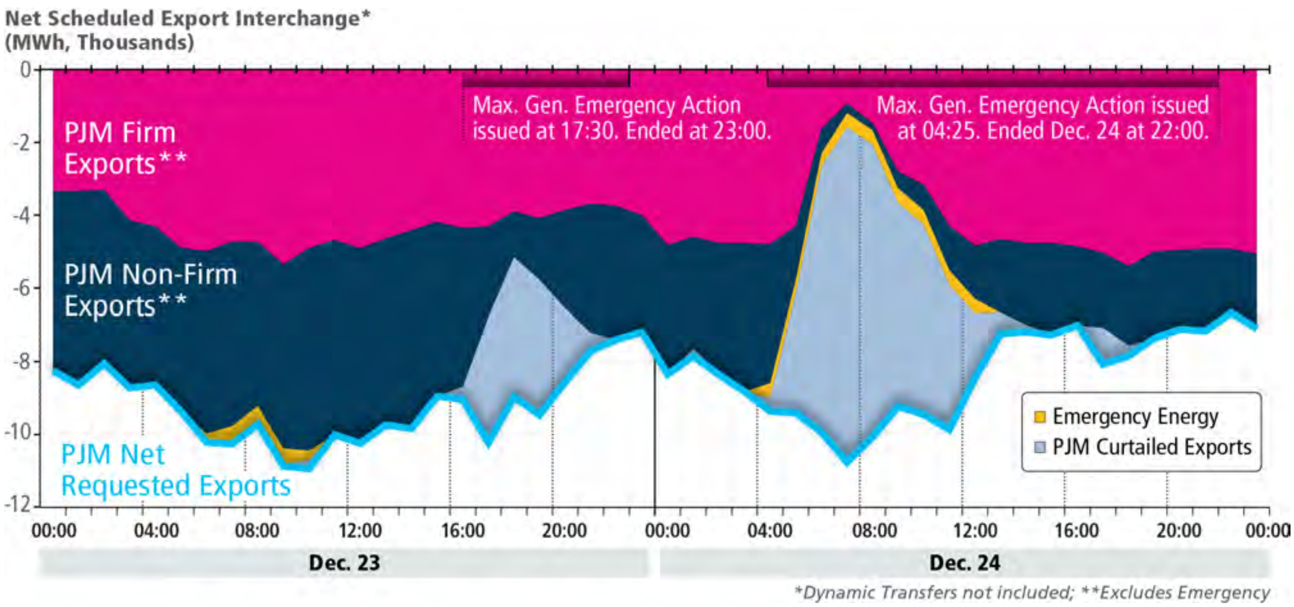


Coordination With Neighbors

As the extreme cold temperatures moved through areas to the southwest of the PJM footprint, neighboring systems began to experience strains. On both Dec. 23 and Dec. 24, PJM coordinated closely with its neighbors to maximize transfers. PJM provided emergency energy to adjacent systems as system conditions allowed on both Dec. 23 and Dec. 24 (Figure 25) before eventually having to reduce exports in order to serve consumers within the PJM footprint.

Transmission constraints also limited PJM's ability to support export transactions across the southern interfaces. These constraints included the pre-contingency emergency thermal limit of the Broadford 765/138 kV transformer and post-contingency transfer limit of the AEP-Dominion IROL interface. Figure 25 presents the Net Scheduled Exports for Dec. 23 through Dec. 24.

Figure 25. Dec. 23 and Dec. 24 Net Scheduled Exports



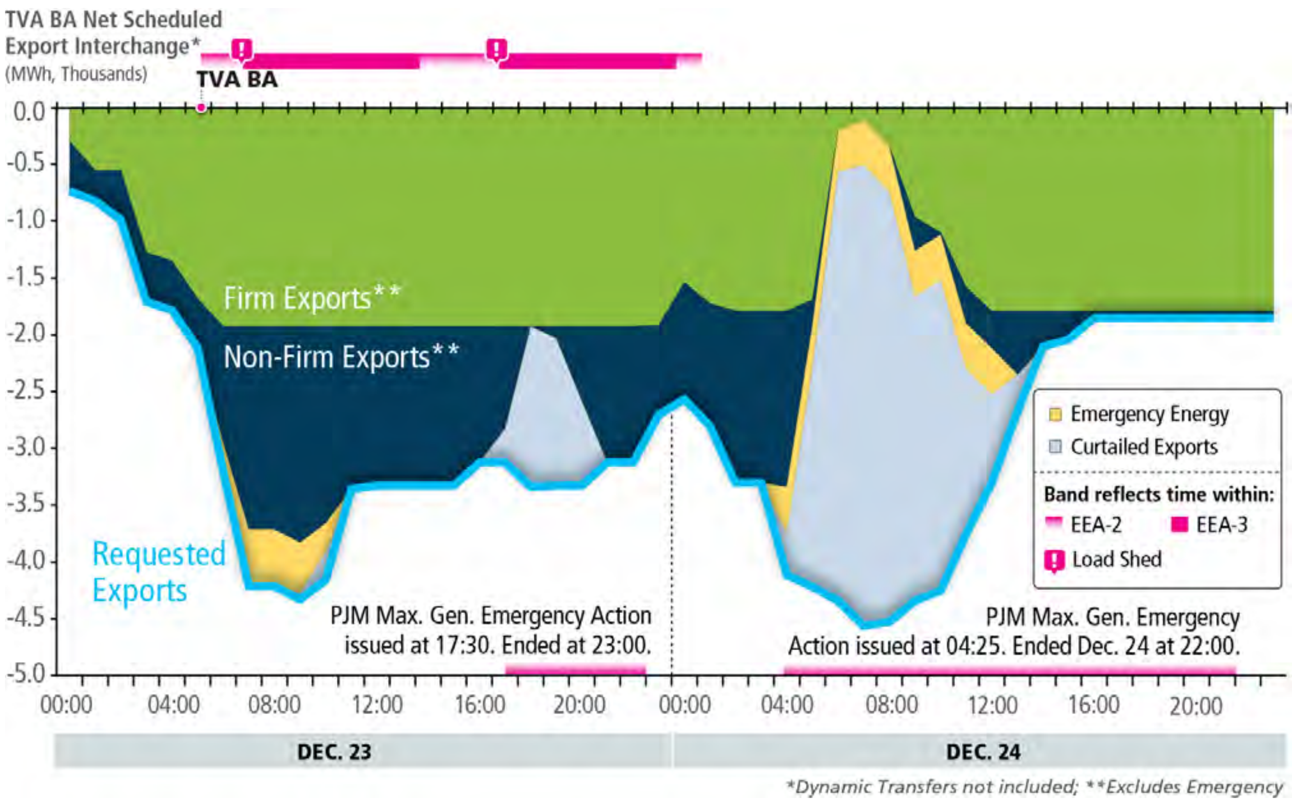
Comparing the values in Figure 25 to the supply/demand conditions that PJM actually experienced confirms that PJM could not have met system demand only by cutting non-firm exports. On Dec. 23, 2022, at 17:30, PJM issued a Pre-Emergency Load Management Reduction Action for the 30-minute and 60-minute Demand Resources that resulted in load reductions of about 1,100 MW. At the same time, PJM system operators also issued a Maximum Generation Emergency Action that resulted in an average of 2,372 MW of additional generation. In total, these actions had about 3,472 MW of impact. In comparison, non-firm exports were 1,241 MW for hour 18:00 and were 1,683 MWs for hour 19:00. Accordingly, even if the operators had cut all non-firm exports, there would have been a deficit of at least 1,789 MW needed to satisfy PJM load and firm exports. Pre-Emergency and Emergency Actions thus would have been necessary to satisfy capacity needs even if all non-firm exports had been cut.

The situation for Dec. 24 is similar. At 04:20, PJM issued a Pre-Emergency Load Management Reduction Action and an Emergency Load Management Reduction Action that covered all Demand Resources and resulted in about 2,400 MW of load reduction. And at 04:28, PJM issued a Maximum Generation Emergency Action that it resulted in an average of about 2,879 MW in additional generation. In total, these actions had 5,279 MW of impact. In comparison, for hour 05:00, non-firm exports were 1,820 MW, falling to a low of 591 MW in hour 8:00 and increasing to a maximum level of 2,359 MW in hour 19:00 before the PAIs ended at 22:00. Accordingly, even if the PJM system operators had cut all non-firm exports there would have been a deficit between about 4,688 MW and 2,920 MW during this period needed to satisfy PJM load and firm exports. Pre-Emergency and Emergency Actions thus would have been necessary even if all non-firm exports had been cut.

Figure 25 also shows that PJM prioritized meeting its own load by cutting exports – both firm and non-firm – when necessary. The graph shows a significant number of hours in which the assistance requested by other regions was not supplied. This correlates to the periods when PJM needed most of its generation for internal loads notwithstanding that, during some of these times, other regions were seeking emergency supplies.

As presented in **Figure 26**, PJM was able to assist TVA by providing non-firm exports during times that the TVA system was shedding load, which is represented by the fuchsia bars indicating when TVA was in an EEA-2 or EEA-3. Had PJM not done so, it is likely that TVA would have been required to engage in additional load shedding beyond what actually occurred.

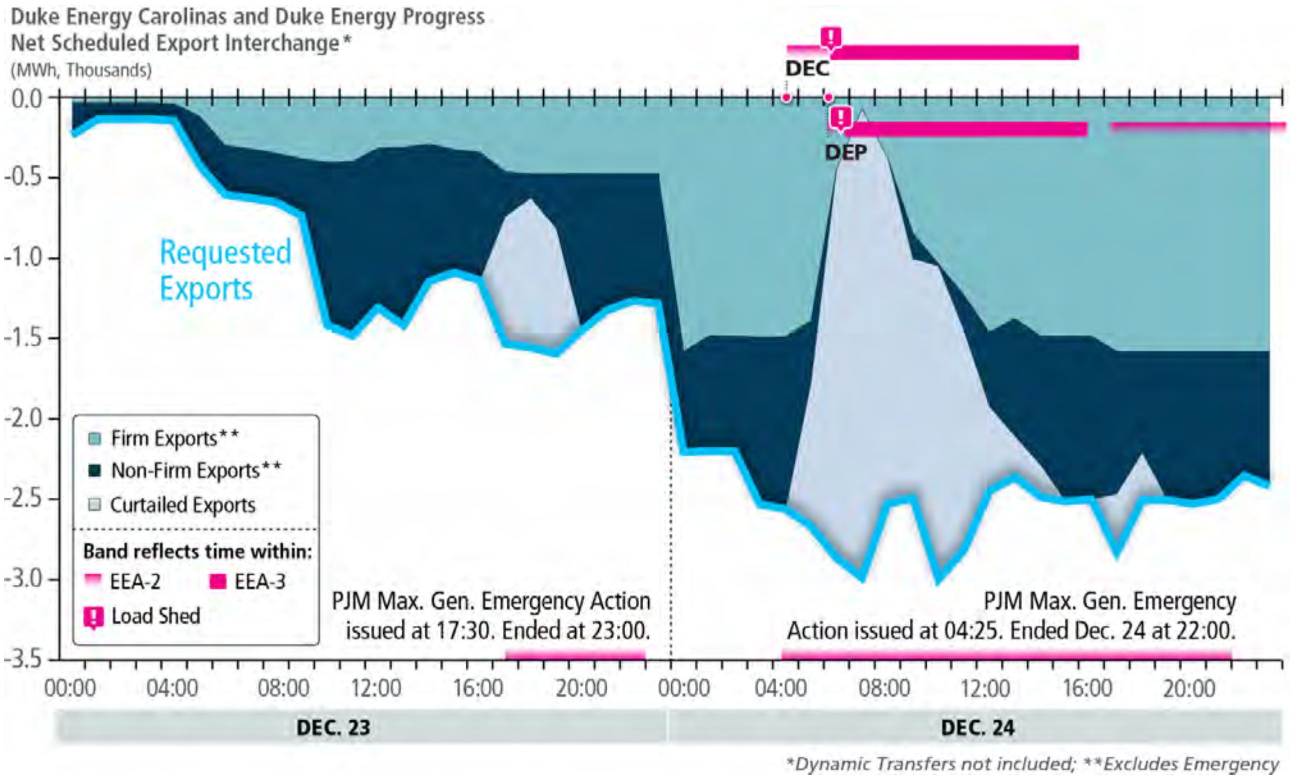
Figure 26. TVA BA Net Scheduled Export Exchange



The non-firm exports supplied to TVA provided assistance during periods when TVA was in a capacity deficient condition.

Similarly, the non-firm exports supplied to Duke Carolinas and Duke Energy Progress provided assistance to those systems when they were experiencing capacity deficient conditions as shown in the **Figure 27**.

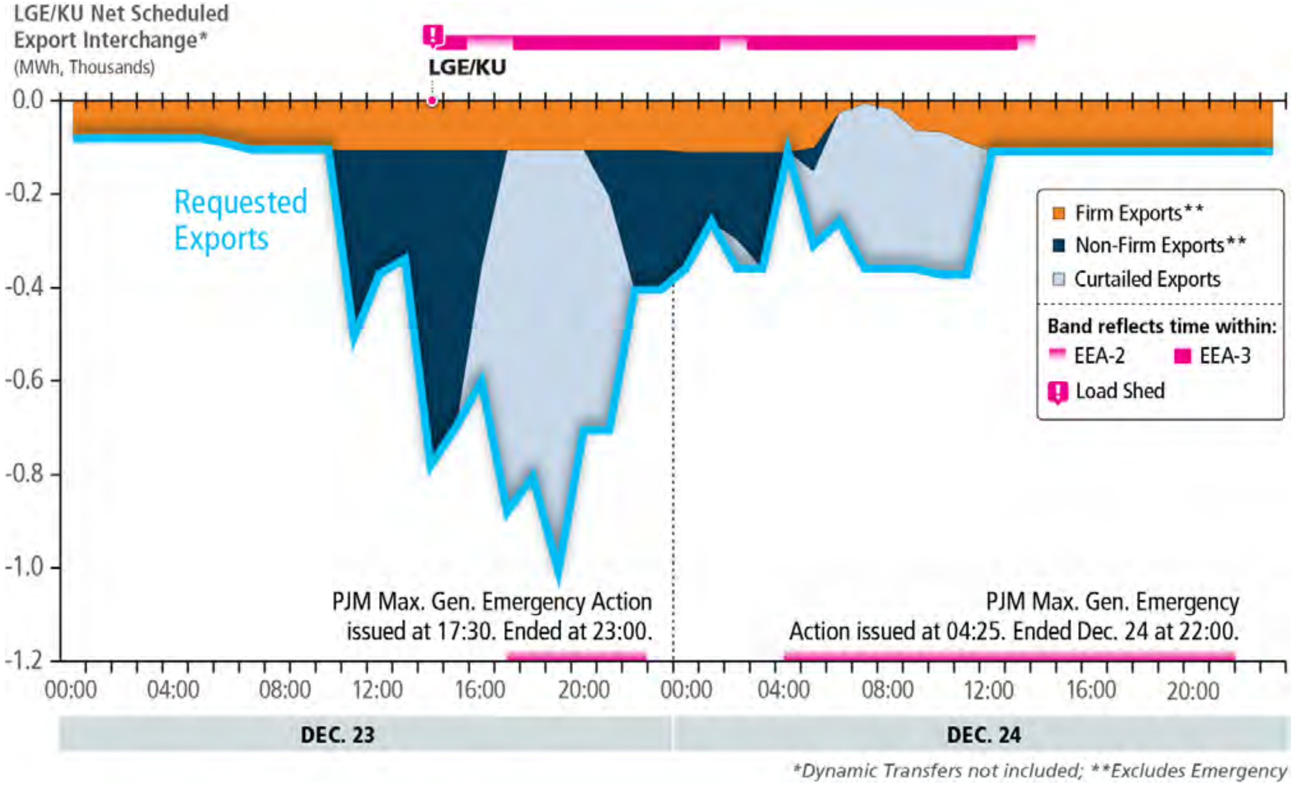
Figure 27. Duke Energy Carolinas & Duke Energy Progress Net Scheduled Export Interchange



As presented in Figure 27, PJM was also able to provide assistance by supplying non-firm exports to Duke Carolinas and Duke Energy Progress when they were shedding load. Again, if PJM had not provided this assistance, it is likely that Duke Carolinas and Duke Energy Progress would also have had to engage in more load shedding.

Lastly, Louisville Gas and Electric Company and Kentucky Utilities Company (LGE/KU) also received non-firm exports when they were experiencing capacity deficit conditions as shown in Figure 28.

Figure 28. LGE/KU Net Scheduled Export Interchange



PJM made non-firm deliveries to LGE/KU when the region was shedding load. Had PJM not made these exports, additional load shedding would likely have been needed.

Generation Performance

Prior to the operating day and Winter Storm Elliott, PJM had issued both Cold Weather Advisories and Cold Weather Alerts. Both procedures notify Generation Owners, Transmission Owners, and all PJM members of impending cold temperatures and to take action. Specifically, Generation Owners must take freeze protection actions, notify PJM of any operational changes or limitations as a result of the imminent cold weather, and update the operational parameters of generation units in Markets Gateway. These unit parameters include the Start-up and Notification Time, Min Run Time, Max Run Time, Eco Min, Eco Max, etc. Having accurate information about these unit parameters, in particular any changes to the start-up and notification times, are critical to PJM's decision making with respect to when a unit is given a commitment to run (i.e., when it is scheduled by PJM). PJM Dispatchers and their tools rely heavily on offer data information submitted by resource owner/operators. Given that 92% of forced outages that occurred were reported to PJM either after they occurred or with less than 60-minutes notice, it suggests that this information was not maintained throughout the event.

PJM started the operating day of Dec. 23 with 12,000 MW of unplanned outages, 4,293 MW of planned outages and 1,692 MW of maintenance outages at the evening peak on Dec. 23. These outages were primarily due to various equipment problems at generation facilities. PJM was tracking the cold temperatures arriving as a result of Winter Storm

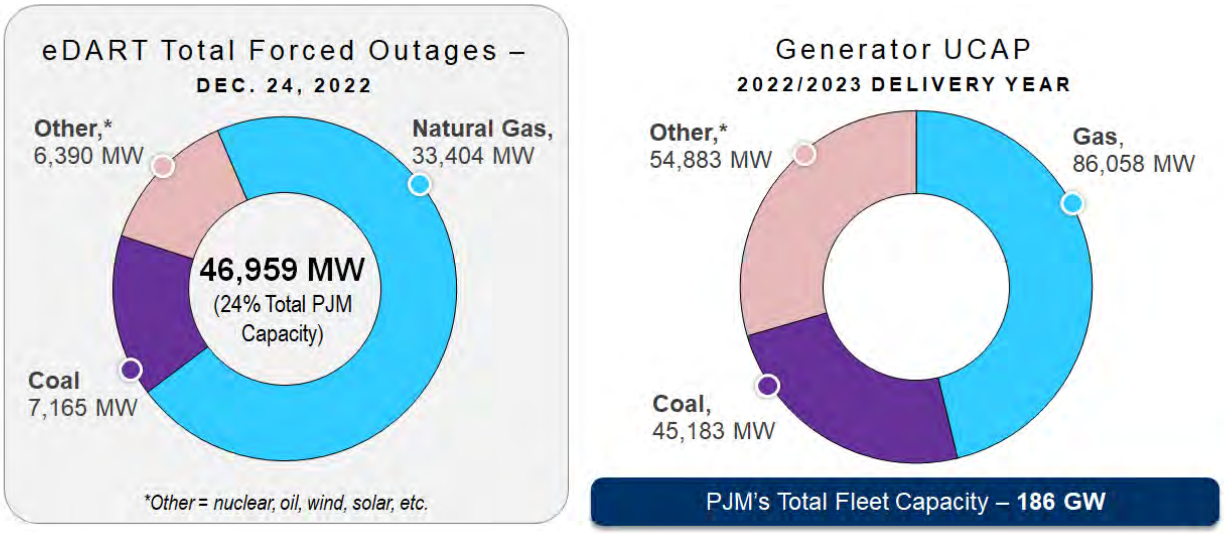
Elliott and did expect additional unplanned generation outages. For reference, the historic forced outage rate for winter is ~4.7%. The peak outage rate for the 2020/2021 winter period was 7.9%[7] and was 7.6%[8] for the 2021/2022 winter period.

While many generators performed well, the overall outage rate was unacceptably high. PJM had approximately 47,000 MW of units on forced outages during the hours when they were most needed. This correlates to a 24% forced outage rate. For comparison, the forced outage rate during the 2013 Polar Vortex was 22%. While a cross section of generation was impacted by the cold weather, gas plants and dual-fuel gas plants made up the majority of outages primarily due to mechanical issues likely resulting from the extreme cold.

Forced Outage Analysis

As presented in **Figure 29**, the majority of forced outage MW were from natural gas facilities. Approximately 70% of all outages were natural gas, about 16% coal, and the remainder were oil, nuclear, hydro, wind and solar.

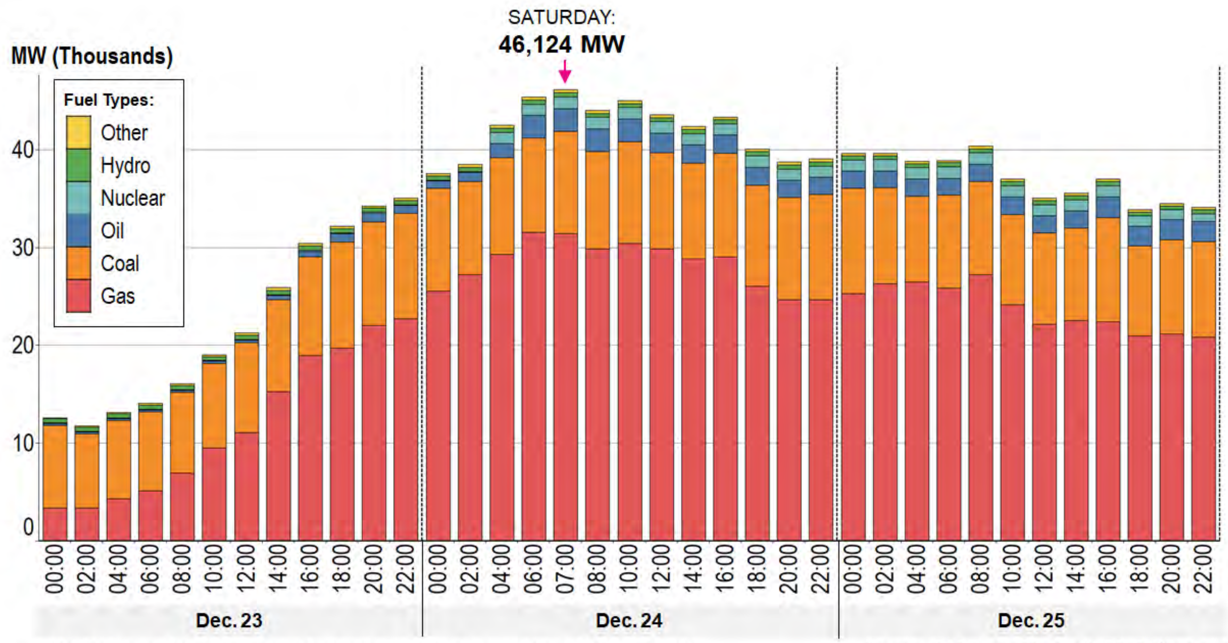
Figure 29. Forced Outages



As shown in the **Figure 30**, forced outages increased significantly and quickly throughout the day on Dec. 23 and peaked at over 46,000 MW at 07:00 on Dec. 24. Even as forced outage rates declined from the peak, they remained at an unacceptably high level through Dec. 25.

[7] Winter Operations of the PJM Grid: Dec. 1, 2020 – Feb. 28, 2021, PJM Operating Committee, April 8, 2021
[8] Winter Operations of the PJM Grid: Dec. 1, 2021 – Feb. 28, 2022, PJM Operating Committee, April 14, 2022

Figure 30. Dec. 23 and Dec. 24 Forced Outages

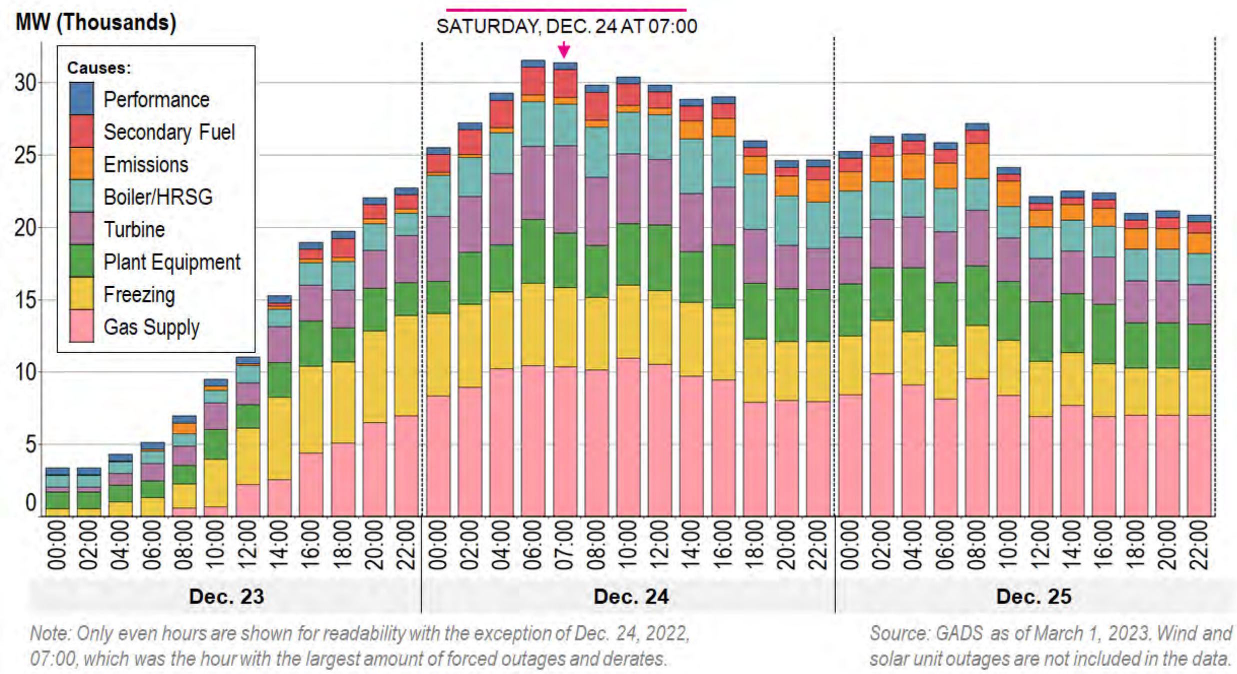


Note: Only even hours are shown for readability with the exception of Dec. 24, 2022, 07:00, which was the hour with the largest amount of forced outages and derates.

Source: GADS as of March 1, 2023. Wind and solar unit outages are not included in the data.

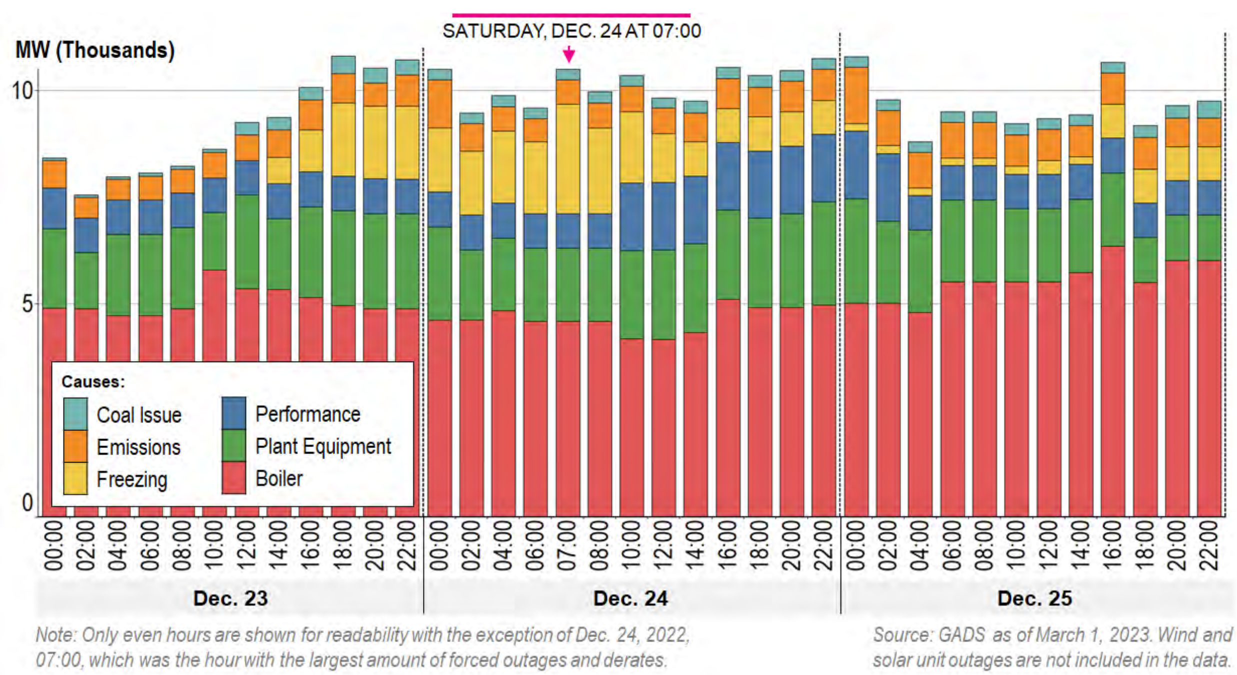
Looking more closely at the causes for the generation outages by fuel type indicates that various plant and mechanical failures, including freeze-related issues, were the major reasons units were unavailable. **Figure 31** presents the gas unit forced outages. As with other resource types, outages on gas units were primarily attributed to physical plant issues (freezing and plant equipment issues), but gas generators also experienced a significant level of gas supply issues. The gas supply-related outages accounted for just over 11,000 MW (approximately 13% of total gas generation capacity) at the peak hour on Dec. 24. By contrast, during the 2014 Polar Vortex, the total gas resources that were unavailable on peak due to gas supply issues was 9,300 MW (approximately 19% of total gas generation capacity).

Figure 31. Dec. 23, 24 and 25 Gas – Forced Outages/Derates by Cause



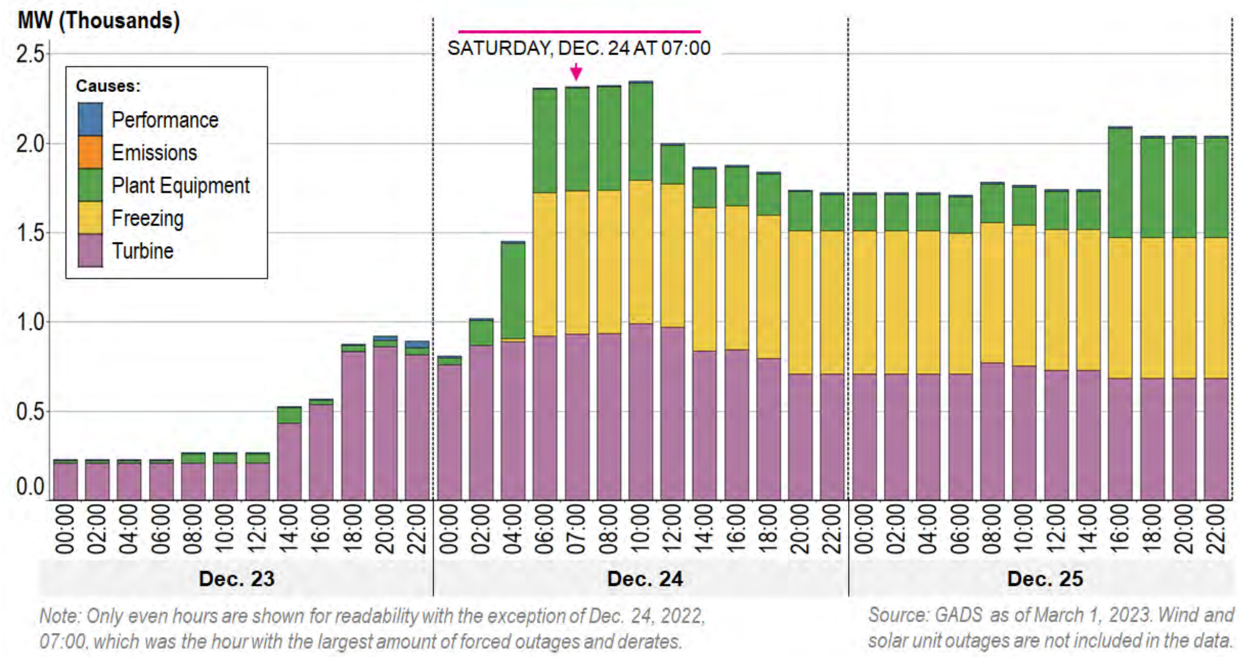
As presented in **Figure 32**, for coal units, boiler problems and tube leaks were the primary cause of outages and derates followed by other plant equipment issues. Freezing issues increased starting around 14:00 on Dec. 23 and peaked at approximately 07:00 on Dec. 24.

Figure 32. Dec. 23, 24 and 25 Coal Forced Outages/Derates by Cause



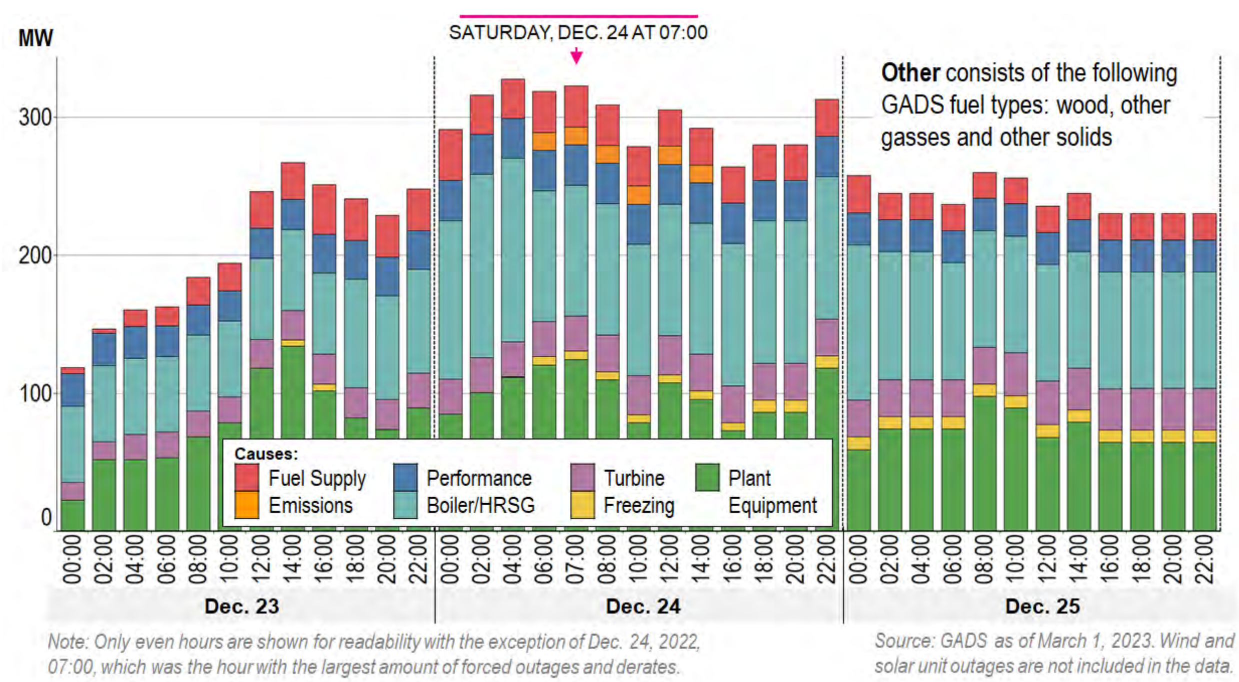
As shown in **Figure 33**, for oil units, turbine issues accounted for a large majority of the outages. A significant amount of freeze-related outages and derates were experienced from 06:00 on Dec. 24, and continued throughout the day on Dec. 25.

Figure 33. Dec. 23, 24 and 25 Oil Forced Outages/Derates by Cause



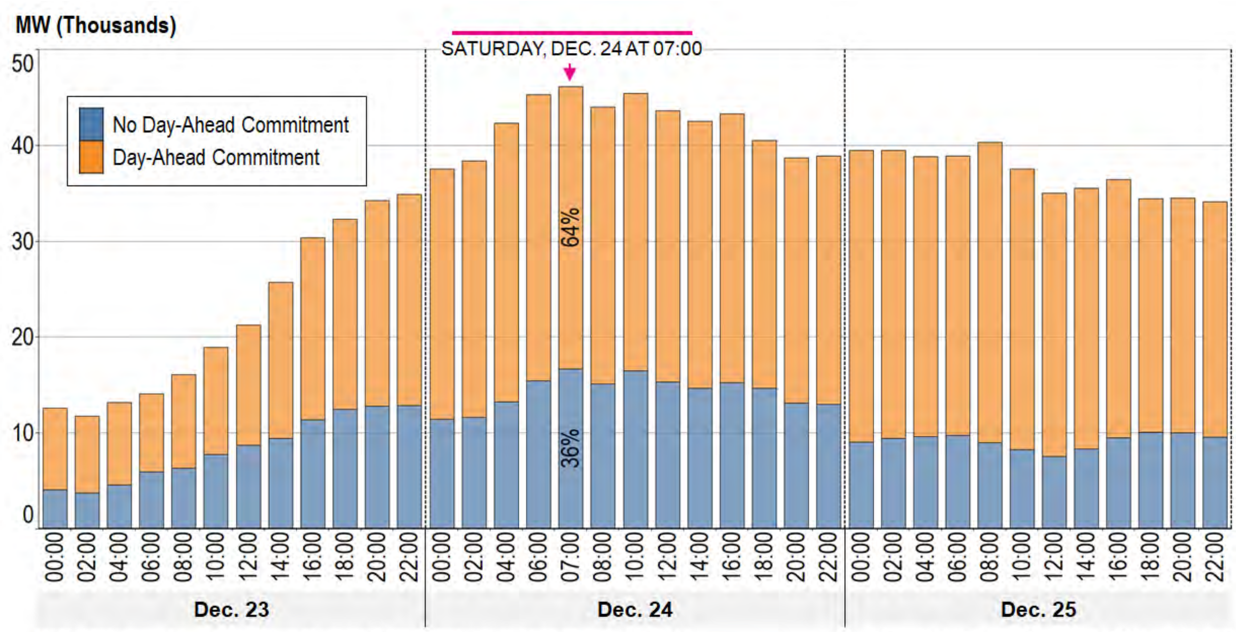
As presented in **Figure 34**, for generators fueled by wood, other gases or other solids, most outages/derates were attributed boiler, HRSG and other plant equipment problems.

Figure 34. Dec. 23, 24 and 25 Other – Forced Outages/Derates by Cause



In addition to the causes of the forced outages and the outages by fuel type, Figure 35 presents the outages for units based on day-ahead commitments. This is an important piece of the puzzle to understand with respect to PJM's planning for the operating day. PJM always expects some resources will fail. On cold weather days in particular, this is considered and noted in PJM Manual 13. However, as Figure 35 shows, over 16,000 MW of generation that was committed in the Day-Ahead Market failed to perform.

Figure 35. Dec. 23, 24 and 25 Forced Outages With and Without Day-Ahead Market Commitment



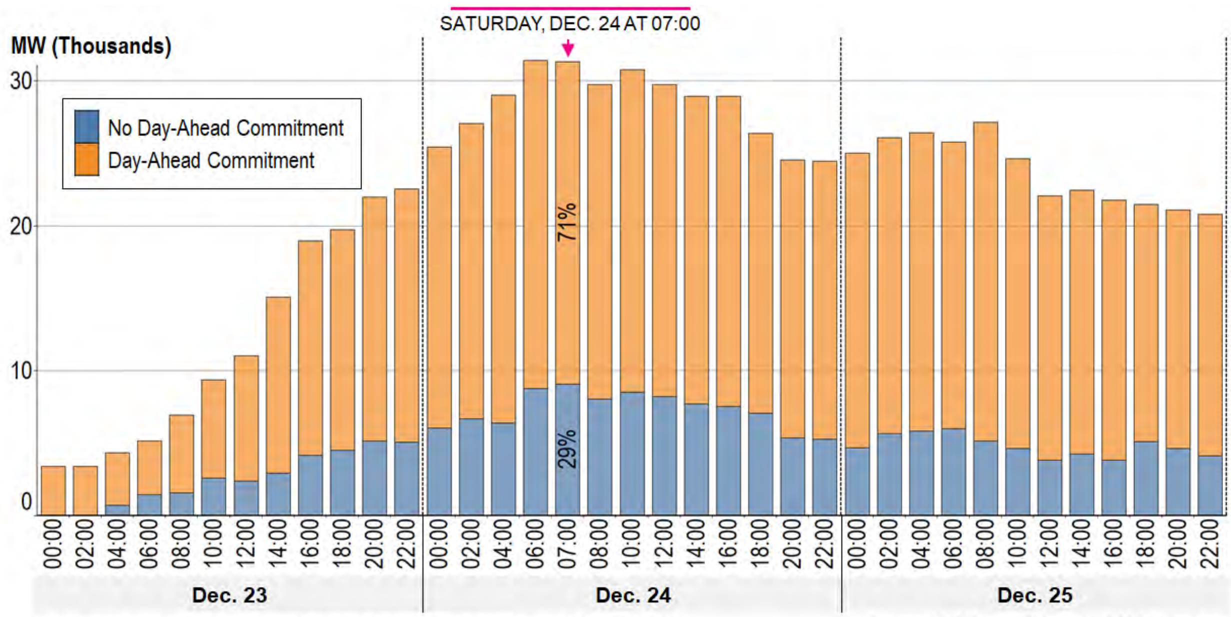
Note: Only even hours are shown for readability with the exception of Dec. 24, 2022, 07:00, which was the hour with the largest amount of forced outages and derates.

Source: GADS as of March 1, 2023. Wind and solar unit outages are not included in the data.

When scheduling replacement energy to account for the missing 16,000 MW, PJM was relying on the unit information submitted by Generation Owners to evaluate the amount of available reserves and the timelines needed to schedule those units if/when needed (15-minute notice, 30-minute notice, one-hour notice, etc.) As noted previously, PJM requires Generation Owners to update their parameters to reflect any changes from normal operating condition so that the reserve calculations are accurate. However, in the case of Winter Storm Elliott, these parameters were not updated for many generators. More specifically, the following information was not updated to align with actual operating conditions including longer notification times, extended minimum run times, inflexibility in dispatch range, etc. This was predominately related to gas-fired generators where pipeline restrictions, nomination deadlines and the unavailability of gas supply were not accurately reflected in generator operating parameters, despite having the ability to utilize Temporary Exceptions or Real-Time Values (PJM Manual 11, Sections 2.3.4.3 and 2.3.4.4) to convey this information accurately to PJM.

For the Dec. 23 operating day, only 6% (37 out of 578) of the gas-fired generators in the PJM system submitted increased notification time requirements. All others were reported as available to operate, with their normal operating parameters in place. This lack of timely and accurate information led to extremely challenging conditions for the PJM system operators that continued through the end of the day on Dec. 25. As presented in Figure 36, the failure of so many Day-Ahead Market committed units, coupled with the lack of generator parameter updates, led to a high volume of natural gas generators having no Day-Ahead Market commitment and then becoming forced outages due to lack of fuel.

Figure 36. Dec. 23, 24 and 25 Forced Outages With and Without Day-Ahead Market Commitment



Note: Only even hours are shown for readability with the exception of Dec. 24, 2022, 07:00, which was the hour with the largest amount of forced outages and derates.

Source: GADS as of March 1, 2023. Wind and solar unit outages are not included in the data.

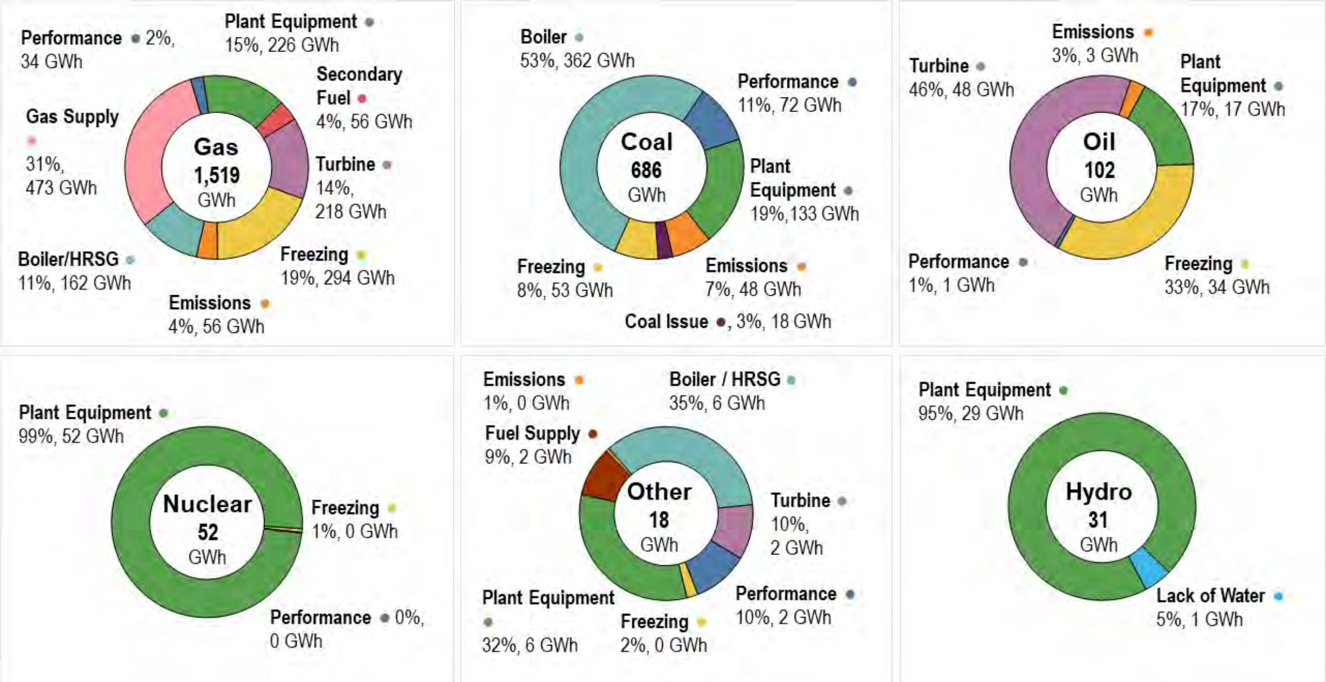
In addition to forced outages, approximately 6,000 MW of steam generation was called but was not online as expected per their time to start for the morning peak on Dec. 24. The vast majority of these resources were gas-fired resources.

The high rates of generator outages also limited PJM's ability to replenish pond levels for pumped storage hydro prior to the morning peak on Dec. 24. That left PJM with extremely limited run hours for pumped storage generation. Between forced outages, derates, generators that did not start on time, and the inability to fill pumped storage hydro ponds, PJM was operating with approximately 47,000 MW of generator unavailability for the Dec. 24 morning peak, including the unavailability of pumped storage resources to generate.

The highest forced outage rate during Winter Storm Elliott was over 24%, which is higher than PJM experienced during the Polar Vortex in 2014. This level of generation outages was unprecedented and not anticipated. PJM, along with the Independent Market Monitor, has undertaken efforts to determine what happened with these generators to understand both why these failures occurred and how to reduce them in the future. This is further discussed later in the report.

To effectively compare resource unavailability by fuel type and by cause during the Winter Storm Elliott event, both the reduction quantity and duration must be considered. While a 1,000 MW forced outage is much larger than a 100 MW forced outage, if the 1,000 MW forced outage only lasts one hour but the 100 MW forced outage lasts one day, then the 100 MW forced outage is a more significant unavailability event. Using MWh as the comparison metric incorporates both the magnitude and duration of the outage to give a more complete picture of the impact. **Figure 37** presents the MWh analysis for a duration of Dec. 23 00:00 to Dec. 25 23:59.

Figure 37. Dec. 23, 24 and 25 Forced MWh by Fuel Type and Cause



In **Figure 38**, total available MWh for the period of Dec. 23 to Dec. 25 was calculated by multiplying GADS Net Dependable Capacity by 72 hours. The MWh outage rates shown in **Figure 38** were then overlaid to show availability by fuel type.

Figure 38. Dec. 23, 24 and 25 Availability by Fuel Type

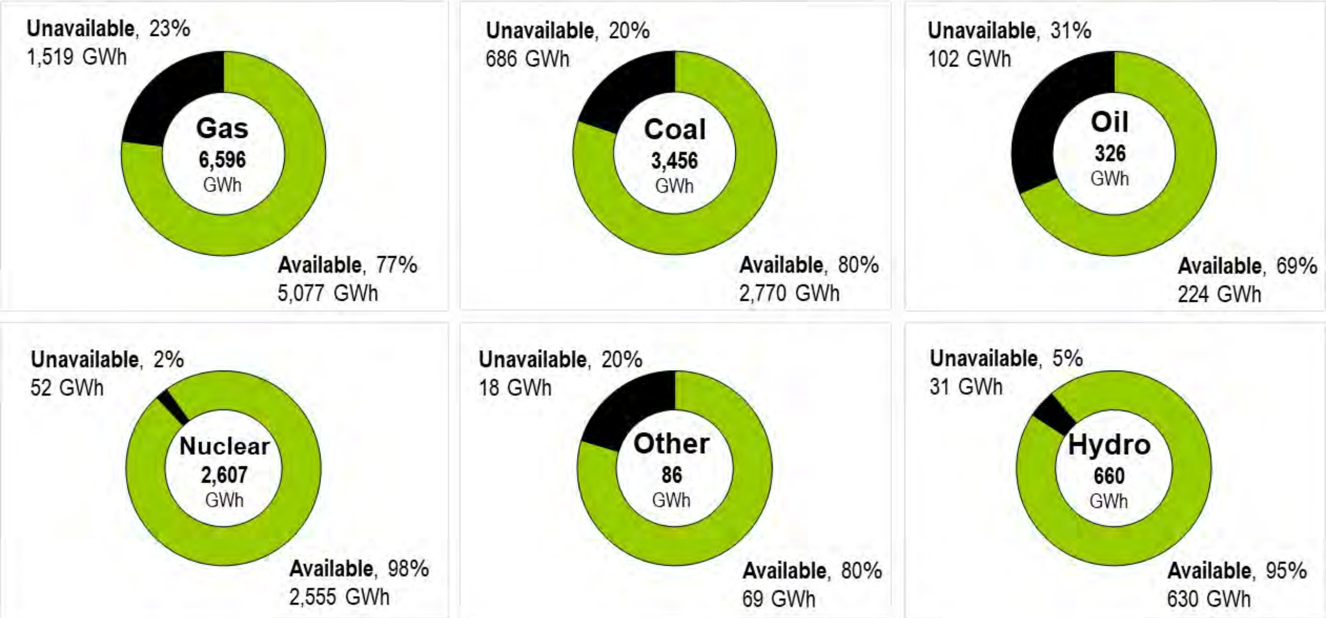
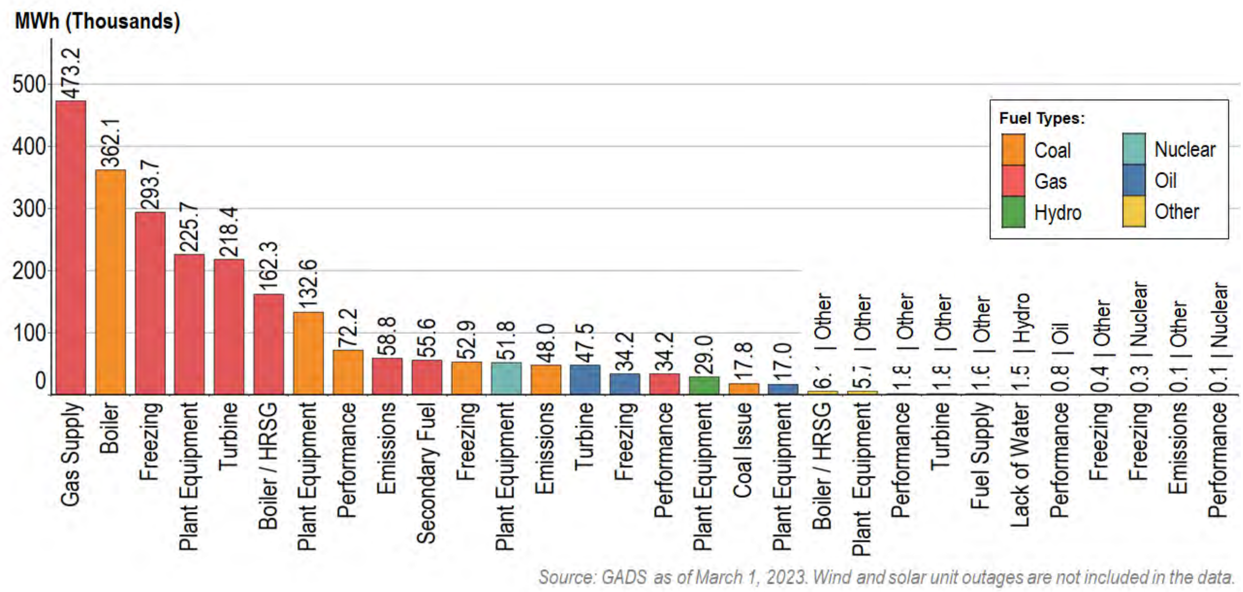


Figure 39 breaks down the outage causes further, considering both fuel type and outage cause. Overall, freezing, plant equipment issues – including boiler, heat recovery steam generator (HRSG) and turbine problems, and emissions make up the majority of outages.

Figure 39. Dec 23, 24 and 25 Forced MWh by Fuel Type and Cause



Generation Cold Weather Operating Limit Analysis

As noted previously, PJM issued a data request in 2022 to capture the Cold Weather Operating Limit (CWOL) for each generating unit. This information indicates the minimum temperature that each unit can reliably operate to. The chart to the left in Figure 40 presents the results of an analysis of the percentage of units that reported in GADs specifically as freeze-related causes for their outages and tripped/failed to start at actual temperatures above or below their reported minimum operating temperature limit. The second chart (in Figure 40) shows a similar analysis, but it uses the effective temperature (i.e., wind chill) instead of the actual temperature. As can be seen, the effective temperature is a better indicator for identifying when generators are at risk of experiencing freeze-related issues. Based on the GADS data, 21,355 MW of generation incurred a forced outage at or above their limit and 18,544 MW experienced a forced outage below their limit.

PJM then expanded this temperature analysis look at specific temperature ranges. The purpose of this analysis was to understand the magnitude of deviations from the reported operating limits. This analysis drilled down to specific temperature ranges where a unit incurred a forced outage at/above or below their CWOL temperature. Note that there is one unit in the 0°F category, indicating that it incurred a forced outage exactly at its CWOL temperature. From the data analyzed, the majority (13,349 MW) of forced outages occurred within 10°F of units' CWOL temperature. Conversely, 17 units (3,113 MW) incurred a forced outage more than 20°F above their CWOL temperature, which may indicate that they either overestimated the capabilities of the unit or did not provide a practical or realistic CWOL temperature to PJM. There were 4,685 MW (five units) that were able to operate 20°F or more below their CWOL temperature.

Figure 40. Cold Weather Operating Limit Comparison Against GADS Reported Outage and Temperature

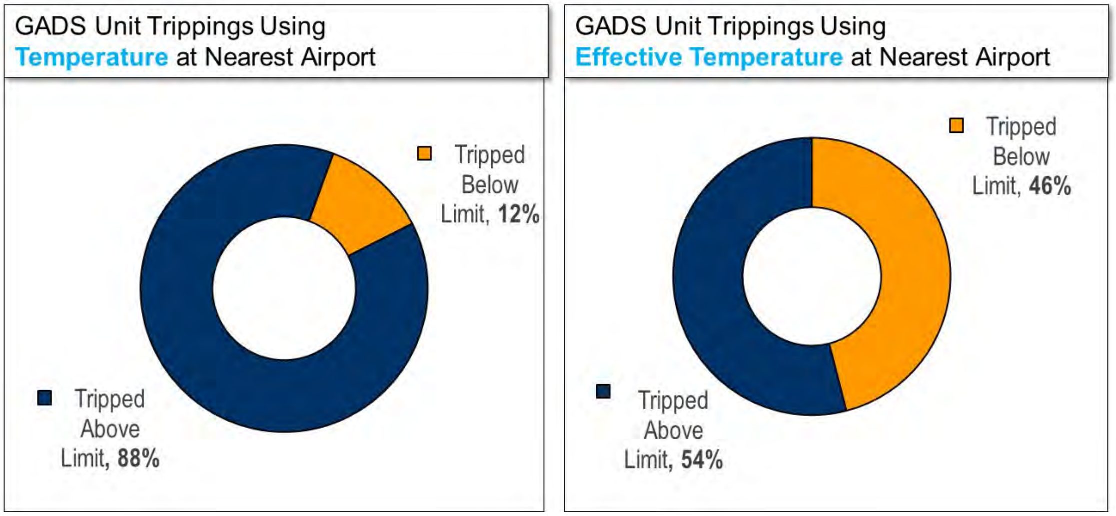
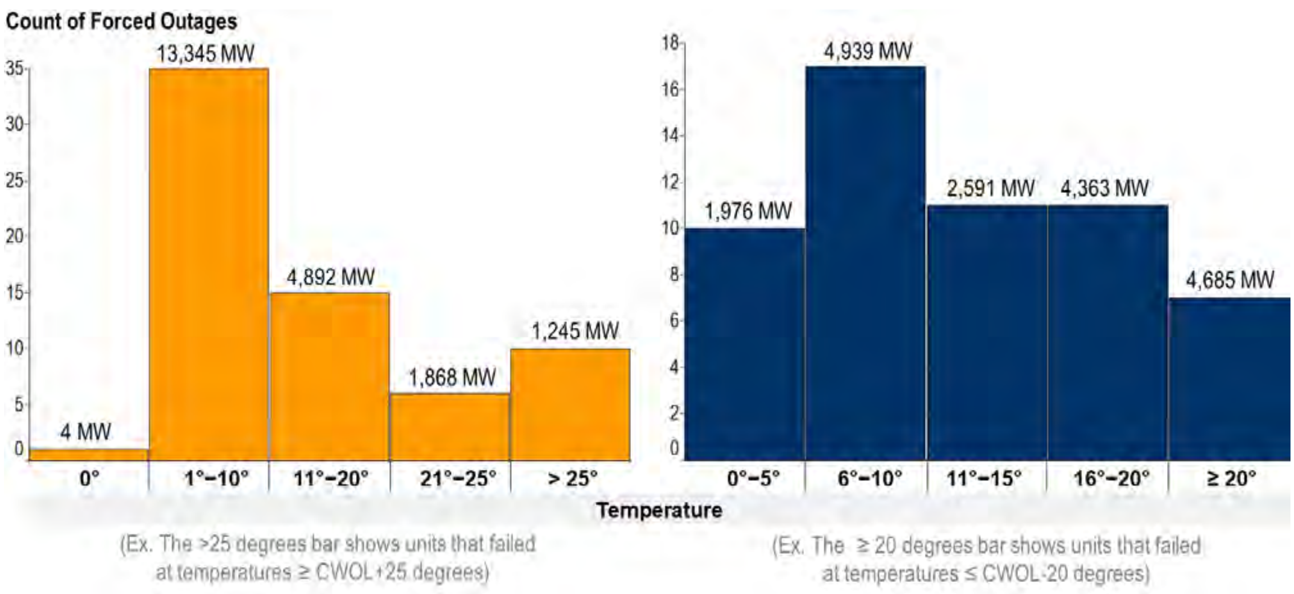


Figure 41 presents a comparison of the effective temperatures experienced by units at the time of a cold weather-related forced outage with their submitted CWOL temperature. The chart to the left presents the MW quantity of the units that failed at different temperatures ranges prior to reaching their CWOL temperature. The chart to the right (presented in blue) presents unit failures below their CWOL temperature.

Figure 41. Temperature Deviations for Weather-Related Forced Outages



Renewable Generation Performance

Figure 42 and Figure 43 represent the performance of both wind and solar resources. Both charts utilize a similar method to represent the maximum potential output, labeled Available ICAP, by taking the total Installed Capacity and subtracting out any generation outages (planned, maintenance and unplanned). The Available UCAP represents the expected performance based upon the capacity value of the Available ICAP. For the 2022/2023 Delivery Year, this value is 13% for wind and 38% for solar.

As shown in Figure 42, wind generation on average performed above its expected capacity. This is not unexpected and something PJM sees on the coldest winter days where the wind speed also increases customer demand due to increased heating needs. However, it should be noted that this does not hold true during the summer where the highest electric demand is coincident with the lack of any wind and its associated cooling effect on air conditioning usage.

Solar, on the other hand, only met or exceeded its capacity expectations during a few hours each afternoon, which was not coincident with the peak electric demand periods. That said, as noted above with wind, it is important to point out that lack of the heating from the sun does coincide with high heating demand in the winter, but the converse is true in the summer. During the peak summer hours, the electric demand is driven by heating from the sun, which is also when solar generation output is at its peak.

Figure 42. Wind Resource Performance

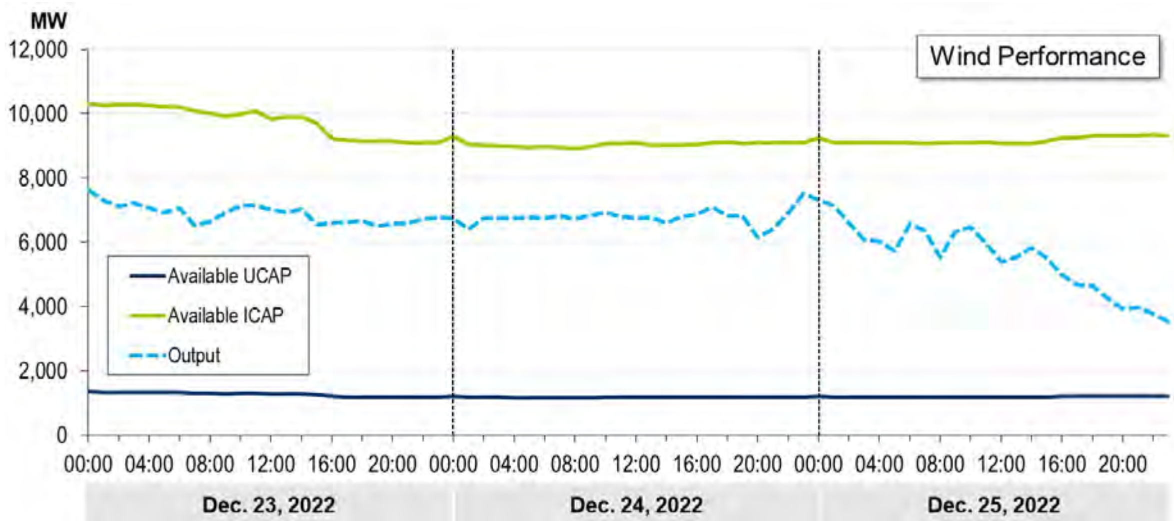
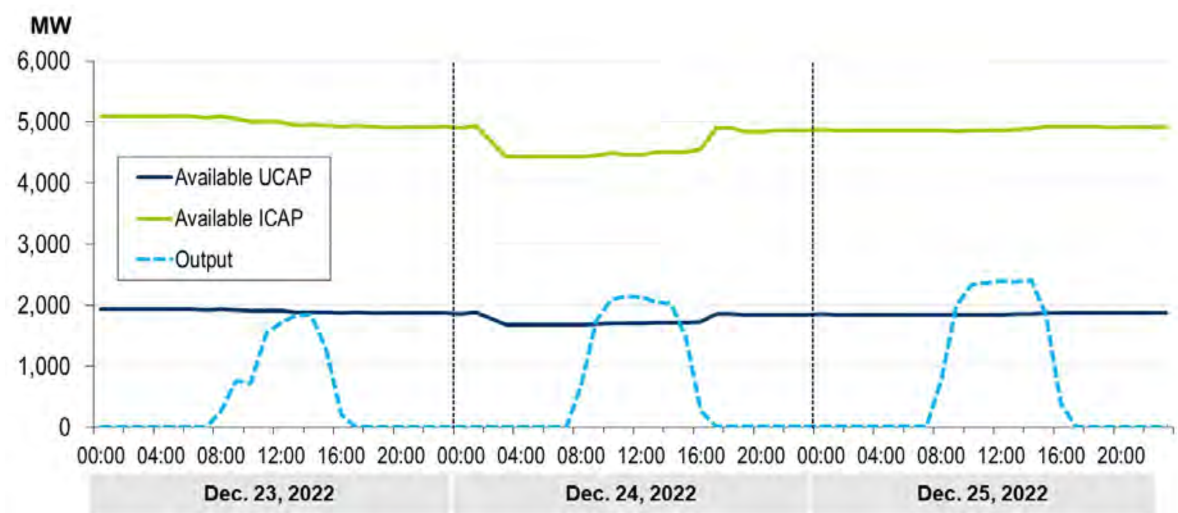


Figure 43. Solar Resource Performance

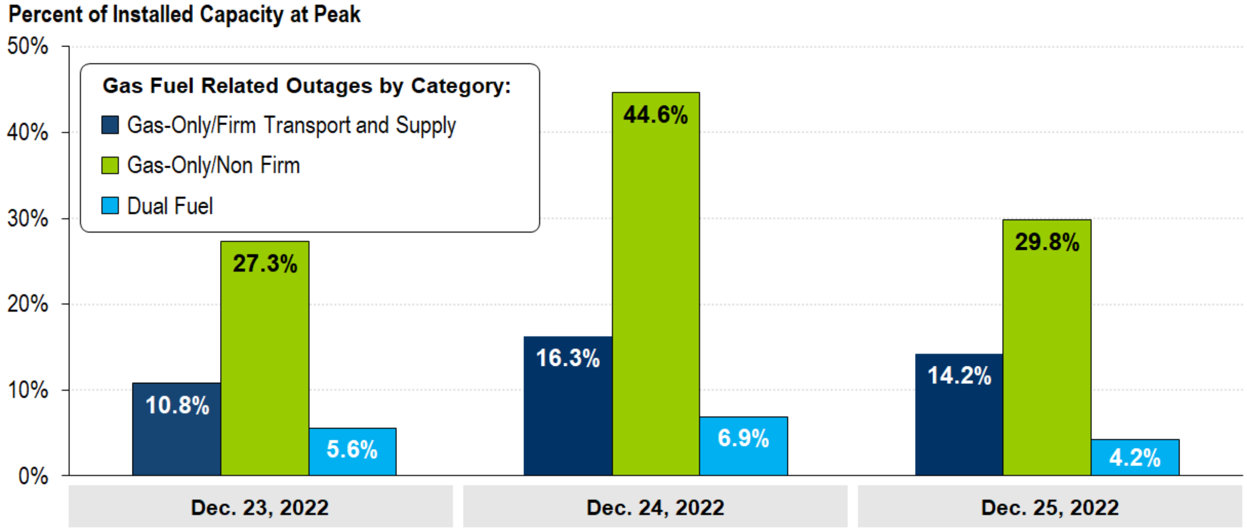


Fuel Security Observations

While PJM has focused on the 24% forced outage rate overall and by fuel type in this report thus far, it is also important to note that 76% of the generation fleet did perform well. In particular, hydro and nuclear had availability rates of 95%

and 98%, respectively, as shown in **Figure 36**. In addition, wind performance was well above the expected output, as shown in **Figure 42**. Furthermore, one of the more stark observations is the difference in the performance of gas units with respect to their level of fuel security. As shown in **Figure 44**, duel-fuel units performed extremely well, with an average forced outage rate of 5.6% with respect to fuel-related outages. Whereas gas units with firm and non-firm fuel supply arrangements experienced forced outage rates of 13.8% and 33.9%, respectively. While this performance data is representative of only the Winter Storm Elliott period, it does highlight the importance of having secure fuel arrangements to minimize the risk of losing access to fuel supply when it is most urgently needed.

Figure 44. Gas Fuel-Related Outages by Category by Percent of Installed Capacity at Peak



Generation Parameter and Outage Reporting Tools

PJM and members use several tools to collect and manage generator outage data, including the following applications:

- **Markets Gateway** – Markets Gateway is a PJM tool that allows members to submit generation schedules, as well as other information and data needed to conduct business in the Day-Ahead, Regulation and Synchronized Reserve Markets.
- **eDART** – eDART (Dispatcher Application and Reporting Tool) is a real-time and forward-looking tool that allows Generation and Transmission Owners to submit generation and transmission outage requests. eDART allows its users to manage their outage data by viewing the status of their outages and obtaining outage reports.
- **eGADS** – The Generator Availability Data System (eGADS) supports the submission and processing of generator outage and performance data as required by PJM and North American Electric Reliability Corporation (NERC) reporting standards. eGADS is an after-the-fact outage reporting tool used to capture more detailed information about generator outages that are submitted several weeks after the outage.

The generation schedules submitted via Markets Gateway are collections of generator parameter operating limits and offer data. There are three types of schedules that can be submitted, as defined in PJM Manual 11, Section 2.3.4:

- **Cost-Based Schedule** – Cost-based schedules must comply with limits placed on certain parameters In addition, generation resource cost-based energy offers must be developed in accordance with Manual 15: Cost Development Guidelines and PJM's governing documents.

- Price-Based Parameter Limited Schedule (PLS) – Price-based PLS schedules must comply with limits placed on certain parameters. Price-based PLS energy offers may be market based.
- Price-Based Schedule (non-PLS) – Non-PLS price-based schedules are not subject to the parameter limits defined in and may submit market-based energy offers.

Market Sellers of capacity resources are required to submit schedules in Markets Gateway, based on whether the unit is price based or cost based:

- For Price-Based Units: At least one cost-based schedule is parameter limited and a price-based PLS.
- For Cost-Based Units: At least one cost-based schedule is parameter limited. Certain parameters on cost-based and price-based PLS schedules are subject to defined limits.

It is important for Market Participants to ensure the generator parameter operating limits and offer data are up to date in Markets Gateway. In the event that PJM declares a Maximum Generation Emergency; issues a Maximum Generation Emergency Alert, Hot Weather Alert or Cold Weather Alert; or schedules resources based on the anticipation of a Maximum Generation Emergency, Maximum Generation Emergency Alert, Hot Weather Alert, or Cold Weather Alert for all or any part of such operating day, generation resources are committed on the more economic schedule between their price-based PLS and price-based schedule.

Generation resources are required to report outages in advance of the operating day (when known) and in real time through the eDART application. This reporting must include the cause of the outage, as indicated in PJM Manual 14D. Furthermore, PJM also requires more detailed after-the-fact reporting of all outages in the GADs system by the 20th of the following month.

Generation Owners may augment previous eDART submissions to reflect additional forced outages, but retroactive eDART changes to remove or reduce previously submitted forced outages are not permitted as noted in PJM Manual 10, Section 2.2.1. If a Market Participant needs to remove or minimize a forced outage status previously submitted in eDART, such a revision must be submitted via eGADS and not eDART. PJM does not validate data on causes of outages. If a unit is out of service, it could be liable for a penalty. The eGADS outage is reported to NERC.

As part of the Cold Weather Alert, PJM requires generators to update their availability and operating parameters (notification time, start time, unit cost, etc.) in the Markets Gateway and eDART tools. In 92% of cases where generators failed to perform, PJM either had little or no notice, and very few resources provided updated parameters to reflect known fuel supply constraints or other unit issues.

Lack of timely reporting to PJM's eDART system during Winter Storm Elliott presented challenges for PJM Operations Planning. Many eDART outage submittals lacked sufficient details or inaccurate information, such as cause codes, requiring manual review and outage cause categorization for post-event analysis. PJM and Monitoring Analytics observed a large discrepancy (between 5,000 to 10,000 MW, varying over the period of the event in unplanned outage totals upon initial review of outage data in eDART and GADs). Monitoring Analytics issued a notice to Generation Owners with the recommendation to review and update or submit outage tickets in eDART and GADs to capture outages accurately for post-event analysis. Nearly 300 new outage tickets totaling more than 21,000 MWs of reductions and over 100 revisions to prior tickets totaling more than 14,000 MW of reductions were submitted after the Winter Storm Elliott event.

In addition to Operations Planning, the outage data has many additional use cases, including several of the charts and figures in this report. Having accurate and near real-time eDART outage information helps PJM understand the nature of the outage and a potential return time to bring the unit back in service. The eGADS data are utilized in the capacity market to determine the availability of a resource in megawatts when clearing. Having updated outage information is expected under normal conditions and even more critical during emergency conditions like Winter Storm Elliott.

Gas Availability Issues

During the morning of Friday, Dec. 23, PJM's Gas-Electric Coordination Team held discussions with many of the interstate gas pipelines serving PJM gas generation to assess system operating conditions. At that point, the cold front had not yet arrived in the eastern part of the PJM system, and, in general, the pipelines in that region were reporting strong operating conditions with high line pack and low-to-moderate demand levels. Meanwhile, the severe cold had already entered the central and Western PJM zones where both gas and electric demand had begun to ramp up quickly corresponding to the rapidly dropping temperatures.

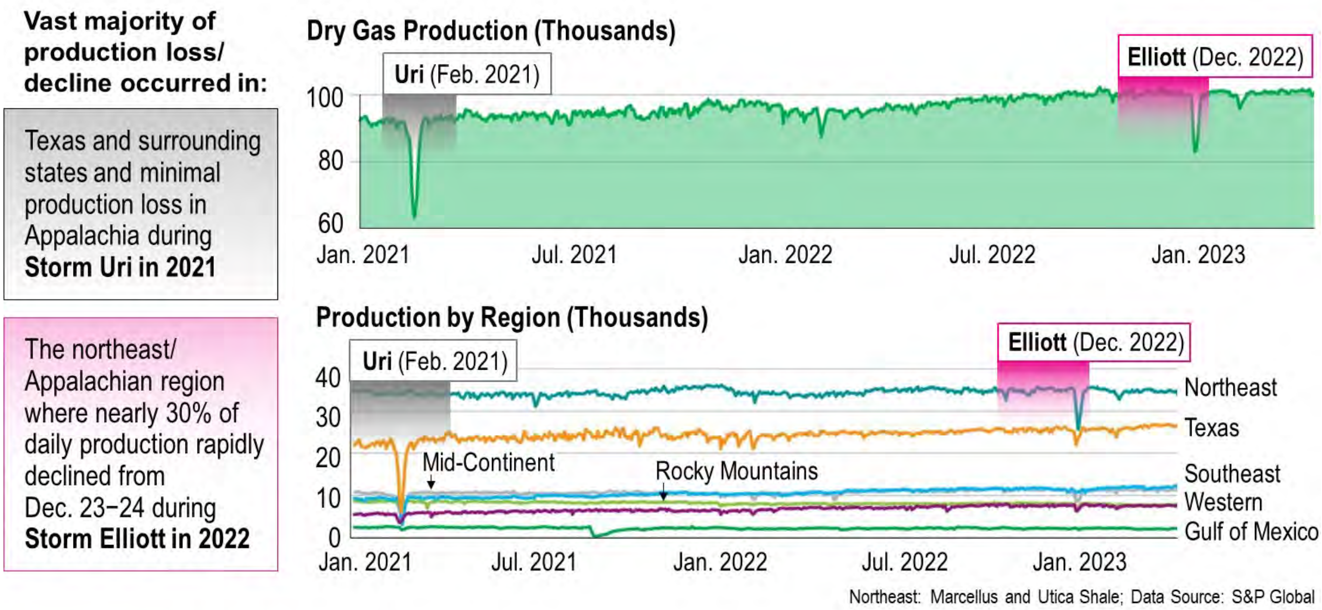
In addition, during this time, several local gas distribution companies (LDCs) began to issue interruption notices for a small number of generators behind their citygates. This is not unexpected during very cold temperatures as LDCs, by nature of their service tariffs, can interrupt gas generation customers in favor of higher priority residential and commercial human needs customers. (Generators served by LDCs make up slightly less than 20% of all gas-fired capacity in the PJM system.) In general, these units are typically smaller combustion turbines with many having dual-fuel capability during the winter months.

The PJM Gas-Electric Coordination Team, as they do each day during the winter months, provided daily gas risk assessment reports to PJM Dispatch to identify which areas of the system may be at higher risk of gas unavailability due to pipeline conditions and restrictions. These assessments also review which units have confirmed gas scheduled on their respective pipelines and compares that to the unit's award commitment to determine if any units haven't scheduled or are short supply. (While gas volumes nominated to generators that are directly connected to interstate pipelines are publically available, nominations to facilities located behind LDC citygates are not and as such not available to PJM. These LDC-served generators represent approximately 20% of the total installed gas generating capacity on the system.) PJM Dispatch uses this information in conjunction with the operating limitations information that the units are providing in eDART and Markets Gateway to have a better understanding of unit availability and which portions of the system are at greater risk of pipeline capacity and gas supply constraints.

While interactions with the pipelines and LDCs are mainly focused on the transportation of natural gas, the supply of natural gas is equally as critical in maintaining reliable fuel deliverability. Natural gas production and midstream facilities, particularly at the wellhead, are subject to freeze-offs during very cold conditions. During Winter Storm Uri in February 2021, there was an extremely large drop in daily gas production due to well freeze-offs in Texas and surrounding states, while very little freeze-off activity occurred in the northeast/Appalachian shale region where most of the gas consumed in PJM originates.

Figure 45 compares natural gas production declines between Uri and Elliott.

Figure 45. Natural Gas Production Declines – Uri Versus Elliott



While there was very little direct impact on PJM during Uri, PJM did reach out to various gas suppliers after Uri to better understand the risk of well freeze-offs and the winterization procedures utilized to mitigate supply loss during cold snaps. The consensus in feedback indicated that natural gas production infrastructure in the northeast was much more hardened and significantly better suited to withstand low temperatures compared to production and processing infrastructure in the south and southwest. Taking that information into consideration and examining past well freeze-offs that actually occurred in the Appalachian region, the best estimate of gas supply loss was around two to three billion cubic feet per day for a one-to-three-day period, which represents approximately 5% to 8% of total northeast daily production. This would not have been unprecedented as it was experienced in prior winter cold snaps, some with temperatures even colder than Elliott. In the end, what ended up occurring was a daily Appalachian gas production loss of 10 to 11 billion cubic feet or approximately 30% of total northeast daily production.

The storm and the rapid onset of cold temperatures heavily impacted natural gas production, particularly in the Marcellus and Utica basins, which are the predominant source of the natural gas procured by gas generation in the PJM footprint. This led to significant loss of gas supply for all downstream gas consumers, particularly larger, more efficient gas-fired power generation units that require nominated supplies flowing at uniform and higher pipeline pressures to operate.

- Supplies from the Appalachian Basin shrank 27% from usual levels, according to reports by Bloomberg.
- Well freeze-offs sent production plunging by more than 20% in Pennsylvania, while output more than halved in Ohio, constraining supplies into the Northeast and the Tennessee Valley.
- There were also losses of pipeline compression that occurred in Ohio and Pennsylvania, which tended to exacerbate gas delivery issues.

Exacerbating the lack of gas supply was the fact that Elliott occurred over a long holiday weekend, which tends to have lower gas supply liquidity. Many gas buyers, especially LDCs and other customers with more predictable gas usage levels, purchase their gas supplies on Friday for the Saturday, Sunday and Monday gas days. Gas generators in many cases need to buy their gas supply each day of the weekend period based on their awarded or anticipated dispatch. With the majority of gas traded on Friday, the market for gas commodity can become less liquid, resulting in increased supply scarcity and potentially higher intraday gas prices.

Risk of Load Shed

PJM was faced with an unprecedented amount of unplanned generation outages during Winter Storm Elliott. Operations were critical on the evening of Dec. 23 and the morning of Dec. 24. Roughly 47,000 MW of generation was unavailable during the morning hours of Dec. 24. PJM was at an increased risk of load shed approaching the morning peak on Dec. 24. If another large unit was lost or imports from NYISO into PJM were cut, PJM would have considered initiating a Voltage Reduction Action, which would have resulted in approximately 1,700 MW of relief, as captured in PJM Manual 13, Section 2.3 on the Voltage Reduction Summary Table. If necessary, this action would have been followed by a Manual Load Dump Warning to communicate load dump allocations to Transmission Owners, and then a Manual Load Dump Action would be implemented if needed, followed by with the issuance of an EEA-3.

The Voltage Reduction Summary table in PJM Manual 13 should be reviewed with PJM Transmission Owners to confirm current capabilities given the changing composition of load.

Non-Retail Behind-the-Meter Generation (NRBTMG) Performance

The Maximum Generation Emergency Actions issued on Dec. 23 and Dec. 24 triggered the requirement for PJM members to load non-retail behind-the-meter generation[9] (NRBTMG). Although PJM system operators do not directly dispatch NRBTMG units, once a Maximum Generation Emergency Action or Deploy All Resource Action emergency procedure is declared in an area, NRBTMG units located in the area are requested to operate at the unit's maximum net or gross electrical power output, subject to the equipment stress limits for the unit.

Winter Storm Elliott was the first time that PJM evaluated NRBTMG units for emergency event performance. There were 339 NRBTMG units in the RTO that were expected to operate and provide 1,316.1 MW of generation during Winter Storm Elliott. The overall performance of the NRBTMG units in the RTO was also well below expected levels, with NRBTMG unit performance shortfalls totaling 888.8 MW and 635.3 MW for the Dec. 23 and Dec. 24 emergency events, respectively. For both events, the percent performance (i.e., average output during emergency event divided by expected performance) for both the Dec. 23 and Dec. 24 events was less than 50%.

Municipal electric systems, electric cooperatives, and electric distribution companies are permitted to use operating NRBTMG to net against their wholesale load. As a result, the load associated with NRBTMG is not required to carry reserves equal to the target installed reserve margin of 14.9% for the 2022/2023 Delivery Year. NRBTMG units that fail to operate during maximum generation emergency conditions can place an additional strain on the PJM system to provide generation to cover the load that NRBTMG typically serves.

Scheduled outages (full or partial) of NRBTMG units are reported to PJM through the Capacity Exchange tool. PJM does not review or approve NRBTMG scheduled outages. Only scheduled outages during the period of October through May and reported to PJM in advance of an emergency event can be used to excuse the unit for failing to perform as expected and eliminate or reduce their performance shortfall. Excusals for scheduled outages reported in advance of the Dec. 23 and Dec. 24 emergency events were granted to a number of units.

[9] Non-retail behind-the-meter generation (NRBTMG) is behind-the-meter generation that is used by municipal electric systems, electric cooperatives and electric distribution companies to serve load in a wholesale area. A NRBTMG unit delivers energy to a wholesale area's load without using the transmission system.

Failure of NBTMG units in a wholesale area to perform as expected during Winter Storm Elliott does not result in explicit financial penalties to be assessed in a member's PJM bill; however, failure to perform results in implicit penalties to the wholesale area through increased transmission charges for 2024 calendar year and capacity charges for the 2024/2025 Delivery Year. For NRBTMG units in a wholesale area that fail to perform, a netting reduction penalty amount for an emergency event is calculated as 10% of the net unit performance shortfalls in the wholesale area.

A netting reduction penalty amount will reduce the amount of the operating NRBTMG that is allowed to net against the wholesale area load during coincident peak hours during the Nov. 1, 2022, through Oct. 31, 2023, period and result in an upward adjustment to the wholesale area's network service peak load for the 2024 calendar year and obligation peak load value for the 2024/2025 Delivery Year. The total netting reduction penalty amount for the RTO as a result of Winter Storm Elliott was 153.8 MW (89.4 MW for Dec. 23 and 64.4 MW for Dec. 24).

Table 2 summarizes the NRBTMG performance results for the RTO.

Table 2. Dec. 23 and Dec. 24 NRBTMG Performance Results

	Dec. 23, 2022	Dec. 24, 2022
Expected Performance (MW)	1,316.1 MW	1316.1 MW
Unit Performance Shortfalls (MW)	888.8 MW	635.3 MW
Netting Reduction Penalty Amount (MW)	89.4 MW	64.4 MW

Market Outcomes

The Market Outcomes section of the report presents both the Day-Ahead and Real-Time market results for Dec. 23 and Dec. 24, including the ancillary services markets. This section also presents the analysis of Performance Assessment events. Appendix A presents market operations background information.

Day-Ahead Market Results

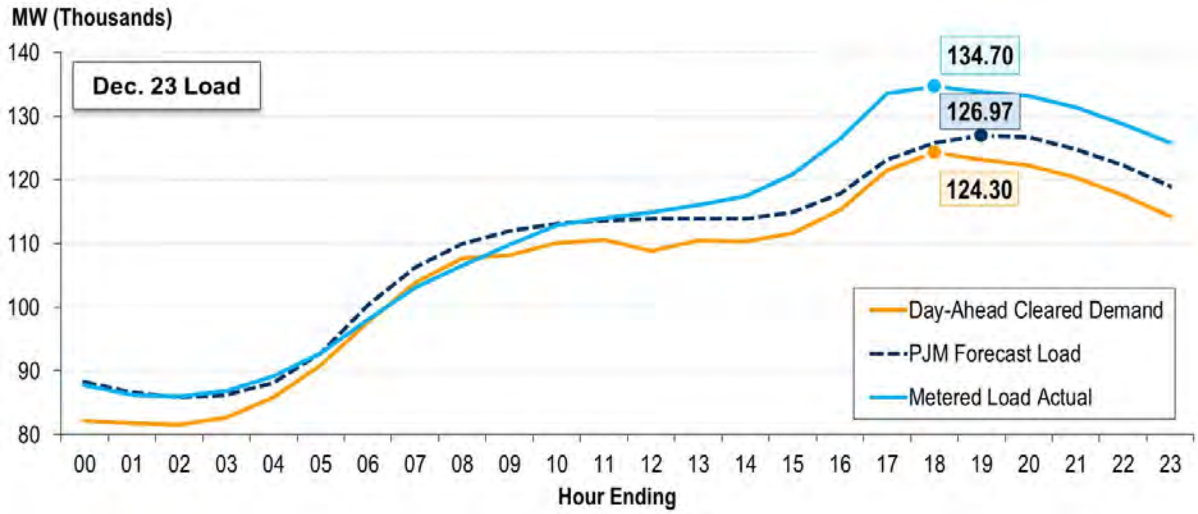
The Day-Ahead Energy Market is a forward market in which hourly clearing prices are calculated for each hour of the next operating day, based on generation offers, demand bids, increment offers, decrement bids, up-to-congestion bids and bilateral transaction schedules submitted into the Day-Ahead Energy Market. Additionally, the Day-Ahead Energy Market also incorporates reliability commitments by PJM system operators and reserve requirements into the analysis. Day-Ahead Energy Market enables participants to purchase and sell energy at binding Day-Ahead LMPs.

The resulting day-ahead hourly schedules, generated by the dispatch run, and Day-Ahead LMPs, generated by the pricing run, represent binding financial commitments to the Market Participants. The Day-Ahead Market settlement is calculated for each Day-Ahead Settlement Interval (currently hourly) based on scheduled hourly quantities resulting from the dispatch run and on Day-Ahead hourly prices resulting from the pricing run.

Day-Ahead Load and Prices

Figure 46 presents the cleared bid demand, including decrement bids and up-to-congestion bids.

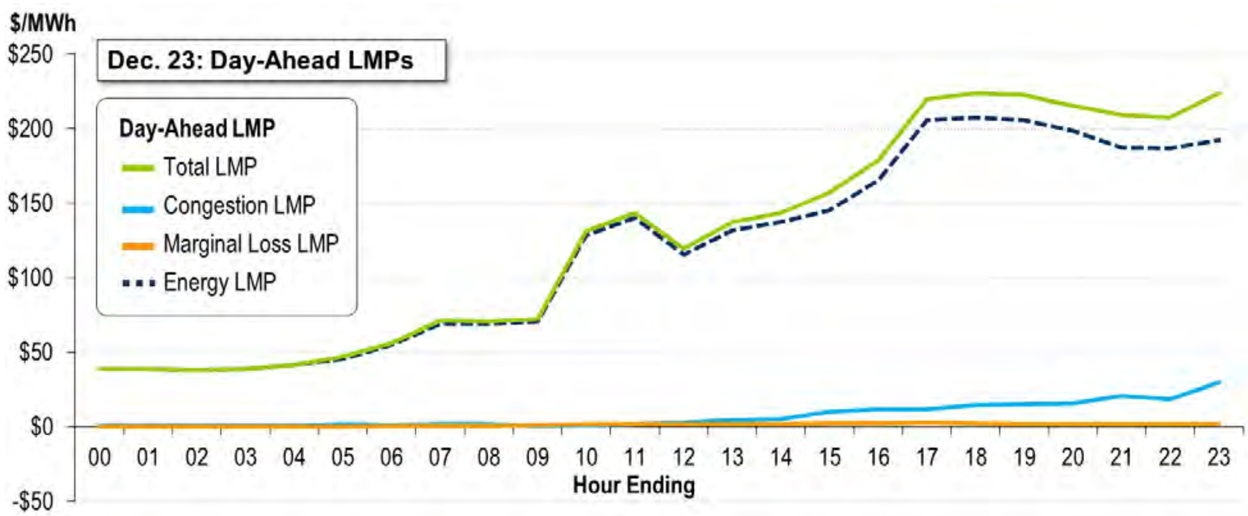
Figure 46. Dec. 23 Day-Ahead Cleared Demand, Forecast Load and Metered Load



For Dec. 23, the day-ahead demand cleared at approximately 124,300 MW, while the actual metered load, including the deployment of Demand Response, came in at approximately 134,700 MW, resulting in a net of approximately 10,400 MW more load in real time than was captured in the Day-Ahead Market cleared demand. PJM's original forecast on Dec. 22 at 18:00 was approximately 126,700 MW, which was about 7,700 MW under the actual load, less Demand Response.

Figure 47 presents the Day-Ahead LMPs for Dec. 23.

Figure 47. Dec. 23 Day-Ahead LMPs

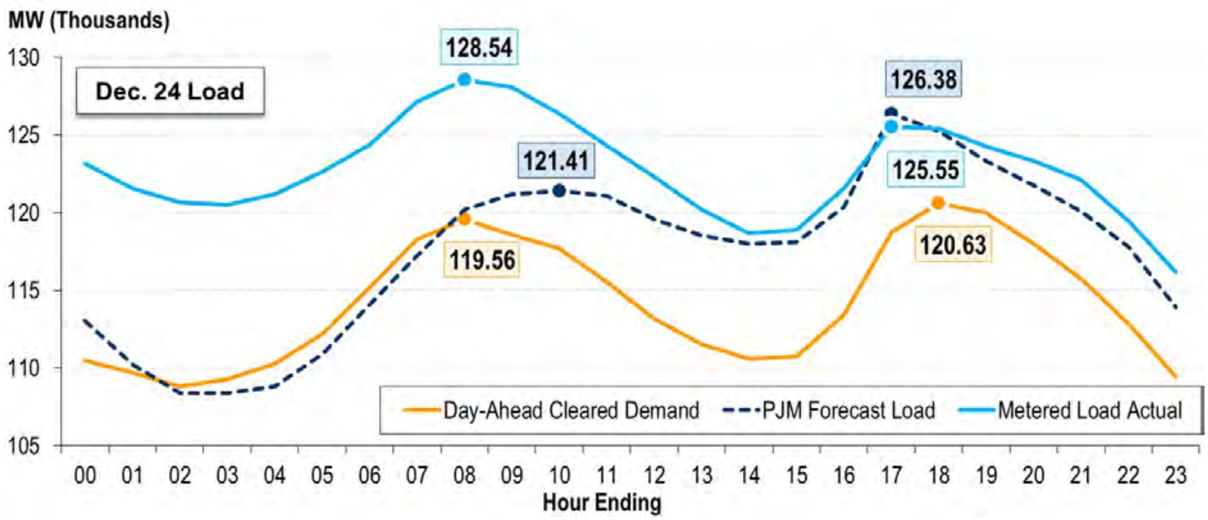


The Day-Ahead LMPs for Dec. 23 were higher than a typical Day-Ahead price, with a peak hourly LMP of $224/MWh. For example, the monthly load-weighted LMP for December 2022 was $93.39/MWh[10]. In the Day-Ahead Market, energy shortage conditions did not occur. LMPs increased in the Day-Ahead Market through the day based on the increasing load levels shown in Figure 47.

[10] Market Monitor Report presentation by Monitoring Analytics. PJM Members Committee Webinar, May 22, 2023.

Figure 48 presents the cleared bid demand, including decrement bids and up-to-congestion bids, and the resulting Day-Ahead prices for Dec. 24.

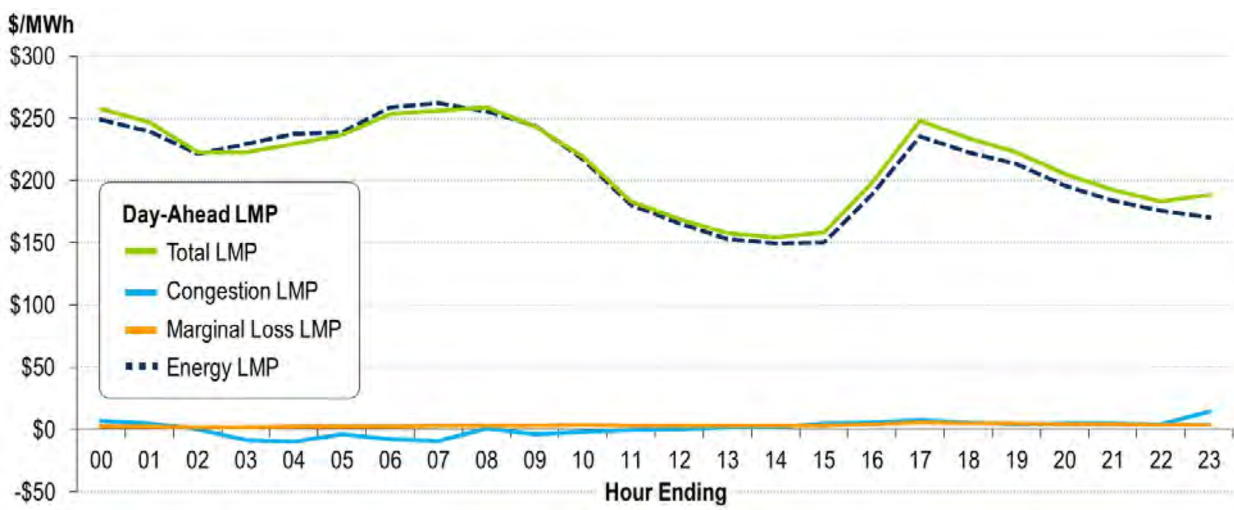
Figure 48. Dec. 24 Day-Ahead Cleared Demand, Forecast Load and Metered Load



On Dec. 24, the day-ahead cleared demand was less than real-time load by approximately 9,000 MW over the morning peak and 4,900 MW over the evening peak.

Figure 49 presents the Day-Ahead LMPs for Dec. 24.

Figure 49. Dec. 24 Day-Ahead LMPs



The Day-Ahead LMPs for Dec. 24 were higher than a typical Day-Ahead price, as noted above, with a peak hourly LMP of $259/MWh. In the Day-Ahead Market, energy shortage conditions did not occur on Dec. 24 either.

Table 3 summarizes the units that were offer-capped in the Day-Ahead Market for the Dec. 23 and Dec. 24 operating days.

Table 3. Dec. 23 & 24 Day-Ahead Offer-Capped Unit Summary

	# of Units	Total MW	Non-Liquid Fuel (MW)	
Dec. 23	32	4,428.1	1,495.5	33.8%
Dec. 24	44	6,444.8	34	0.5%

Virtual Transactions

As described earlier, in the Day-Ahead Market, participants may submit various virtual transactions to hedge risk, mirror physical commitments, or account for their expectations of market conditions. The following three types of virtual transactions are available in the Day-Ahead Market:

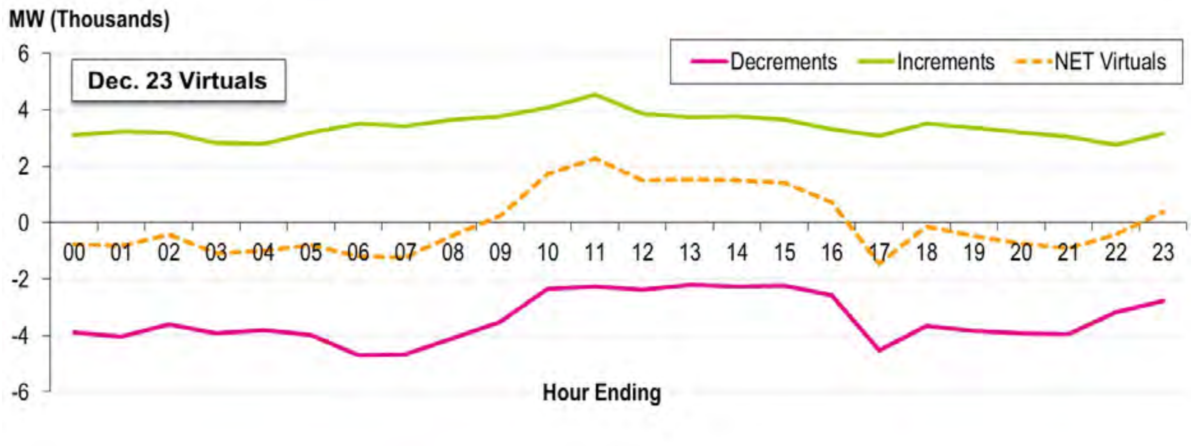
- Increment Offers (INCs) – INCs are submitted in the Day-Ahead Market to sell an amount of energy at a specific location (node) if the Day-Ahead clearing price for that node equals or exceeds the offer price. INCs can be thought of as virtual transactions that emulate generation offers in the Day-Ahead Market. INC transactions are paid the day-ahead LMP for their cleared quantity but must buy out of their position at the real-time LMP. INCs are profitable when the day-ahead LMP is higher than the real-time LMP.

- Decrement Bids (DECs) – DECs are submitted into the Day-Ahead Market as a bid to purchase energy at or below a specified price. DECs can be thought of as virtual transactions that emulate load buy bids in the Day-Ahead Market. DEC transactions pay day-ahead LMP for their cleared quantity and are paid the real-time LMP for the same quantity. Consequently, DECs are profitable when the real-time LMP is greater than the day-ahead LMP.

- Up-to-Congestion Bids (UTCs) – UTCs are bid in the Day-Ahead Market to purchase congestion and losses between two points. UTC bids can be based on the prevailing flow direction where the UTC is buying a position on the Day-Ahead Market congestion, or they can be in the counter-flow direction where they are paid to take a position. The UTC bid consists of a specified source and sink location and a "bid spread" that identifies how much the Market Participant is willing to pay for a congestion-and-loss position between the source and the sink. If the congestion associated with a prevailing flow UTC is less in day-ahead than in real-time, the UTC will be profitable. The opposite is true for counterflow UTCs.

Figure 50 presents the cleared virtual transactions in megawatts, both decrement bids and the increment offers, for the Dec. 23 Day-Ahead Market.

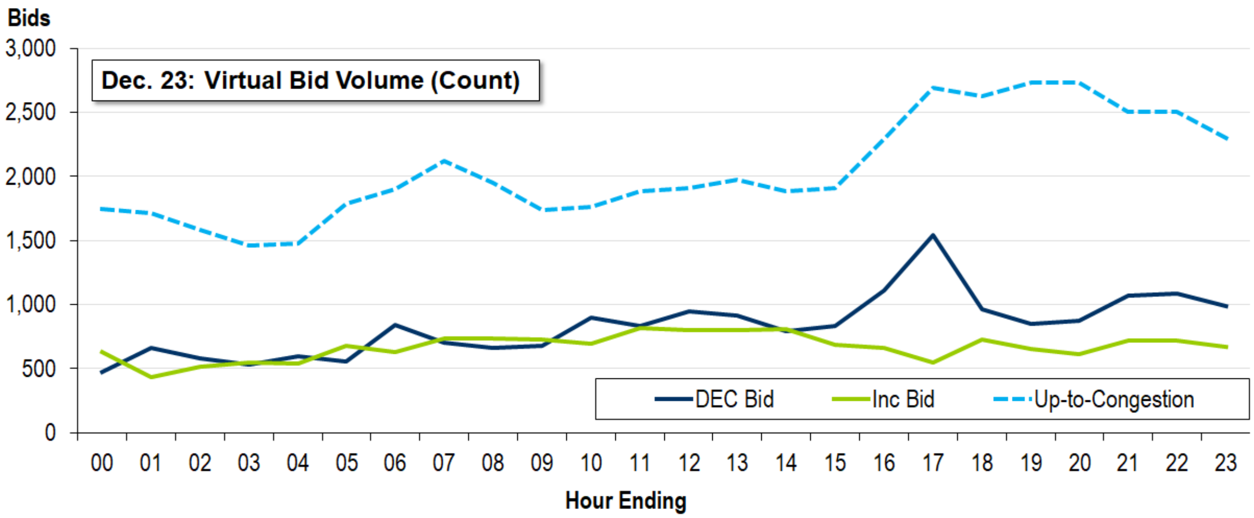
Figure 50. Dec. 23 Cleared Virtual Transactions



As shown in Figure 50, beginning in hour 11 there was approximately 2,000 MW of net virtual generation in the day-ahead solution between hours ending 10:00 and 15:00. Decrement bids in the Day-Ahead Market ranged between 2,200 MW and 4,500 MW and increment offers were between 3,000 MW and 4,500 MW.

Figure 51 presents the virtual transaction volume for Dec. 23.

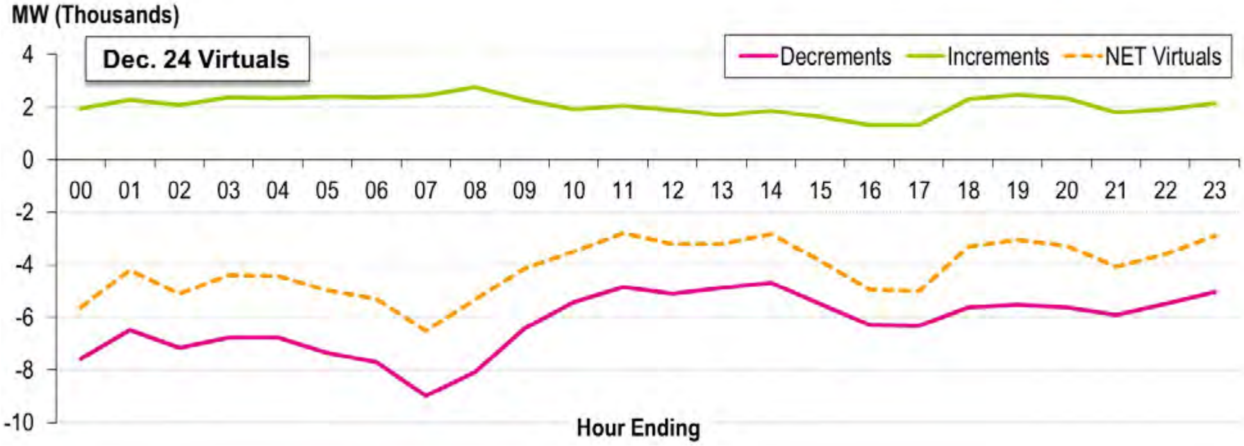
Figure 51. Dec. 23 Virtual Transaction Bid Volume



In the Day-Ahead Market for Dec. 23, there were a maximum of 1,500 individual DEC bids at 15:00 and 814 individual INCs at 11:00.

Figure 52 presents the cleared virtual transactions in megawatts for the Dec. 24 Day-Ahead Market.

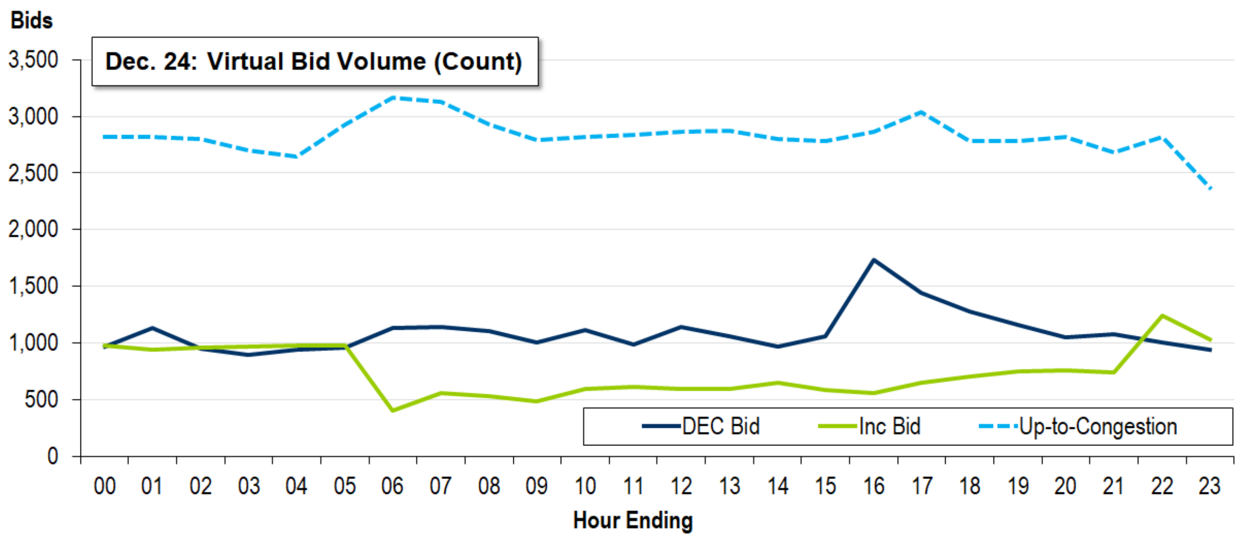
Figure 52. Dec. 24 Cleared Virtual Transactions



As shown in Figure 52, beginning in hour 07:00 there was approximately 6,500 MW of net virtual load in the day-ahead solution. Decrement bids in the Day-Ahead Market totaled approximately 9,000 MW in hour beginning 07:00 and increment bids totaled approximately 2,500 MW beginning in hour 07:00.

Figure 53 presents the virtual transaction volume for Dec. 24.

Figure 53. Dec. 24 Virtual Transaction Bid Volume



In the Day-Ahead Market for Dec. 24, there were a maximum of 1,736 individual DECs at 16:00 and 1,239 individual INCs at 22:00.

In general, demand has been underbid in the Day-Ahead Market on a consistent basis for many years. This is likely in-part due to the desire to purchase some energy on behalf of load at the real-time LMP which can be lower than the day-ahead LMP. This approach carried over to Dec. 23 and Dec. 24, leaving some LSEs exposed to Real-Time Market prices. This could be due to hedging strategies or may be due to uncertainty in load forecasting associated with the expected weather and the holiday weekend. Generators were also exposed to Real-Time Market prices when they were committed in the Day-Ahead Market and were short on their day-ahead commitment in real-time. This can occur when a unit committed in the Day-Ahead Market experiences a forced outage in real-time.

Day-Ahead Reserves

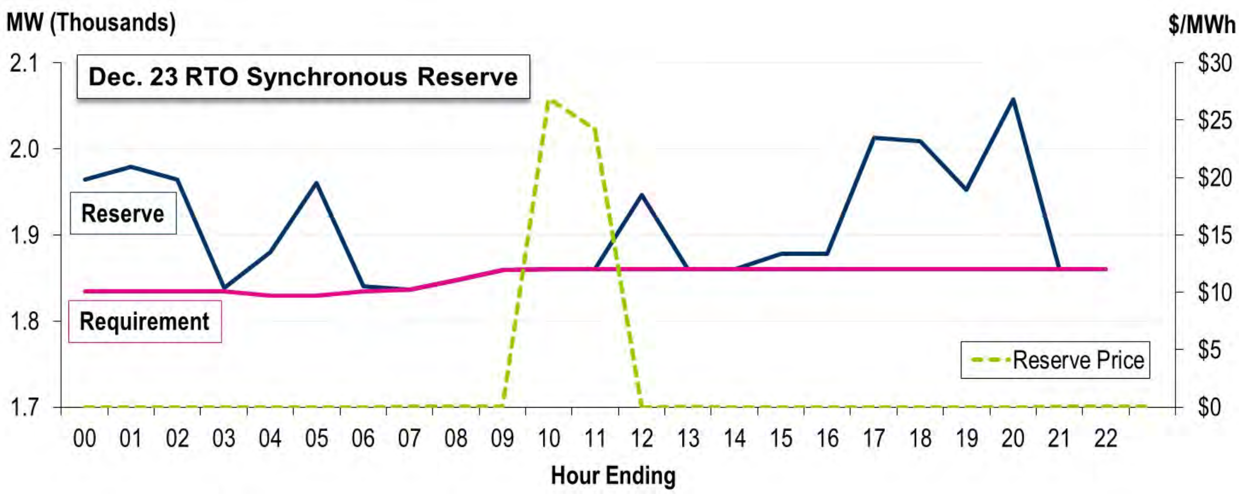
PJM procures resources to meet its reserve requirements, as described earlier in this section, in the Day-Ahead Markets. The clearing of the Day-Ahead Reserve Market results in an hourly price for Synchronized Reserves, Non-Synchronized Reserves and Secondary Reserves for the next day. These prices are posted along with the resource-specific reserve assignments from the dispatch run by 13:30 each day via the PJM Markets Gateway System. The hourly reserve product clearing prices are based upon the offer prices submitted by the committed resources and lost opportunity costs from the pricing run in the Day-Ahead Market clearing software. Lost opportunity cost captures the lost revenues in the Day-Ahead Energy Market a resource may incur by not generating energy but making itself available to provide reserves. For the Dec. 23 and Dec. 24 Day-Ahead Markets, PJM met or exceeded the reserve requirements in all hours.

Offer prices in the PJM reserve markets are limited to the expected value of the non-performance penalty for failing to provide reserves if deployed in real-time. The highest value of the penalty rate was for the month of February 2023, where it was $0.14/MWh.

The reserve markets in the Day-Ahead and Real-Time are modeled such that the highest quality product always has the highest clearing price. For example, the Synchronized Reserve Market Clearing Price (SRMCP) will always be greater than or equal to the Non-Synchronized Reserve Market Clearing Price (NSRMCP) in the same location, because Synchronized Reserve is a higher-quality product than Non-Synchronized Reserve and may be substituted for it. Similarly, the NSRMCP will always be greater than or equal to the Secondary Reserve Market Clearing Price (SecRMCP) in the same location because Non-Synchronized Reserve is a higher quality product than Secondary Reserves and may be substituted for it.

Figure 54 presents the Day-Ahead Synchronized Reserve and prices for Dec. 23.

Figure 54. Dec. 23 Day-Ahead Primary Reserve



PJM met the reserve requirement in the Dec. 23 Day-Ahead Market at zero price, except for the two hours shown in Figure 54. The elevated clearing price for Synchronous Reserves was a result of resources that were backed down to meet the Synchronous Reserve requirement, resulting in non-zero cleared price.

Figure 55 and Figure 56 present Dec. 23 Day-Ahead Primary Reserve and 30-Minute Reserve and prices, respectively.

Figure 55. Dec. 23 30-Minute Reserve and Prices

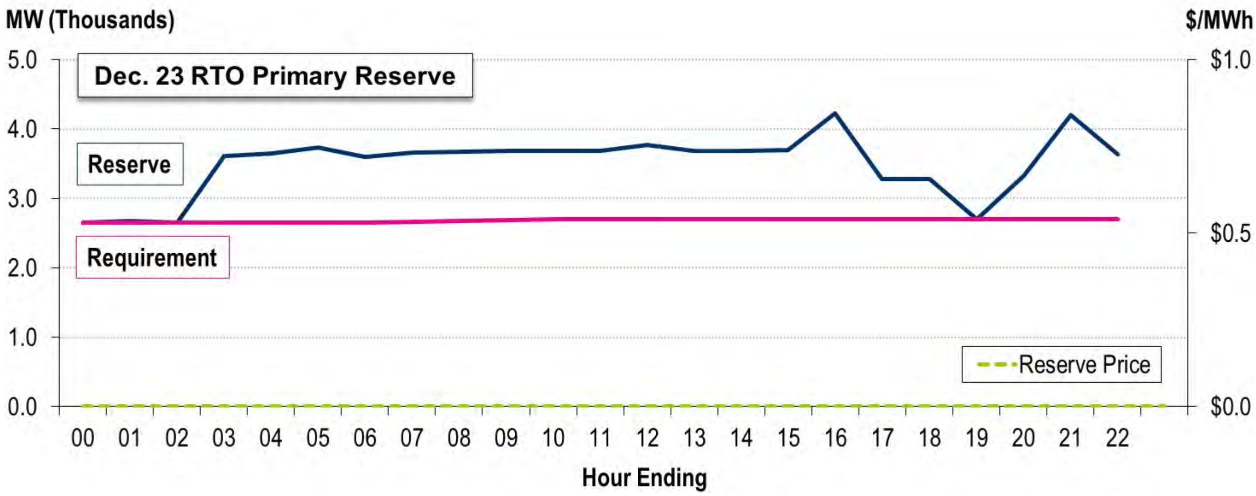
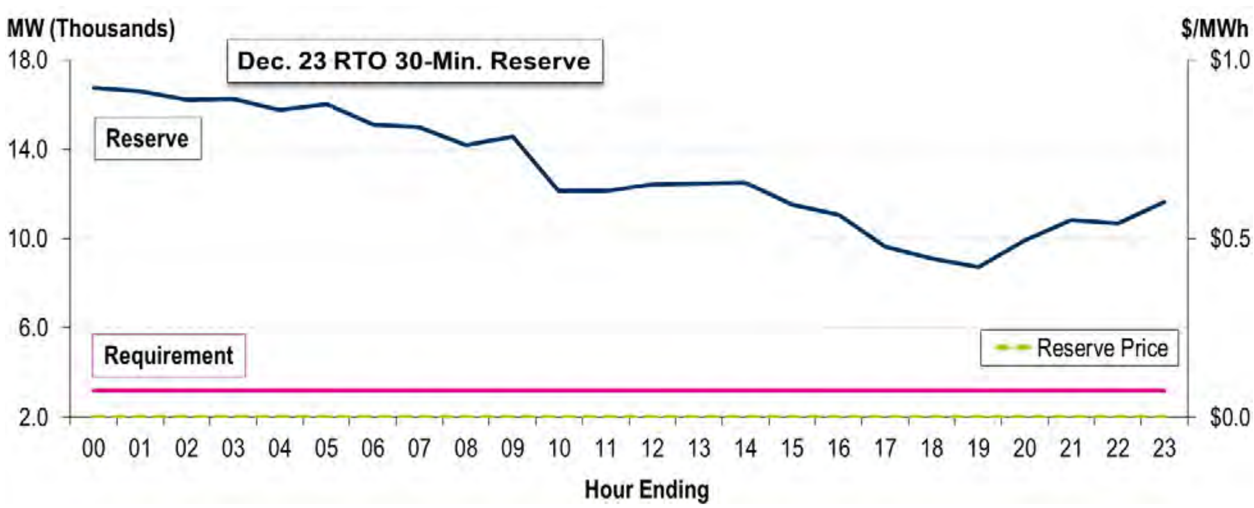


Figure 56. Dec. 23 30-Minute Reserve and Prices



Dec. 23's Day-Ahead Primary Reserve and 30-Minute Reserve prices were zero for all hours, signaling that there were sufficient resources with offers indicating they could meet the requirements to provide those reserves with no adjustment to their schedules in the Day-Ahead Market.

Figure 57, Figure 58 and Figure 59 present the Dec. 24 Day-Ahead Synchronized Reserve, Primary Reserve and 30-Minute Reserve and prices, respectively.

Figure 57. Dec. 24 Day-Ahead Synchronized Reserve

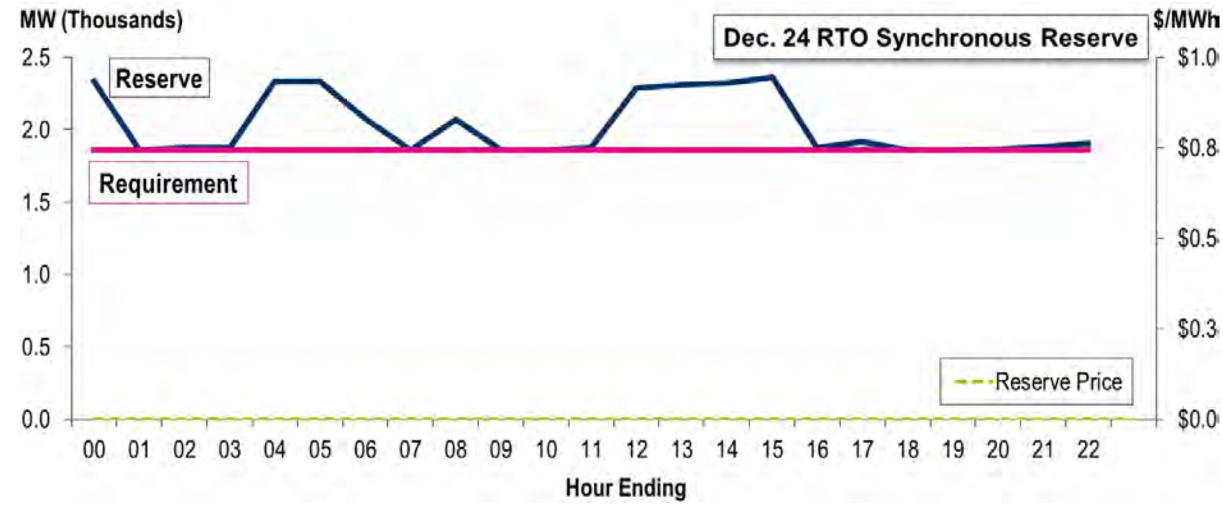


Figure 58. Dec. 24 Day-Ahead Primary Reserve

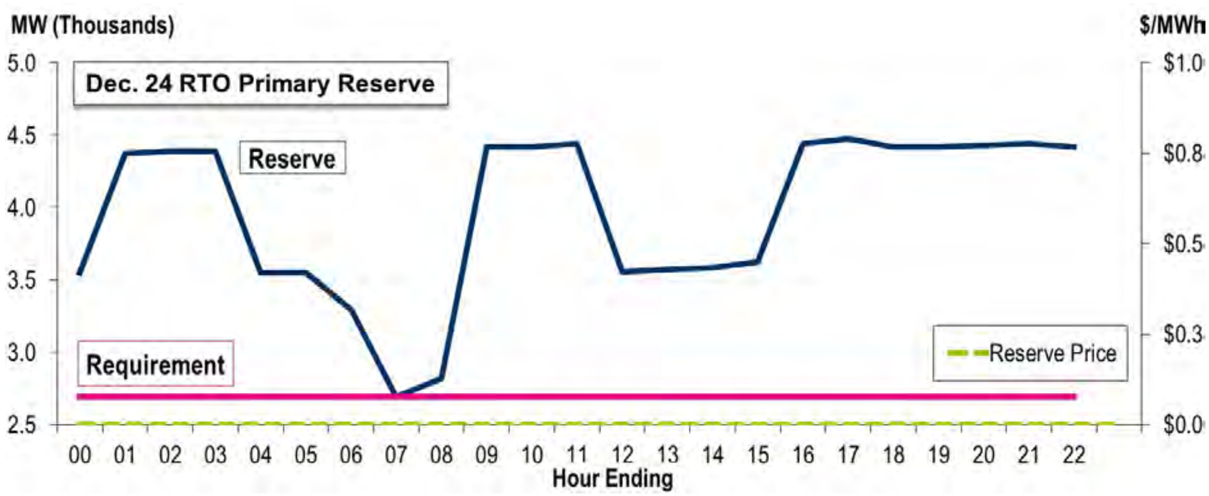
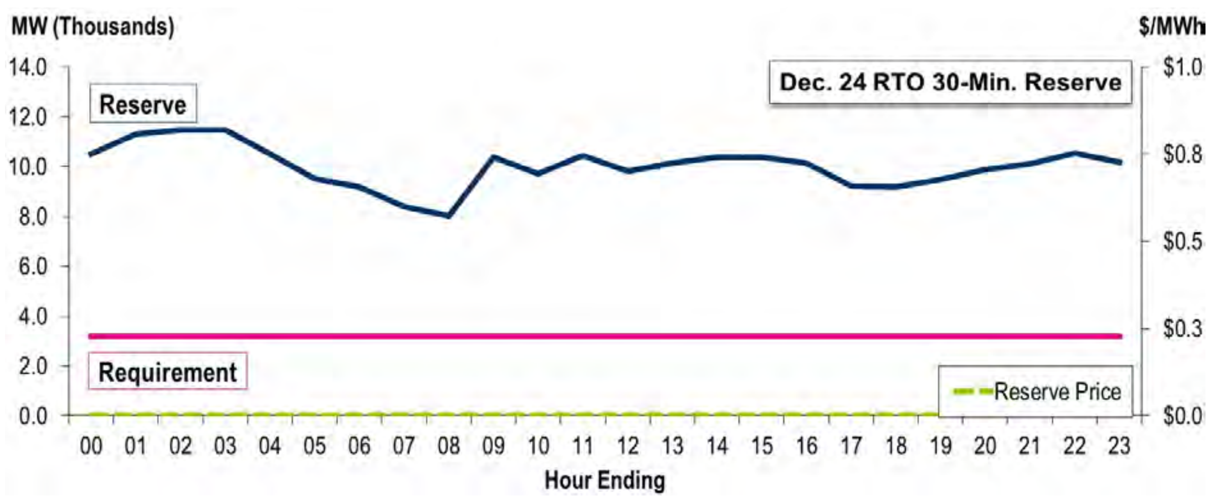


Figure 59. Dec. 24 30-Minute Reserve & Prices



Note that the Dec. 24 Day-Ahead Reserve Requirements were met at zero cost for the entire day, indicating that there were sufficient resources available to meet these requirements without adjusting their schedules based on the offer parameters submitted into the Day-Ahead Market.

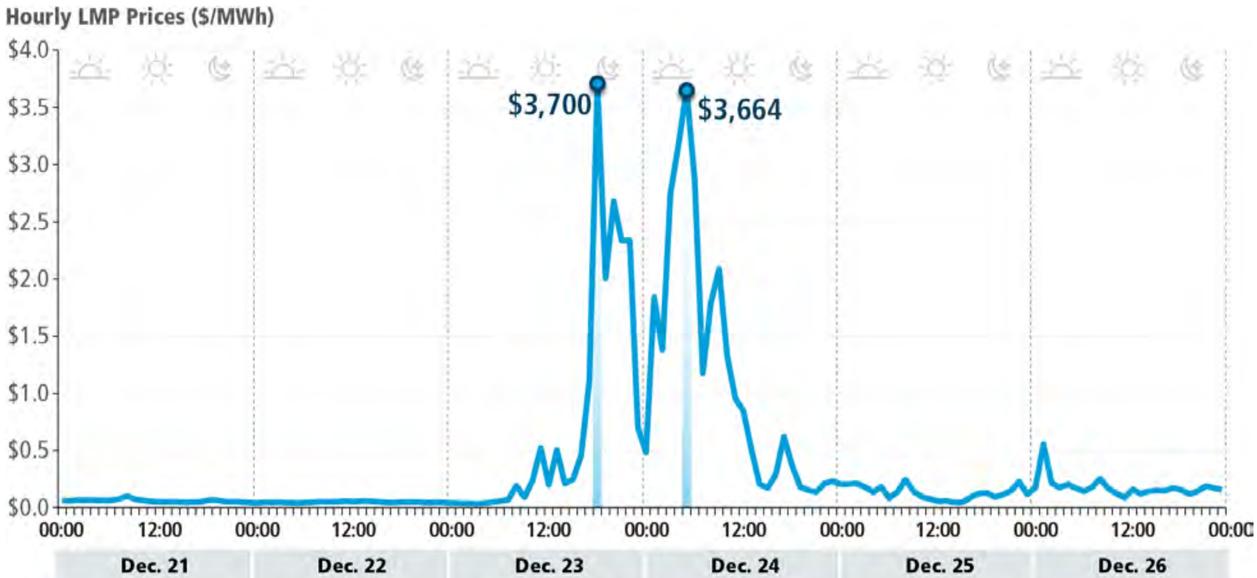
Real-Time Market Results

The Real-Time Energy Market uses the Real-Time Security Constrained Economic Dispatch (RT SCED) program, known as the "dispatch run," to determine the least-cost solution to balance supply and demand. The dispatch run considers resource offers, forecasted system conditions and other inputs in its calculations.

Real-Time LMPs and Regulation and Reserve Clearing Prices are calculated every five minutes by the Locational Price Calculator (LPC) program, in a process referred to as the pricing run, and are based on forecasted system conditions and the latest approved RT SCED program solution. Real-time prices are used to settle quantity deviations from day-ahead schedules in what is referred to as a balancing settlement.

Figure 60 presents the average Real-Time LMPs for Dec. 23 and Dec. 24.

Figure 60. Dec. 23 and Dec. 24 Hourly System Energy Prices



On Dec. 23 and 24, Real-Time LMPs across the system rose as high as $3,700/MWh on both days and were driven by fuel costs, stressed system conditions including reserve shortages, multiple emergency procedures declared by PJM operators, a high generator forced outage rate, and higher-than-expected load. In comparison, the average Real-Time LMP for the month of December 2022 was $122/MWh, while the average LMP for Dec. 21–26 was $386/MWh.

Congestion Impacts

A transmission constraint occurs when a physical limitation of a transmission facility is reached during normal or contingency system operations. When this occurs, the most economic generation cannot be delivered to the load due to physical limitations on transmission facilities. As a result, when there is a transmission constraint, more expensive generation that is electrically closer to the load must be dispatched in order to ensure that flows on transmission facilities are maintained within their operating limits.

To determine which generators have the most cost-effective benefit on relieving a transmission constraint, PJM calculates the dollar-per-megawatt effect of each generator on a transmission constraint and redispatches the lowest cost generators first to control the transmission constraint. The cost that the RT SCED will incur to control a transmission constraint is limited to the level of the Transmission Constraint Penalty Factor (TCPF), typically $2,000/MWh. The TCPF not only caps the cost of controlling actions used to control a transmission constraint but it is also the price level used to indicate that a transmission constraint cannot be controlled. This occurs when the actual or post-contingency flow on a transmission constraint exceeds the limit operators are controlling to.

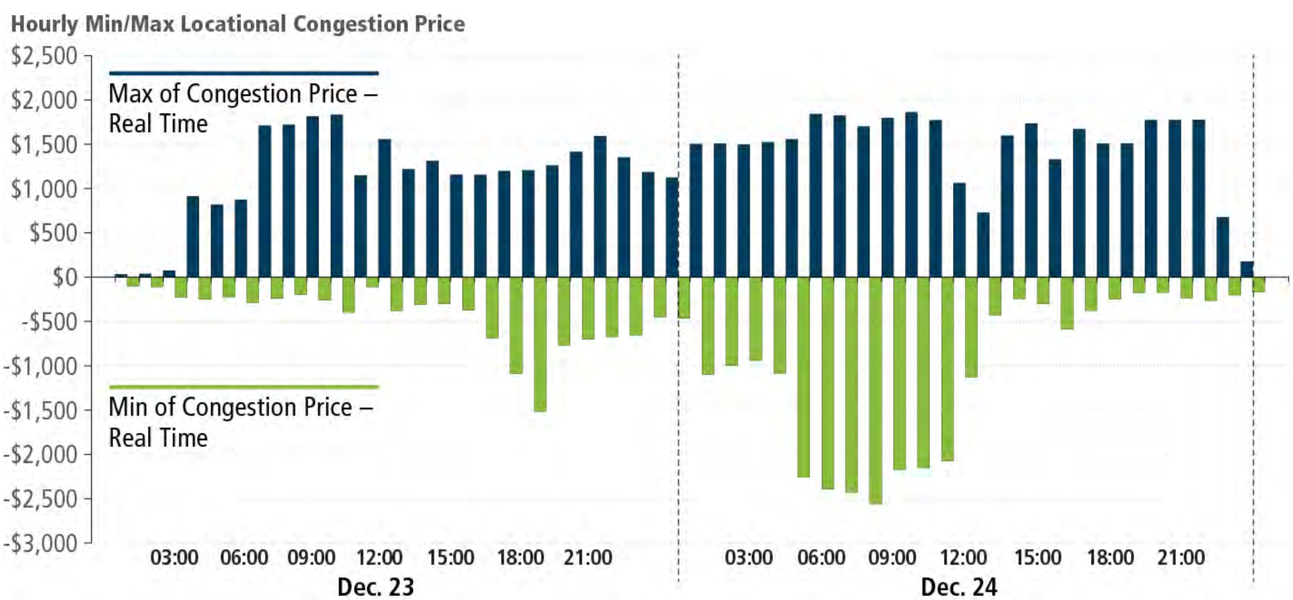
The underlying goal and intent of reflecting the TCPF in LMPs is to provide market signals that incentivize supply and/or load response to help relieve a constraint in the short term, while also incentivizing the development of additional supply, load response and/or transmission upgrades through long-term investments. Use of the TCPF, therefore, generally results in prices that signal short-term responses and longer-term investment that would be beneficial to the reliability of the transmission system and therefore have the intended impact.

On Dec. 23, 27 of the 35 active constraints in SCED bound at TCPF for at least one five-minute interval, indicating multiple locations of local scarcity within the PJM footprint. On Dec. 24, 28 of the 42 active constraints bound at the TCPF for at least one five-minute interval. While PJM maintains the ability to adjust the default level of the TCPF, no adjustments were made during Winter Storm Elliott, as all system constraints were effectively being controlled by resources available to PJM system operators.

The system pricing effects of the TCPF, and congestion in general, is locational. The TCPF is used to determine the Marginal Value of a transmission constraint when sufficient controlling actions do not exist to control the constraint at or below the applicable TCPF.

Figure 61 presents the impacts of congestion on the Real-Time Locational Congestion Price for Dec. 23 and Dec. 24.

Figure 61. Dec. 23 and Dec. 24 Congestion Prices



The locational aspect of load to constraints ultimately impacts pricing, as shown in Figure 62. Zonal prices reached as high as approximately $4,300 on Dec. 24.

Table 4 presents the binding constraints on high-voltage equipment that had a broader system impact on locational pricing on Dec. 23 and Dec. 24.

Table 4. Dec. 23 and Dec. 24 Binding Constraints on High-Voltage Equipment

Equipment Name (500 kV and Above)*	Zone	# of Intervals at TCPF	Dec. 23 (EPT)	Dec. 24 (EPT)
TRANSFER INTERFACE: AEP-DOM	N/A	129	09:35–22:30	00:05–23:50
JUNIATA 1 XFORMER H 500 KV	PPL	73	19:20–21:25	01:30 04:35–09:55
CONASTON-PEACHBOT 5012B 500 KV	BC	21	22:20–23:45	00:40
CABOT-KEYSTONE 5002B 500 KV	APS	1	12:25	
BROADFO2 T6 XFORMER H 765 KV	AEP	28	09:15–11:10 12:30–12:45 12:55	

Note: A complete list of binding constraints is available at Data Miner.

Figure 62 presents the locational impact of congestion for a sample interval on the evening of Dec. 23.

Figure 62. Dec. 23 17:00 Total Hourly Zonal LMP

Given that the System Energy Price cannot rise above $3,700/MWh, the difference can be attributed primarily to the impacts of congestion.

Figure 63 presents the locational impact of congestion for a sample interval on the evening of Dec. 24.

Figure 63. Dec. 24 08:00 Total Hourly Zonal LMP

FTRs were fully funded during the extent of Winter Storm Elliott. From Dec. 23 through Dec. 25, FTR target credits totaled $99,017,903.99. Day-ahead congestion, which is the sum of the target and surplus, over that same time period was $130,319,840.29, resulting in a $33,919,216.32 surplus. For further information on FTR accounting, please see PJM Manual 6, Section 8.

Balancing Congestion is captured in Figure 64 for the period between Dec. 20 and Dec. 26.

Figure 64. Balancing Congestion Dec. 20–26

On Dec. 23, Net Balancing Congestion was $22,134,094 and $23,504,649 for Dec. 24. Net Balancing Congestion is positive for both days, indicating some active real-time constraints were not triggered in the day-ahead solution. The reason for the imbalance is, in part, tied to the lower cleared load in the Day-Ahead Market compared to the actual load realized during the operating days of Dec. 23 and Dec. 24.

Real-Time Load and Prices

On both Dec. 23 and Dec. 24, PJM had insufficient reserves available to meet the reserve requirements. If during the execution of the pricing run, the Locational Pricing Calculator (LPC) determines that a reserve shortage exists, PJM deems this to be a reserve shortage, triggering shortage pricing. Shortage pricing is a market rule that ensures energy and reserve prices reflect the state of the system, both leading up to and during times of reserve shortages. A reserve shortage occurs when there are insufficient resources available to maintain the balance of generation, load and reserve requirements. PJM implements shortage pricing through the inclusion of the applicable Reserve Penalty Factors in the Real-Time LMP and reserve pricing calculations.

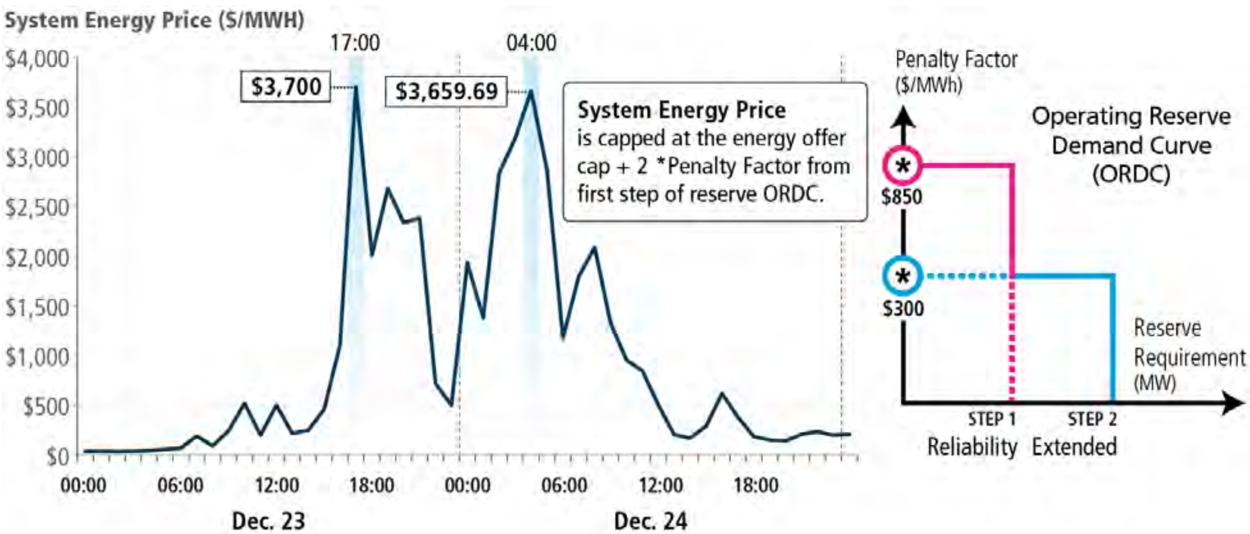
PJM uses Operating Reserve Demand Curves (ORDCs) to set the demand and willingness to pay for each of its reserve products. Like the TCPF, the ORDCs contain Reserve Penalty Factors that function as a cap on the $/MWh cost willing to be incurred to maintain a specific reserve requirement in a specific location. All Reserve Penalty Factors are currently set at either $300/MWh or $850/MWh depending on the segment of the ORDC.

The maximum reserve prices are capped as follows:

- Synchronized Reserves are capped at two times the penalty factor ($1,700).
- Non-Synchronized Reserves are capped at 1.5 times the penalty factor ($1,275).
- Secondary Reserves capped at one time the penalty factor ($850).

Figure 65 presents the System Energy Price on Dec. 23 and Dec. 24:

Figure 65. Dec. 23 and Dec. 24 System Energy Price



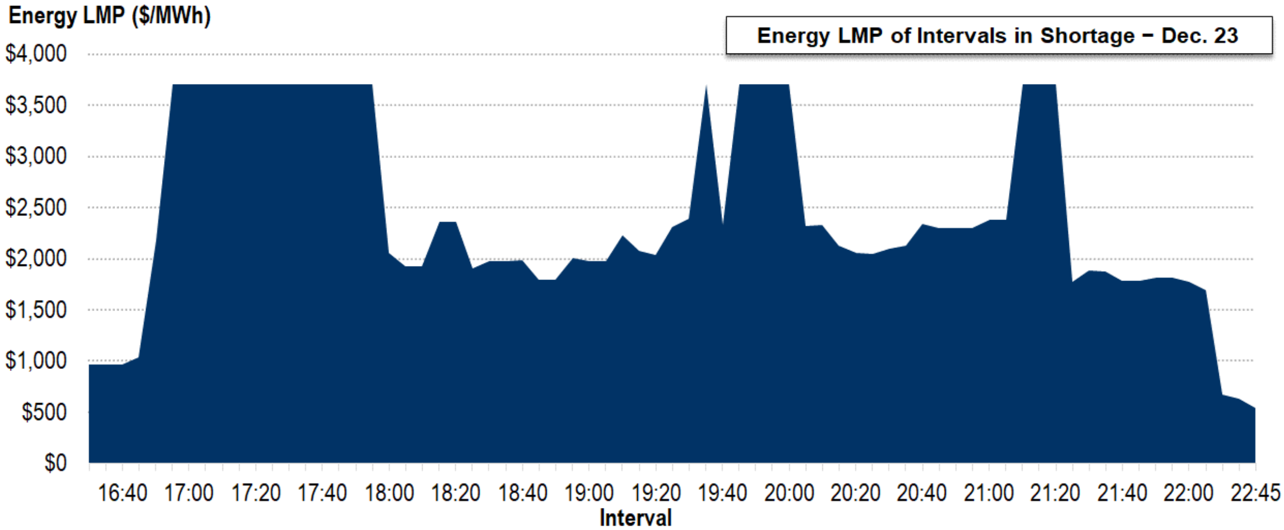
There were 71 shortage intervals approved by PJM Dispatch between 16:30 and 22:45 on Dec. 23. Table 5 reflects the breakdown by Reserve Sub-Zones.

Table 5. Shortage Intervals by Reserve Sub-Zones

	Reserve Penalty Factors
45	MAD & RTO – Primary
21	MAD & RTO – Primary & Synchronized
2	MAD & RTO – Primary & RTO – Synchronized
3	RTO Primary

Figure 66 presents the LMPs during the shortage intervals on Dec. 23.

Figure 66. Dec. 23 LMPs During Shortage Intervals



PJM currently has rules in place that place a cap on the System Energy Price of $3,700/MWh. This cap was reached during various intervals on Dec. 23 as shown Figure 66. Total LMPs exceeded $3,700/MWh in some locations during these shortage intervals due to the addition of congestion and losses.

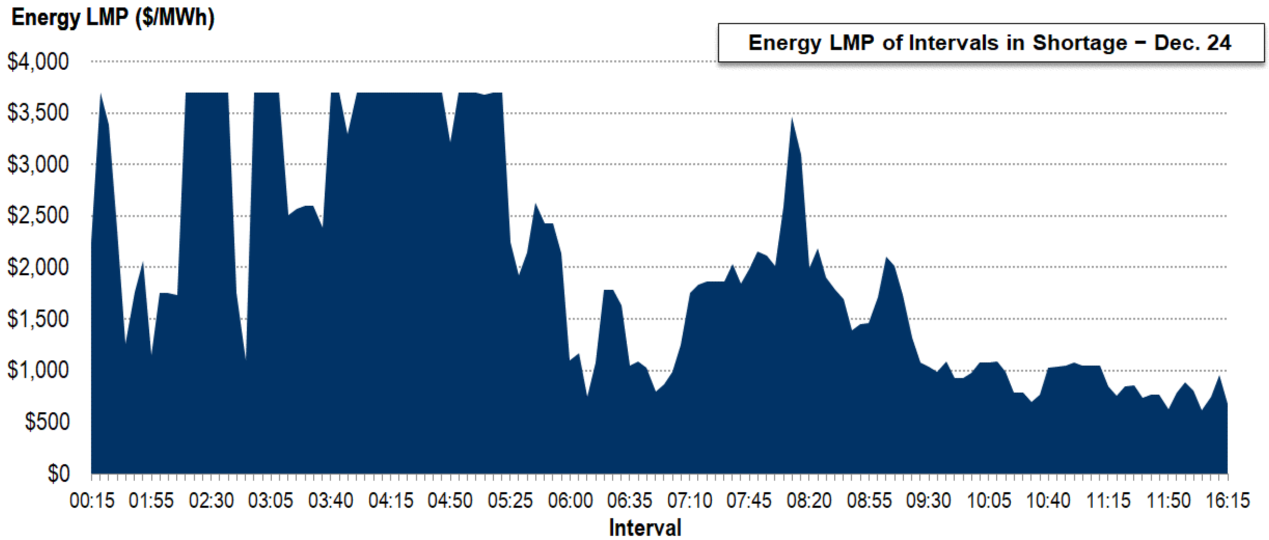
There were 134 shortage intervals approved by PJM Dispatch between 00:15 and 16:15 on Dec. 24. Table 6 presents the breakdown of the shortage intervals by Reserve Sub-Zones.

Table 6. Shortage Intervals by Reserve Sub-Zones

	Reserve Penalty Factors
69	MAD & RTO – Primary
37	MAD & RTO – Primary & Synchronized
16	MAD & RTO – 30-Minute
1	MAD & RTO – Primary & RTO – Synchronized
11	RTO Primary

Similarly, Figure 67 presents the LMPs during the shortage intervals on Dec. 24.

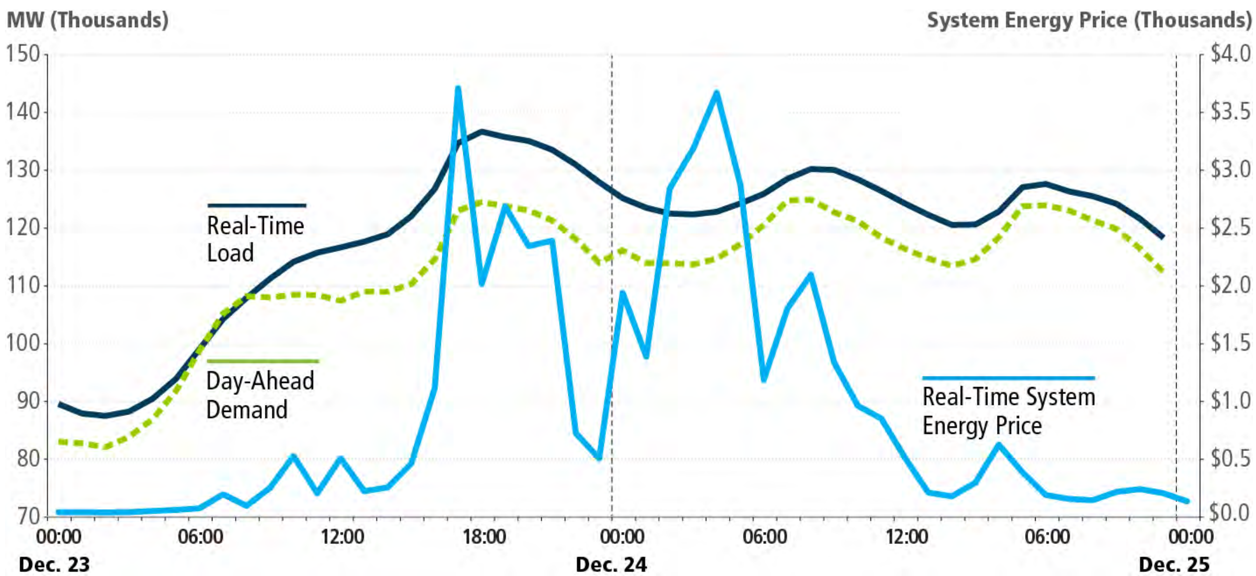
Figure 67. Dec. 24 LMPs During Shortage Intervals



On Dec. 24, the System Energy Price was $3,700/MWh during shortage intervals, as shown in Figure 67. During these intervals, there were locations on the system where LMP exceeded this price level when congestion and losses were also included.

Starting in the evening on Dec. 23, PJM experienced elevated pricing for energy and reserves, consistent with the multiple emergency procedures that were initiated due to extreme system conditions. Factors driving those extreme conditions included higher-than-anticipated loads and unprecedented forced generator outages. As a result, Real-Time Market operations accurately reflected multiple five-minute intervals with strained power balance, locational congestion management and extended periods of shortage pricing. Figure 68 overlays the System Energy Price, day-ahead forecasted load and real-time load.

Figure 68. System Energy Price, Day-Ahead Forecasted Load and Real-Time Load

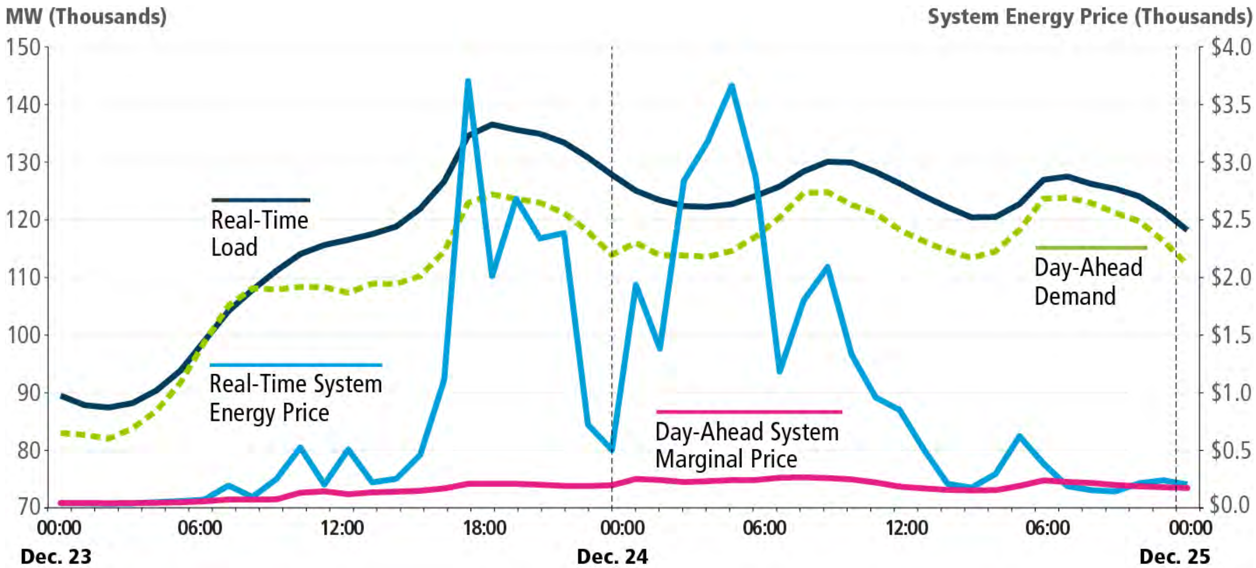


Real-Time LMPs are calculated based on five-minute intervals. Both generation and emergency Demand Response resources can and did set the price.

Day-Ahead Versus Real-Time Prices

Figure 69 presents the average day-ahead hourly load and prices compared to the real-time average load and prices.

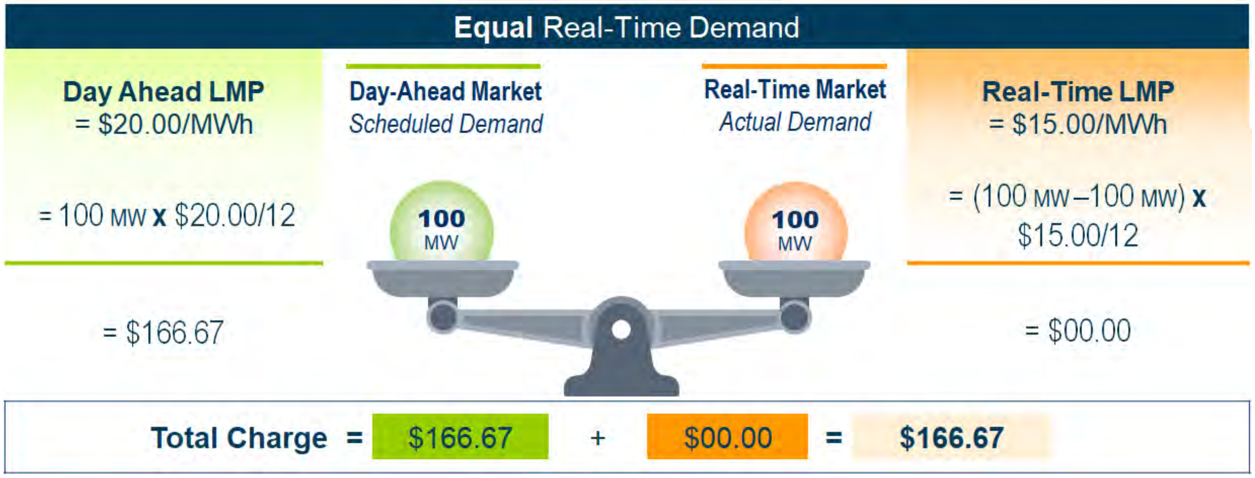
Figure 69. Day-Ahead and Real-Time Load and Day-Ahead and Real-Time Hourly System Energy Price



There is a significant difference between the day-ahead and the actual real-time load (approximately 12,172 MW), as shown in Figure 69. The difference between the Day-Ahead and Real-Time Market prices, due primarily to the unavailability of generation in real-time and under-forecasting of load in day-ahead, creates a potential for exposure to Real-Time pricing. Cleared day-ahead demand for Dec. 23 was 10,400 MW lower than the actual metered load realized at the peak. In comparison, cleared day-ahead demand for Dec. 24 was approximately 9,000 MW lower than the actual metered load realized during the morning peak. The demand that was cleared in the Day-Ahead Market was subject to the Day-Ahead LMP of $207/MWh on Dec. 23 and $262/MWh on Dec. 24. Real-time load that was not hedged in the Day-Ahead Market during the peak periods on these days was exposed to Real-Time LMPs of approximately $3,700 in both instances.

Figure 70 presents an example of a settlement example for an LSE that is fully hedged.

Figure 70. Fully Hedged LSE Settlement Example



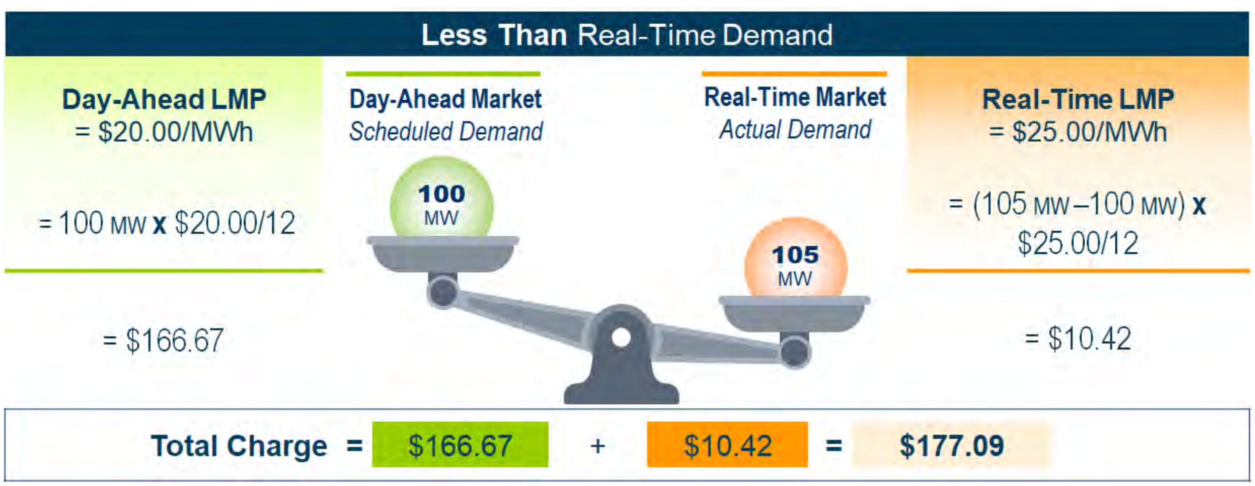
In Figure 70, the LSE submitted a 100 MW bid in the Day-Ahead Market. The Day-Ahead Market cleared at $20.00/MWh. The Day-Ahead Market settlement for this five-minute interval is the day-ahead scheduled demand multiplied by the Day-Ahead LMP divided by 12 (there are 12 five-minute intervals in an hour), or $166.67.

In the Real-Time Market, the LSE's actual demand is 100 MW. The balancing settlement for this five-minute interval is the difference between Real-Time Market actual demand and the Day-Ahead Market scheduled demand, multiplied by the Real-Time Market LMP divided by 12. Since the LSE's Real-Time Market actual demand and the Day-Ahead Market scheduled demand are both 100 MW, the LSE is fully hedged and is not exposed to the Real-Time Market prices. The Real-Time Market settlement is $0.00.

The total charge for this LSE for this sample five-minute interval is the Day-Ahead Market charge plus the Real-Time Market charge, or $166.67.

Figure 71 presents a settlement example for an LSE that is under-hedged.

Figure 71. Under-Hedged Load Settlement Example



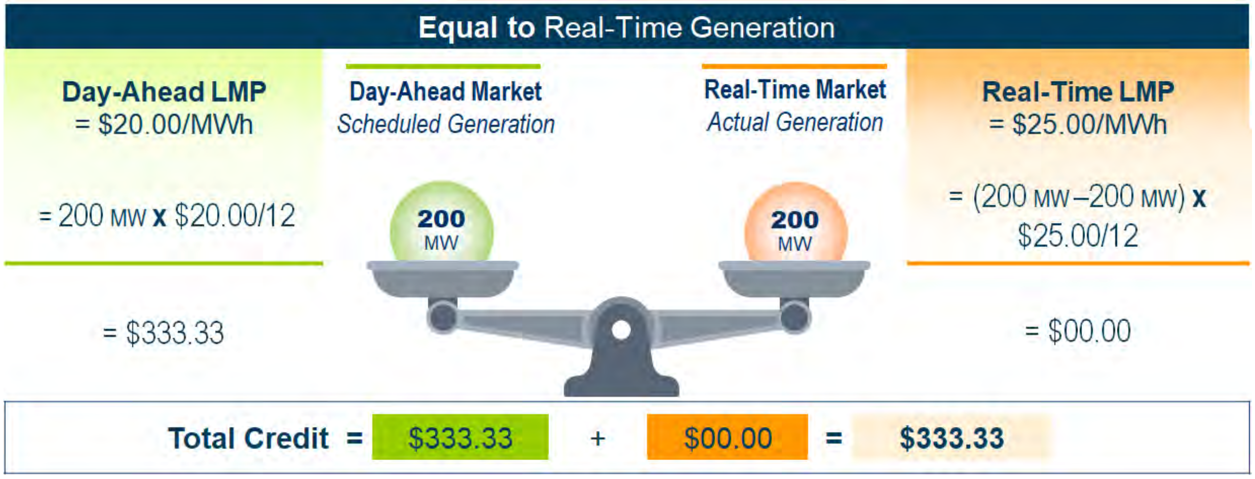
In Figure 71, the LSE submitted a 100 MW bid in the Day-Ahead Market. The Day-Ahead Market cleared at $20.00/MWh. The resulting Day-Ahead Market settlement for this sample five-minute interval is the Day-Ahead scheduled demand multiplied by the Day-Ahead Market LMP, in this case the Day-Ahead Market settlement is $166.67.

In real time, the Load Serving Entity's actual demand is 105 MW, 5 MW greater than the Day-Ahead Market. Therefore, the LSE is exposed to the Real-Time Market prices or is "under-hedged" for the additional 5 MW. The LSE purchases the 5 MW at the Real-Time LMP. The balancing settlement for this sample five-minute interval is the difference between the Real-Time actual demand minus the Day-Ahead Market scheduled demand. In this case, the LSE scheduled 100 MW in the Day-Ahead Market and the actual demand is 105 MW. The Real-Time Settlement is therefore 5 MW multiplied by the Real-Time Market LMP of $25.00/MWh, divided by 12, for a total of $10.41.

The total charge for this LSE for this five-minute interval is the Day-Ahead Market charge plus the Real-Time Market charge, or $177.09

Figure 72 presents a settlement example for a generator that is fully hedged.

Figure 72. Fully Hedged Generator Settlement Example



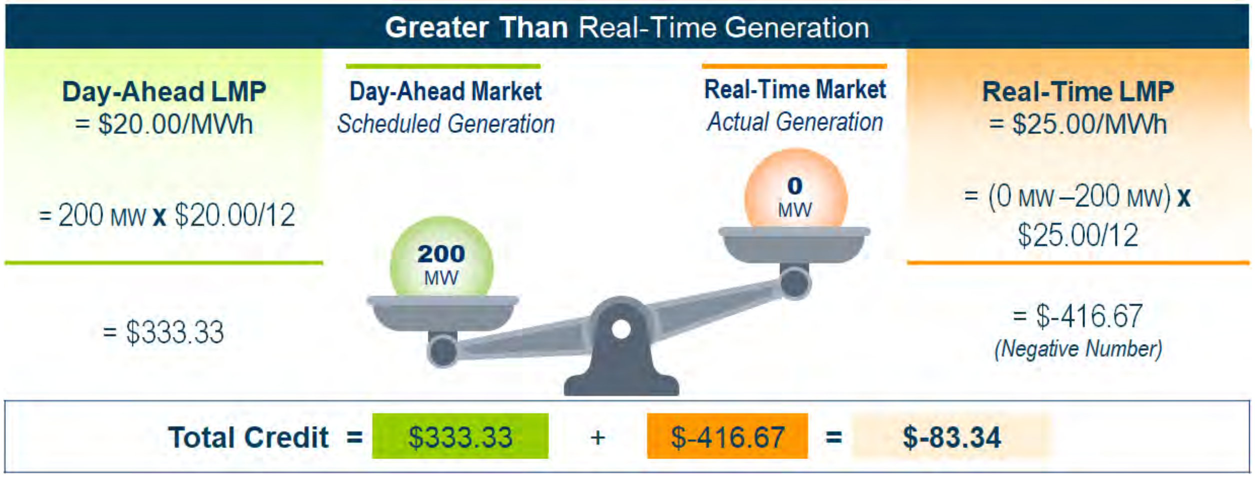
In Figure 72, the Generator submitted a 200 MW offer in the Day-Ahead Market. The Day-Ahead Market cleared at $20.00/MWh. The Day-Ahead Market settlement for the generator is the Day-Ahead Market scheduled generation multiplied by the Day-Ahead Market price, or 200 MW multiplied by $20.00 MW/h, divided by 12. The Day-Ahead Market credit for this generator is $333.33.

In real time, the Generator produced 200 MW. The balancing settlement is the difference between the Real-Time Market actual generation and the Day-Ahead Market scheduled generation. In this case, the generator was committed for 200 MW in Day-Ahead Market and produced 200 MW in real time. The generator is fully hedged (not exposed to real-time prices.) The balancing settlement is therefore $0.00.

The Total Credit for this generator for this five-minute interval is $333.33.

Figure 73 presents a settlement example for a generator that is committed in the Day-Ahead Market and trips during real time.

Figure 73. Day-Ahead Committed Generator That Trips in Real-Time Settlement Example



In Figure 73, the generator submitted a 200 MW offer in the Day-Ahead Market. The Day-Ahead Market cleared at $20.00/MWh. The Day-Ahead Market settlement for the generator is the Day-Ahead Market scheduled generation multiplied by the Day-Ahead Market price, or 200 MW multiplied by $20.00 MW/h divided by 12. The Day-Ahead Market credit for this generator is $333.33.

In real time, the generator tripped and therefore did not produce any energy. The balancing settlement is the difference between the Real-Time Market actual generation and the Day-Ahead Market scheduled generation. In this case, the generator was committed for 200 MW in the Day-Ahead Market but produced 0 MW in the Real-Time Market. The generator needs to buy back the megawatts committed in the Day-Ahead Market at the Real-Time LMP. The balancing settlement for this five-minute interval is the difference between the Real-Time Market actual generation and the Day-Ahead scheduled generation, multiplied by the Real-Time Market LMP (divided by 12). The balancing settlement for this five-minute interval is -$416.67.

The total credit for this generator for this five-minute interval is -$83.34.

Interchange

Figure 74 and Figure 75 provide hourly net interchange values between PJM and neighboring market areas NYISO and MISO along with interface price values for PJM and the neighboring market areas. Interface pricing enables Market Participants to the profitability of scheduling energy transfers between or through neighboring Balancing Authorities.

During periods where the system is stressed and internal supply is close to or inadequate to meet energy and reserve needs, interface prices are used to incentivize Market Participants in neighboring regions to sell available power to PJM to relieve emergency conditions. On Dec. 23 and Dec. 24, interchange flows were generally into PJM from NYISO, which is reflected in the interface prices. Conversely, interchange flows for both days were generally out of PJM to MISO and our southern non-market neighbors [Tennessee Valley Authority (TVA), Louisville Gas and Electric Company and Kentucky Utilities Company (LGE-KU), Duke Energy Progress East (DEP-East), and Duke Energy Progress West (DEP-W)]. In those cases, system conditions were more stressed in the neighboring areas.

Figure 74. NYISO Net Interchange

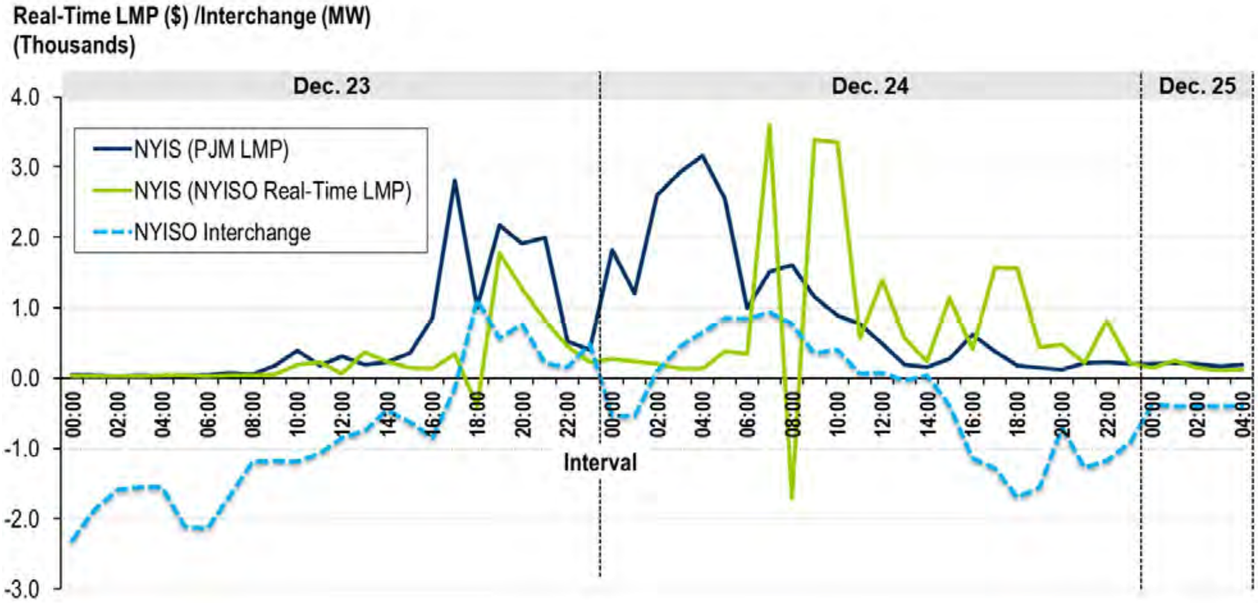


Figure 75. MISO Net Interchange

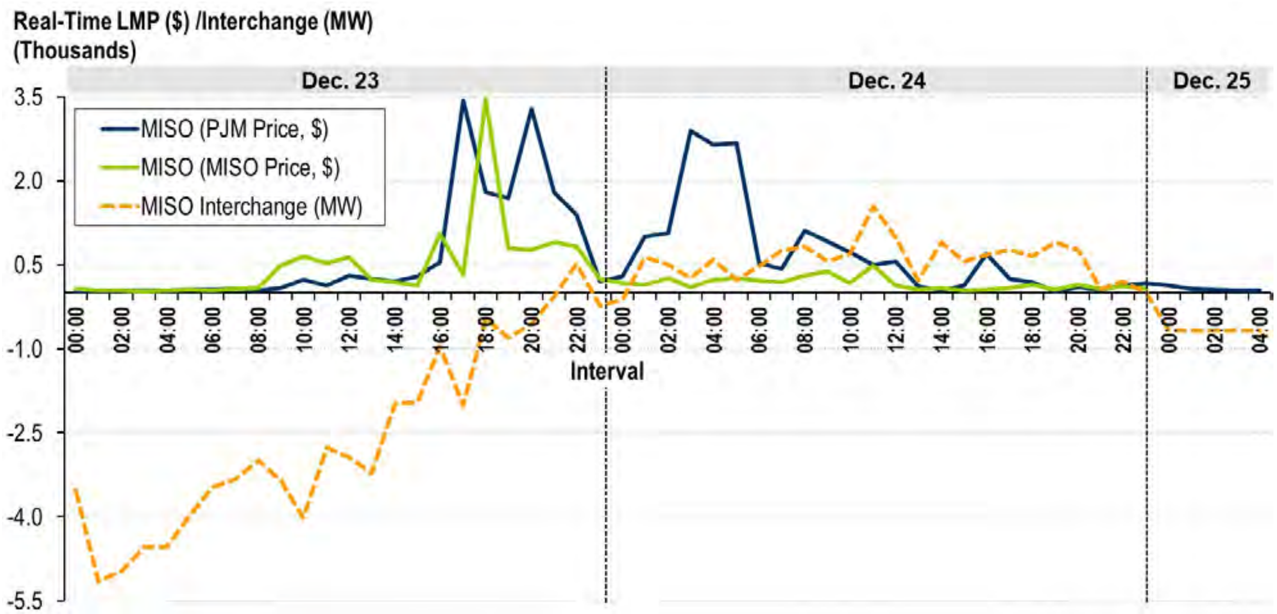


Figure 76 provides hourly net interchange values between PJM and the aggregate net interchange for LG&E-KU, TVA, Duke, DEP-East, and DEP-West, along with interface price values for PJM.

Figure 76. South Net Interchange

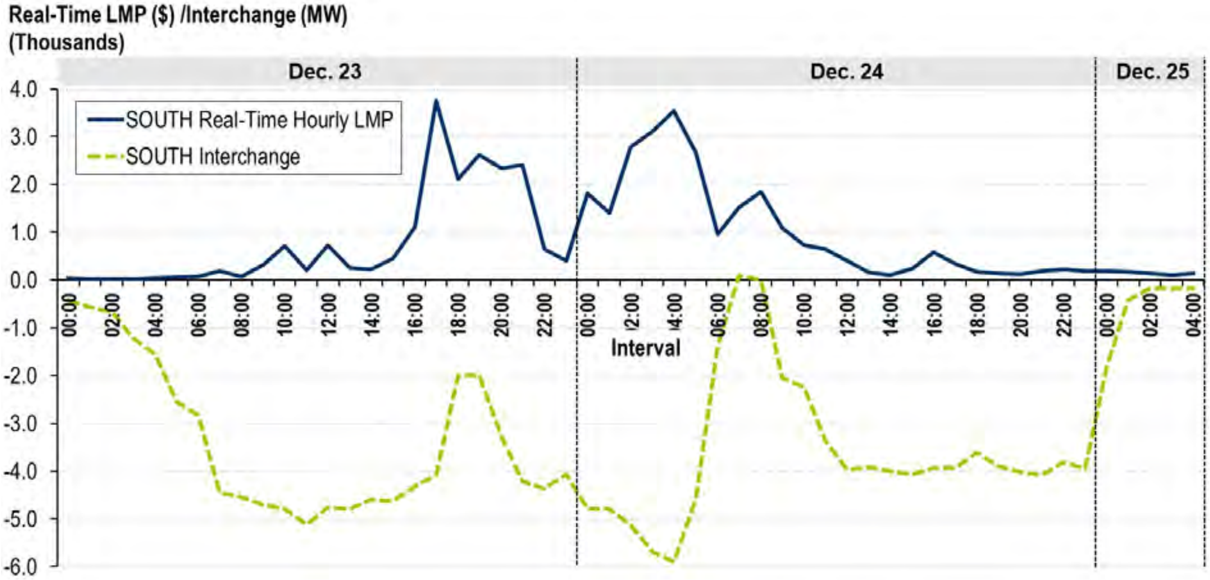
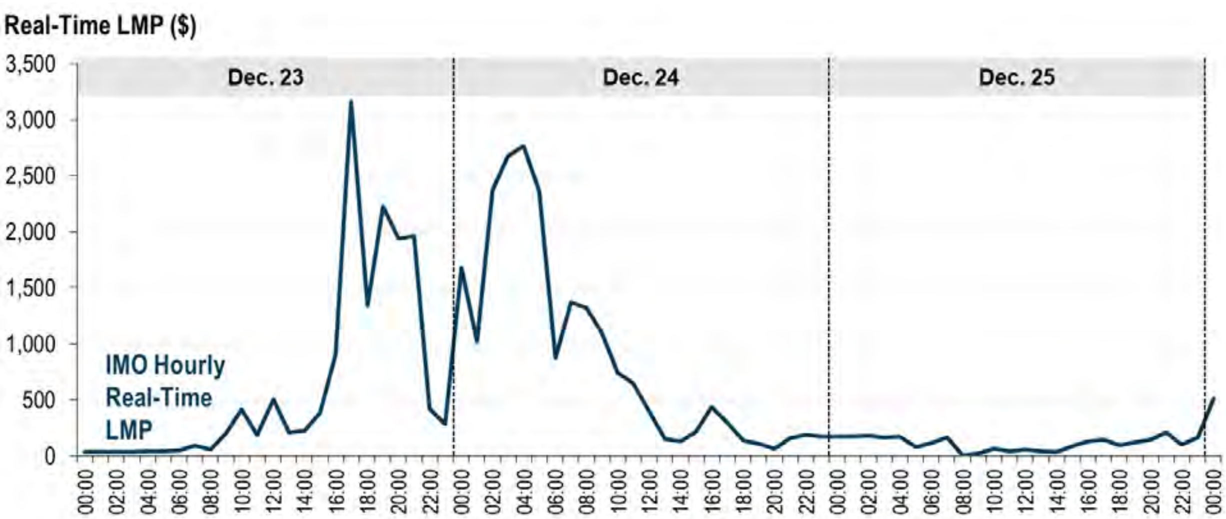


Figure 77 provides hourly pricing for the IMO interface. This information can be used by Market Participants during real time to make energy transfer decisions.

Figure 77. IMO Net Interchange



Ancillary Services: Regulation and Reserves

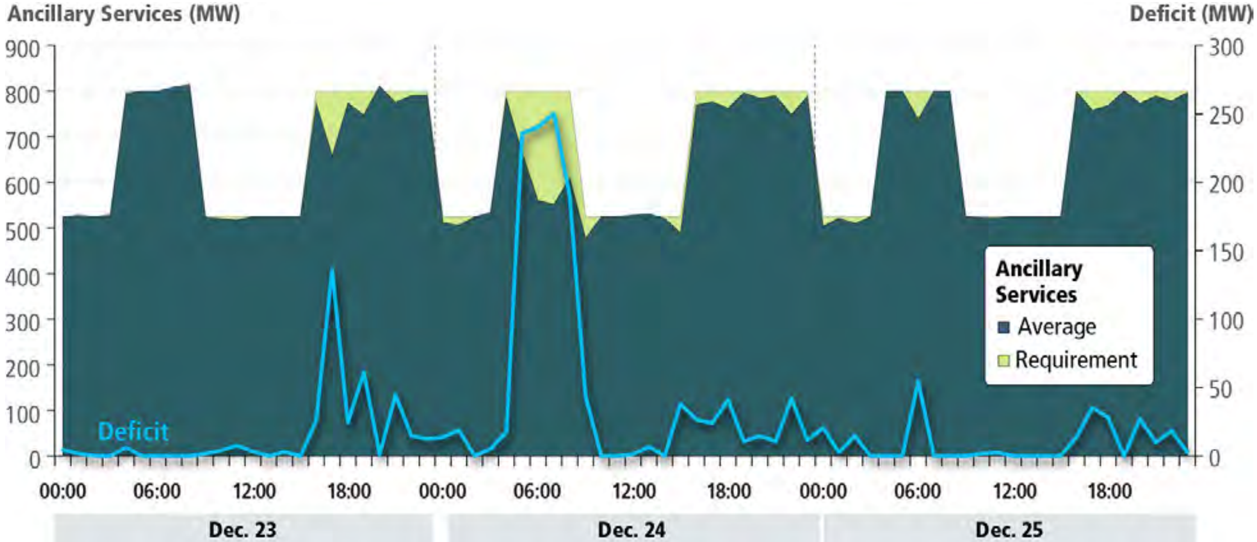
During Winter Storm Elliott, high prices for regulation, synchronized reserve, and Non-Synchronized Reserves occurred at the same time as high Real-Time Energy LMPs. During these stressed conditions, ancillary service prices increased as the reserve margin decreased, and system capacity competed to meet the ancillary services requirement while maintaining power balance.

Regulation Market Results

Regulation service corrects for short-term changes in electricity use that might affect the stability of the power system. It helps match generation and load and adjusts generation output to maintain the desired system frequency of 60 hertz. PJM's Regulation Market aligns compensation with actual performance for resources that provide regulation service. Resources are compensated for their accuracy, speed and precision of response in providing regulation service to the system.

On Dec. 23, as well as Dec. 24, PJM was deficit regulation, as presented in Figure 78, which presents the regulation megawatts, on average, by hour:

Figure 78. Regulation MW, on Average, by Hour

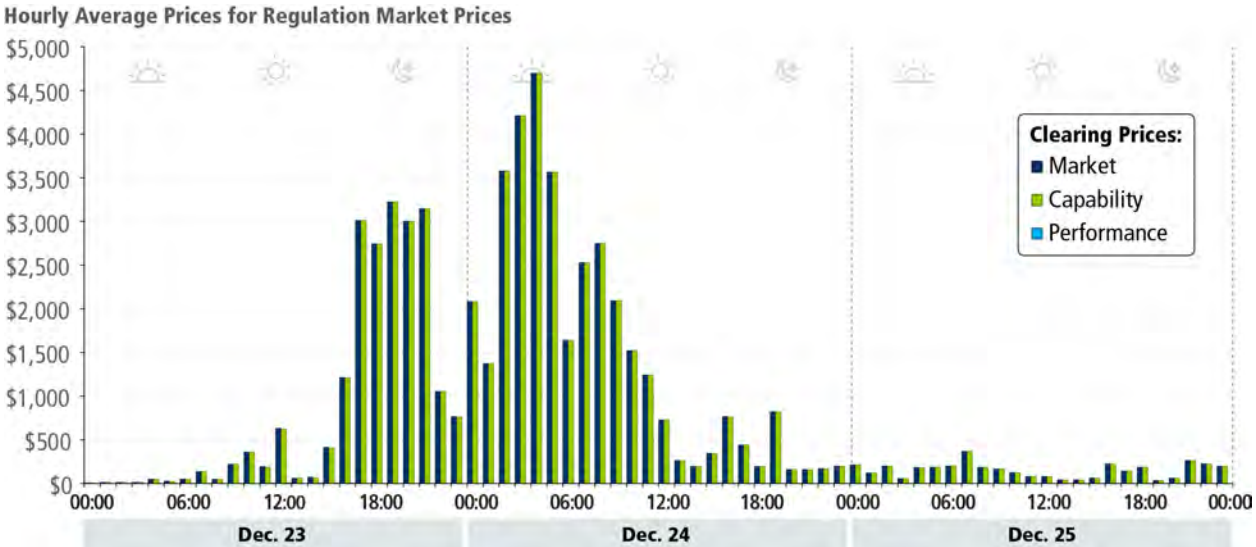


The regulation deficit is caused by the generator availability issues detailed in this report that resulted in a lack of available regulation-capable resources to commit. The regulation price spikes seen on Dec. 23 and Dec. 24 can be attributed to the low performance factor of the marginal unit for regulation as high-performing generators were being used for energy and reserves instead of regulation. High lost opportunity costs (LOC) were also a contributing factor to the high regulation prices. Recall that LOC is intended to capture foregone energy revenues from providing a service other than energy. When those foregone energy revenues are high because energy prices are high, regulation LOC and regulation prices can also be high to ensure resources are incentivized to provide needed regulation and not energy.

Unlike reserves, regulation is not co-optimized with energy in real-time. Similarly, there is also no explicit mechanism for shortage pricing of regulation as there is for reserves. As stated, regulation prices rose and fell roughly in correlation with energy prices during the evening of Dec. 23 and morning of Dec. 24 because of the calculation of regulation lost opportunity costs based on the high LMPs during these periods, not because of the regulation shortages.

Figure 79 presents the hourly average prices for RMCP for Dec. 23, 24 and 25.

Figure 79. Dec. 23, 24 and 25 Hourly Average Prices for RMCP



For more information on how the Regulation Market prices are calculated, please reference Manual 11, Section 3.

Reserve Market Price Trends

Reserves represent the generating capability that is "standing by," ready for service in the event that something happens on the power system, such as the loss of a large generator. The severity of the event determines how quickly the reserves have to be picked up.

In Oct. 2022, PJM implemented Reserve Price formation, resulting in the following changes:

- Consolidation of Tier 1 and Tier 2 Synchronized Reserve products
- Alignment of reserve products in day-ahead and real-time to ensure that the reserves needed for real-time operation are recognized on a forward basis during the scheduling processes for the next operating day
- Flexible modeling of reserve subzones

Figure 80 presents the market clearing prices (MCPs) for Synchronized Reserve (SRMCP), Non-Synchronized Reserve (NSMCP), and Secondary Reserve Market Clearing Price (SecRMCP) for Oct. 2022 through Dec. 2022. Notwithstanding Dec. 2022, the SRMCP, NSRMCP and SecRMCP prices have been at or near $0.00/MWh since the Oct. 2022 implementation of the Reserve Price Formation changes.

Figure 80. SRMCPs, NSMCPs and SecRMCPs

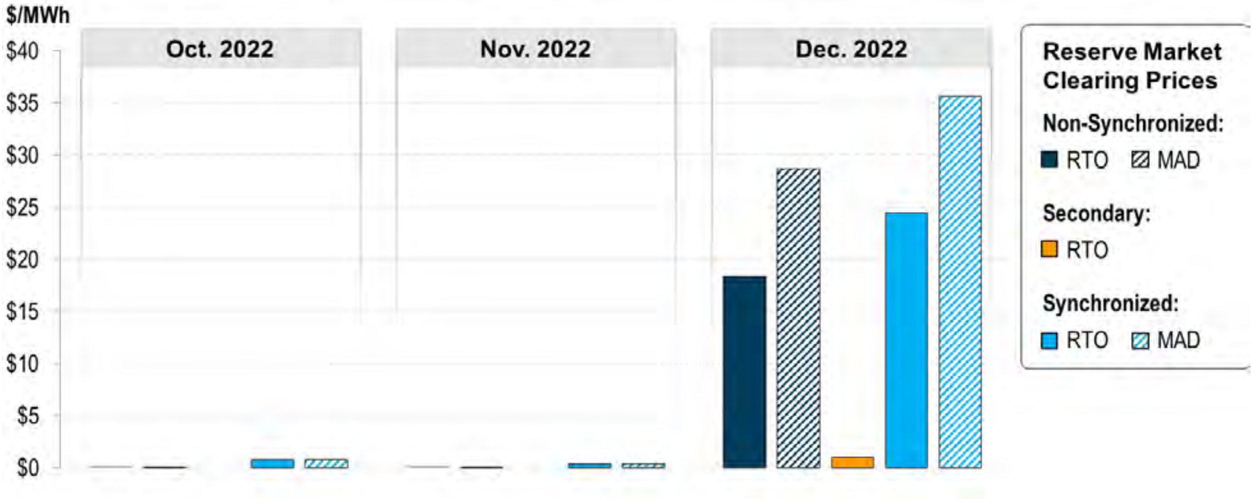


Figure 81 presents daily max and daily average SRMCPs since Oct. 1, 2022. This figure shows that the drivers of the high monthly averages SRMCPs observed in Dec. 2022 and displayed in Figure 80 are driven almost entirely by the operational events and market outcomes related to Winter Storm Elliott.

Figure 81. Shortage Pricing Impacts on SRMCP

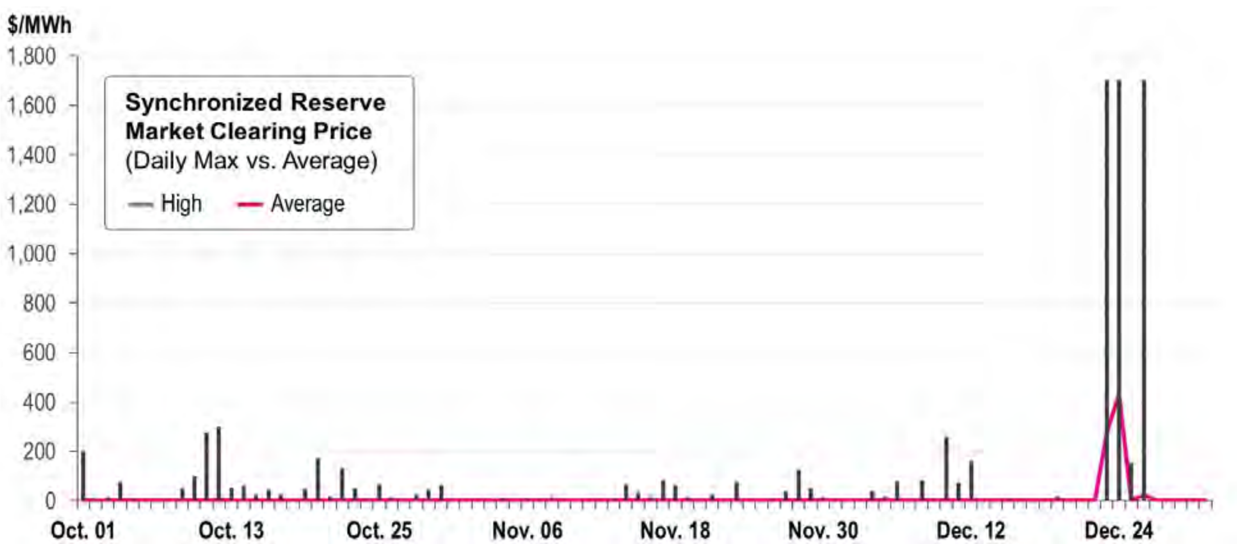
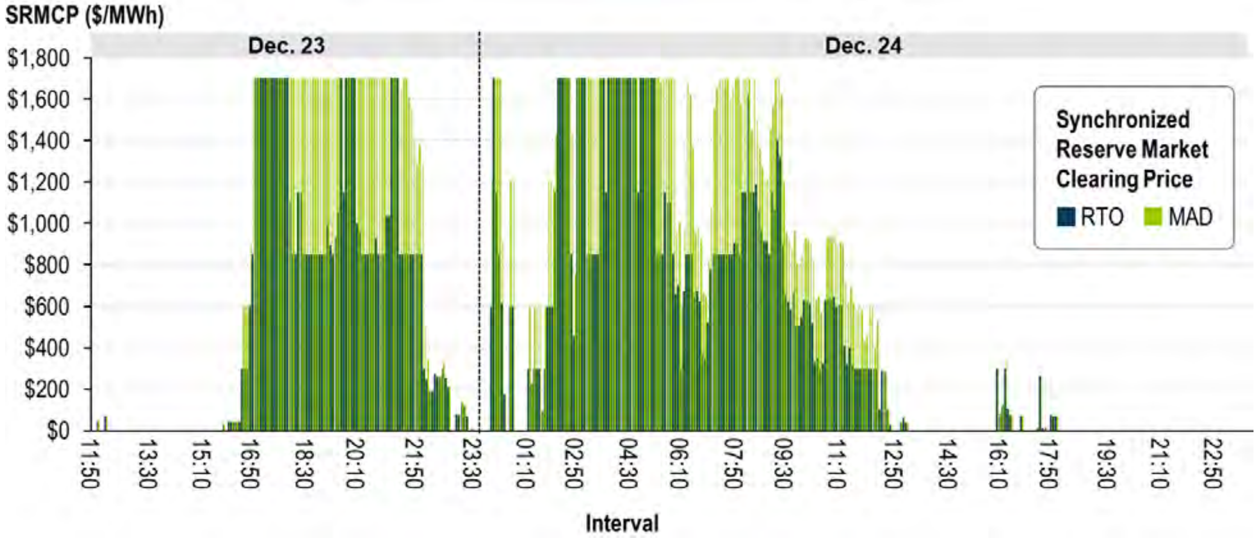


Figure 82 presents the Real-Time SRMCPs for Dec. 23 and Dec. 24.

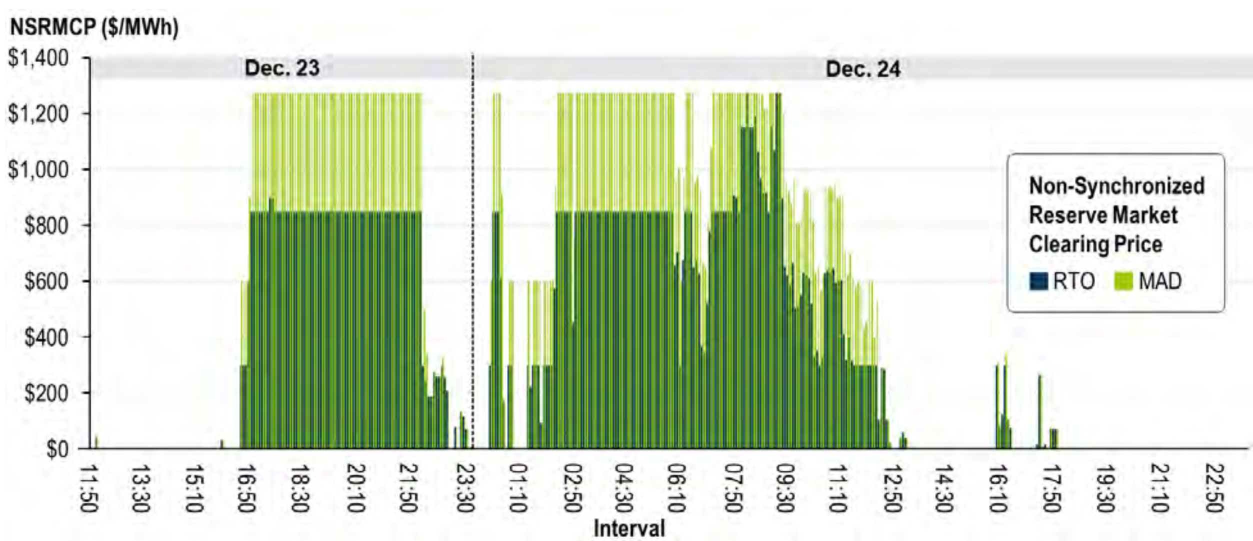
Figure 82. Dec. 23 and 24 Real-Time SRMCPs



The SRMCPs in many intervals are either at a level of $850/MWh or $1,700/MWh depending on the reserve product that was short and the location it was short. The price level of $1,700/MWh represents the price cap that exists for this product.

Figure 83 presents the Real-Time NSRMCPs for Dec. 23 and Dec. 24.

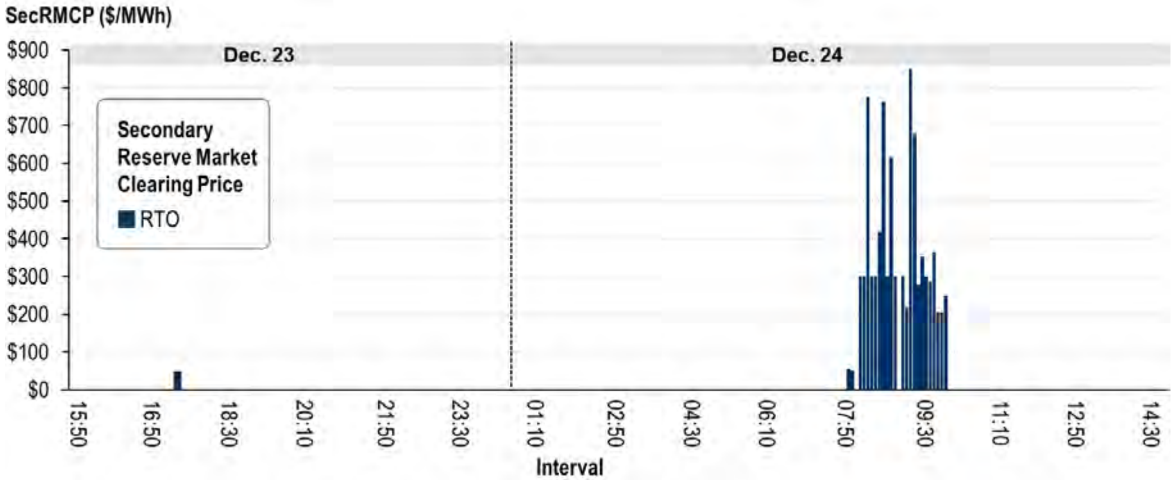
Figure 83. Dec. 23 and Dec. 24 Real-Time NSRMCPs



The Non-Synchronized Reserve Market Clearing Price (NSRMCP) is the clearing price paid to offline resources that can start within 10-minutes and be used to satisfy the Primary Reserve and 30-minute requirements. Market Sellers offer prices for the Non-Synchronized Reserve and Secondary Reserve products are $0.00/MWh; however, a Non-Synchronized Reserves LOC is estimated by the PJM market clearing engines. This LOC represents the foregone revenue an eligible offline resource could have received if had operated, given the forecasted LMP produced by the IT SCED engine. The current price cap Non-Synchronized Reserve is 1.5 times the Reserve Penalty Factor of $850/MWh, or $1,275/MWh.

Figure 84 presents the Real-Time SecRMCPs for Dec. 23 and Dec. 24.

Figure 84. Dec. 23 and Dec. 24 Real-Time SecRMCPs



The SecRMCP was $0.00/MWh of most of the Winter Storm Elliot event except for approximately two hours on Dec. 24. During that period, the SecRMCP reached its price cap of $850/MWh for one interval.

Given the observed issues with reserve performance and availability during Winter Storm Elliott and other inefficiencies PJM believes exist in the design of these markets, PJM believes there is a need to evaluate various aspects of its reserve market design including the products, offer structure, levels procured, performance incentives, and deployment practices to ensure the necessary amount of reserves is being procured, priced by the market and incentivized to perform at a high level. PJM plans to bring a Problem Statement and Issue Charge to Stakeholders to address these items in the near future.

Synchronized Reserve Events and Reserve Performance

As described earlier, Synchronized Reserves are reserve generators that are already synchronized to the grid and can be loaded within 10 minutes. PJM carries enough Synchronized Reserves to cover the unexpected loss of the largest single generation contingency operating on the PJM system at that time, plus a small margin. Typically, this reserve requirement is approximately 1,600 MW.

The conditions of Winter Storm Elliott led to PJM requesting the loading of Synchronized Reserve generation on five separate occasions during the two-day period of Dec. 23 and Dec. 24. Four of these events were called in response to a low ACE caused by increasing load combined with generation tripping and start failures. One of the events was called in direct response to the loss of a unit.

Five Synchronized Reserve Events over a two-day period is very unusual. Note that the average duration between Synchronized Reserve Events in 2021 was 22 days. All five of the events during Winter Storm Elliott exceeded 10 minutes in duration. Two of the events exceeded one hour in duration at 1 hour 51 minutes and 1 hour 27 minutes. The average duration for these five events was 53 minutes and 17 seconds. The average duration of the other 18 Synchronized Reserve Events that occurred in 2022 was 9 minutes and 57 seconds.

System conditions and ACE control prevented the PJM system operators from ending these Synchronized Reserve Events earlier, as all available reserve megawatts were required to support the ACE and provide overall system control. Table 7 provides details of these five events.

Table 7. Five Synchronized Reserve Events

Event Date	Start (EST)	End (EST)	Duration	Zone	Reason	PAI in effect
Dec. 23	10:14	10:25	00:11:07	RTO	Low ACE	No
	16:17	18:09	01:51:29			Yes (17:30–18:09)
Dec. 24	00:05	00:30	00:25:43			No
	02:23	02:54	00:30:35		Unit Trip	No
	04:23	05:51	01:27:32		Low ACE	Yes (04:25–01:27)

PJM measures the response of resources with a Real-Time Synchronized Reserves commitment as detailed in PJM Manual 11, Section 4.5. Note, Day-Ahead Synchronized Reserve commitments are reevaluated in real time, and only those resources that have a real-time commitment are obligated to respond.

For each Synchronized Reserve Event, the magnitude of each resource's response is the difference between the resources' output at the start of the event and its output 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, resource output at the start of the event is defined as the lowest telemetered output between one minute prior to and one minute following the start of the event. Similarly, a resource's output 10 minutes after the event is defined as the greatest output achieved between nine and 11 minutes after the start of the event.

Also relevant for the events lasting longer than 10 minutes, all resources must maintain an output level greater than or equal to that which was achieved as of 10 minutes after the event for the duration of the event or 30 minutes from the start of the event, whichever is shorter. The response actually credited to a given resource will be reduced by the amount the megawatt output of that resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. There is no current performance evaluation for events lasting longer than 30 minutes, beyond the initial 30-minute period.

Although not relevant for these events, in cases where an event lasts less than 10 minutes, resources are credited with the amount of reserve capacity they are assigned.

Since PJM's implementation of the Reserve Price Formation changes on Oct. 1, 2022, the entirety of the Synchronized Reserve Requirement is assigned to specific resources in a co-optimization with energy. Resources assigned these reserves each Real-Time interval have an obligation to perform or face a penalty in the amount of non-performance. This penalty consists of two components as follows:

1 | The resource is credited for Synchronized Reserve for the amount that actually responded for all intervals in which the resource had an assignment (either self-scheduled or assigned) on the day the event occurred.

2 | An obligation to refund at the Synchronized Reserve Market Clearing Price the amount of the shortfall for all Real-Time Settlement Intervals that the resource had an assignment for a period of the lesser of a) the average number of days between events or b) the number of days since the resources last non-performance.

Synchronized Reserve response to the five events during Winter Storm Elliott for resources assigned reserves was generally poor.

- The highest response was 86.4% of assignment, as seen during the Dec. 23, 10:14 event, which was the first Synchronized Reserve deployment during Winter Storm Elliott. Not coincidentally, this was also the shortest of the five events at 11:07 minutes.

- The lowest response was 16.8% of assignment, as seen during the Dec. 24, 04:23 event.
- The average response of these five events was 47.8%.
- The average response of assigned Synchronized Reserve since the implementation of the Reserve Price Formation changes on Oct. 1, 2022, excluding these Winter Storm Elliott events, is 49.8%.

Details of the reserve performance for resources assigned Synchronized Reserve can be found in **Table 8**.

Table 8. Assigned Reserve Performance

Event Date	Start (EST)	End (EST)	Synch Reserve (MW) Assignment	Synch Reserve (MW) Response (Units with assignment)	Shortfall to Assignment (MW)	Response to Assignment (%)
Dec. 23	10:14	10:25	1,791	1,547	244	86.4%
	16:17	18:09	1,846	945	901	51.2%
Dec. 24	00:05	00:30	1,767	930	837	52.6%
	02:23	02:54	1,665	535	1,130	32.1%
	04:23	05:51	1,007	169	838	16.8%

PJM has observed a drop in performance of approximately 20% for resources assigned Synchronized Reserve (excluding Winter Storm Elliott events) since the implementation of Reserve Price Formation on Oct. 1, 2022. Unrelated to the Winter Storm Elliott response, PJM has taken the following actions to address this drop in performance:

- Continued monitoring of Synchronized Reserve Performance and ACE recovery performance
- Identification of data trends including non-performance by specific resource, resource type and resource owner
- Reach out to resource owners with poor performance to identify causes of this poor performance

In addition to Synchronized Reserve response from resources assigned reserve, PJM typically observes significant response from resources that were not specifically assigned reserve at the time of the Synchronized Reserve event. While the All-Call message that announces a Synchronized Reserve Event requests all resources to load any Synchronized Reserve that they have available, resources without a Synchronized Reserve assignment at the start of the event are under no financial obligation to respond to these events and are not subject to nonresponse penalties for Synchronized Reserves. Since the implementation of Reserve Price Formation on Oct. 10, 2022, unassigned resources no longer receive a Tier 1 bonus for reserves provided.

There was also an over-response from some resources that exceeded their Synchronized Reserve assignment, although this was fairly minimal.

In the Dec. 24, 02:23 event, even with the additional contributions of reserves above assignment and from resources not assigned reserve, the total response still fell short of the system assigned reserve requirement. The response in megawatts from both units with and without Synchronized Reserve assignments are shown below in **Table 9**.

Table 9. Unit Synchronized Reserve Assignments Unit Synchronized Reserve Assignments Unit Synchronized MW Response With and Without Assignments

Event Date			Synch Reserve Assignment (MW)	Synch Reserve Unit Response (MW) With Assignment	Above Assignment	Without Assignment	Total
Dec. 23	10:14	10:25	1,791	1,547	671	2,447	4,665
	16:17	18:09	1,846	945	161	2,512	3,618
Dec. 24	00:05	00:30	1,767	930	79	1,333	2,342
	02:23	02:54	1,665	535	78	1,006	1,619
	04:23	05:51	1,007	169	7	976	1,152

As described earlier, resources that provide less Synchronized Reserve than their assignment during a Synchronized Reserve Event are required to refund Synchronized Reserve revenue in the amount of the shortfall for the durations specified above. Since the penalties are based on the SRMCP, these penalties were higher than average due to the high SRMCPs during this time. The total retroactive penalties for these five events are listed in Table 10 below.

Table 10. Total Retroactive Penalties for Five Events Dec. 23–24

Event Date	Start (EST)	End (EST)	Synch Reserve Retroactive Penalty $
Dec. 23	10:14	10:25	$8,331.65
	16:17	18:09	$55,156.22
Dec. 24	00:05	00:30	$866,580.05
	02:23	02:54	$384,402.02
	04:23	05:51	$437,698.69

PJM has identified an opportunity for PJM, in conjunction with stakeholders, to evaluate Synchronized Reserve commitment and performance. There is also an identified opportunity to discuss alignment of market incentives with operational decisions. Following the PJM stakeholder process as described in PJM Manual 34, Section 6, PJM staff will bring a Problem Statement and Issue Charge forward to begin engagement with stakeholders on these opportunities.

Cost Offer Verification

As directed by FERC Order 831, effective April 12, 2018, PJM implemented a verification process for cost-based Incremental Energy Offers above $1,000/MWh. A resource's Incremental Energy Offer must be capped at $1,000/MWh or the resource's cost-based Incremental Energy Offer, whichever is higher. Cost-based Incremental Energy Offers are capped at $2,000/MWh for the purpose of calculating LMPs. The costs underlying a cost-based Incremental Energy Offer above $1,000/MWh must be verified before it can be used to calculate LMPs.

If a resource submits an Incremental Energy Offer above $1,000/MWh, and the underlying costs cannot be verified before the market clearing process begins, the offer may not be used to calculate LMPs. In this case, the resource may be eligible for a make-whole payment if it is dispatched and its costs are verified after the fact. Likewise, a resource may also be eligible for a make-whole payment if it is dispatched and its verified cost-based Incremental Energy Offer exceeds $2,000/MWh. All resources, regardless of type, are eligible to submit cost-based Incremental Energy Offers in excess of $1,000/MWh.

PJM uses a screening process to verify the reasonableness of each generation resource's cost-based Incremental Energy Offer segment in excess of $1,000/MWh before it is considered eligible to be used in dispatch or the calculation of LMPs. This screening process is applicable to all generation resources, including those that are Fast-Start capable. Fast-Start capable resources are subjected to an additional screening process.

- Day-Ahead Market Incremental Energy Offers between $1,000/MWh and $2,000/MWh must be submitted prior to the close of the Day-Ahead Market bid period to be screened for eligibility to set LMP in the Day-Ahead Market.
- In the Real-Time Market, a resource's cost-based offer must be submitted at least 65 minutes prior to the start of the operating hour in order for the Incremental Energy Offer segments between $1,000/MWh and $2,000/MWh to be screened for eligibility to set LMP.

PJM uses published index settle prices for the commodity price and cost inputs provided by the Market Seller in the Cost Offer Assumptions (COA) module within the Member Information Reporting Application (MIRA) to calculate the Maximum Allowable Incremental Cost as outlined in the PJM Operating Agreement. Submission to COA, or other system(s) made available is considered submission to PJM and the MMU.

The Market Seller is required to provide heat inputs and performance factors in COA, or other system(s) made available for submission of such data. The heat inputs and performance factors should be provided at least one week prior to the operating day. For each Incremental Energy Offer segment greater than $1,000/MWh, PJM evaluates whether such offer segment exceeds the reasonably expected costs for that generation resource by determining the Maximum Allowable Incremental Cost for each segment in accordance with Section 6.4.3 of Schedule 1 of the PJM Operating Agreement.

- If the cost submitted for the offer segment is less than or equal to the Maximum Allowable Incremental Cost value, then that segment is deemed verified and is eligible to be used in dispatch and to set LMP.
- If the cost submitted for the offer segment is greater than the Maximum Allowable Incremental Cost value, then the cost-based offer for that segment and all segments at an equal or greater price are deemed not verified. Such segments are capped at the greater of $1,000/MWh or the price on the most expensive verified segment for the purposes of dispatch and setting LMP.

PJM notifies the Market Seller of the verification status of each segment upon completion of the screen. The Generation Resource Exception Process is presented in PJM Manual 11, Section 2.3.6.2. The process is triggered infrequently, and PJM is evaluating if there are opportunities to provide additional training on the process.

Table 11 illustrates the number of energy offers in excess of $1,000/MWh received by PJM during Winter Storm Elliott:

Table 11. Energy Offers in Excess of $1,000/MWh

	Number of units with:		
Market Day	Offers above $1,000/day	Schedule ID with offers above $1,000/Day	Exception request approved
Dec. 23	*	*	*
Dec. 24	12	16	12
Dec. 25	49	93	40
Dec. 26	19	28	17

** Due to PJM confidentiality rules, PJM is unable to disclose the counts for Dec. 23.*

All offers above $1,000/MWh received during Winter Storm Elliott were processed in advance of the Real-Time Market and were able to set LMP in real time. Some units with energy offers in excess of $1,000/MWh did set LMP with these offers.

Uplift

To incent generators and Demand Resources to operate as requested by PJM, resources that are scheduled by PJM and follow PJM dispatch instructions are guaranteed to fully recover their costs of operation. Uplift cost is created when market revenues are insufficient to cover the costs of the resources following PJM's direction.

Operating Reserve costs are payments made to economic Demand Resources and generation resources that follow PJM's direction to cover their costs and are the primary form of uplift in PJM. These payments are outside of the market and are not included in the pricing signals that are visible and transparent to Market Participants.

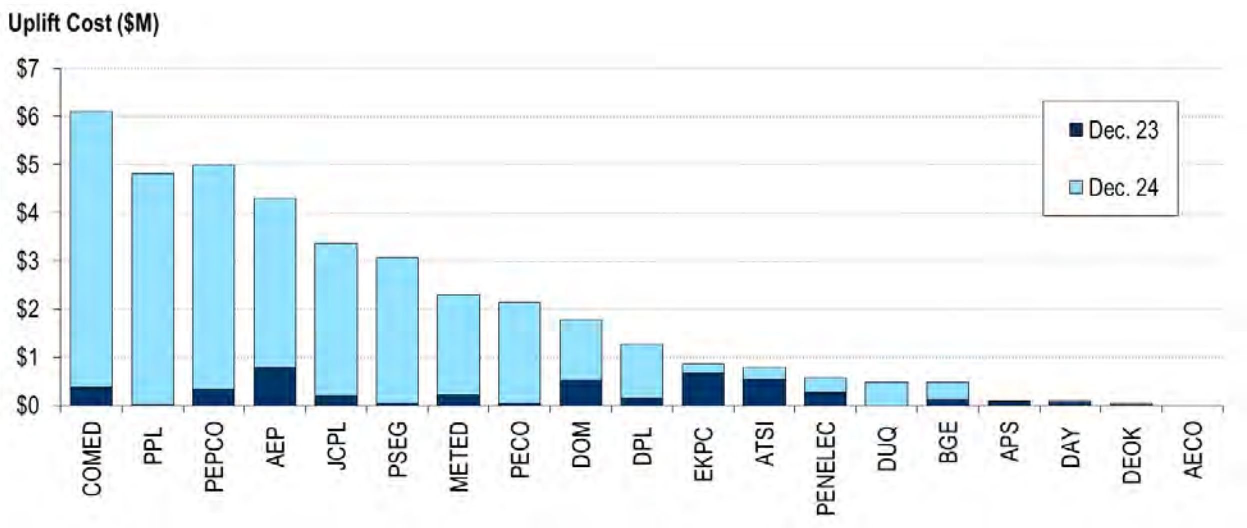
There are two reasons for out-of-market costs:

1 | Units that are running uneconomically at the direction of PJM are made whole to their offers.

2 | Units that are committed in the Day-Ahead Market and did not run in real time at PJM's direction, or had price spikes higher in real time when compared to the day-ahead lost opportunity cost, are made whole to their offers.

The Figure 85 shows the total uplift incurred by zone for Dec. 23 and Dec. 24.

Figure 85. Dec. 23 and Dec. 24 Total Uplift Incurred by Zone



A majority of the uplift cost on Dec. 23 and Dec. 24, as shown Figure 85, was due to generators scheduled by PJM running in real time to meet reliability needs.

Factors that contributed to uplift from this event include:

- Natural Gas Prices – High natural gas prices exacerbated the cost of uplift as the units operating at PJM's direction were more expensive than under more typical conditions.
- Contractual Constraints – Due to restrictions on natural gas deliveries, many resources required PJM to maintain strict megawatt output levels during periods when they were uneconomic to ensure they were

available during peak conditions. Additionally, the lack of alignment between the gas and electric day timing often required PJM to commit to running gas units prior to the Day-Ahead Energy Market.

- Prudent Operations – During Winter Storm Elliott, PJM committed resources for expected extreme system conditions. Such operations are typical during Cold Weather Alerts, resulting in the scheduling of additional reserves to account for increased forced outage rates as identified in the PJM Emergency Operations Manual. Scheduling resources in anticipation of extreme weather conditions and above-average forced outages can lower LMPs resulting in higher uplift levels.
- Interchange Volatility – Variable imports and exports of energy, which reacted to PJM energy prices, affected locational marginal prices and commitment decisions by PJM. The amount of power imported is difficult for PJM to forecast and is not completely under PJM's control; therefore, PJM must schedule internal resources to ensure that adequate generation is available given interchange uncertainty.

In the PJM market design, if a generation resource follows PJM's commitment and dispatch instructions, that generator is able to fully recover its costs for the hours it runs at PJM's direction. Operating Reserve payments are designed to incent resource owners to follow PJM direction to help maintain control of the grid in the most efficient manner possible, and also to ensure adequate operating supply plus additional capability for reserves. Day-ahead and real-time Operating Reserve credits are paid to resource owners; these credits are paid by Market Participants as Operating Reserve charges.

Increased Operating reserve costs are a side effect of running additional generation to support outages or other situations on the grid such as operational uncertainty. Uplift costs can be high when the primary fuel of additional generation being run is also high. During Winter Storm Elliott, generation was needed specifically in the northeastern region of PJM, where there is a large amount of natural gas-fired generation. Operating Reserve payments increased when the additional generation was run. Due to the tight supplies in the natural gas market, many PJM generators were kept online to mitigate the risk of being unable to obtain natural gas after shutting down. Some of these generators were run overnight because they could not shut down and restart again due to fuel or weather issues.

Market Settlement Statistics

The Day-Ahead Market allows participants to purchase and sell energy and reserves at binding day-ahead prices. Generators that are committed in the Day-Ahead Market are paid for energy based on the Day-Ahead LMP. LSEs that clear a demand bid the pay for energy based on the Day-Ahead LMP. Any quantity deviations from quantities cleared in the Day-Ahead Market are settled at the Real-Time LMP in a balancing settlement.

Units that are not committed in the Day-Ahead Market but are committed in the RAC or real-time are paid the Real-Time LMP. In the case of Dec. 23 and 24, Real-Time LMPs reached levels that were substantially higher than those in Day-Ahead. This is because the Real-Time Market is used to balance supply and demand in real time, and there is often more uncertainty about the amount of electricity that will be needed in real time. Phenomenon such as interchange volatility, load forecast uncertainty and generator trips only occur in real-time and therefore only directly influence those prices.

By understanding how balancing settlements work, generators can better manage their risks and ensure that they are adequately compensated for their output. Table 12 presents the divergence between Day-Ahead and Real-Time market prices. While this table is presented from a supply perspective, the fundamentals of the settlement apply to loads as well. That is to say that only those loads that are consuming more in real-time than they procured in the Day-Ahead Market are exposed to the high Real-Time LMPs on Dec. 23 and 24. Typically this is less than 5% of total load.

Table 12. Day-Ahead and Real-Time Market LMPs

	Day-Ahead Market		Peak LMP		Reliability Assessment Commitments (RAC) and Real-Time Commitments
	Loaded Generation (RTO Gen MW Figure 9)	Committed Generation with Outages	Day-Ahead	Real-Time	
Dec. 23	133,165 MW	12,847 MW	$224	$3,707	3,168 MW
Dec. 24	134,615 MW	16,560 MW	$259	$3,664	6,000 MW

The weekly gross billing statistics represent the total charges included in the weekly month-to-date invoices (generally spot market energy, congestion, losses and capacity charges).[11] Spot market energy, transmission congestion and transmission loss charges include positive and negative charges for supply and demand-side billing in a single charge billing line item, rather than separate charge and credit line items, as is the case with most other line items. To account for this difference, only the positive charges billed through these line items are included in the gross billing metric.

PJM's weekly invoices bill activity from the first day of the month through the end of the weekly billing period. The weekly gross billing values are calculated as the difference between the total month-to-date bill for a given week and the month-to-date bill for the prior week. For weeks with fewer than seven days, of which there was one, the gross billing was normalized to represent a seven-day week. Figure 86 presents the weekly gross billings statistics for the few weeks before and after Winter Storm Elliott.

Figure 86. Weekly Gross Billing Statistics

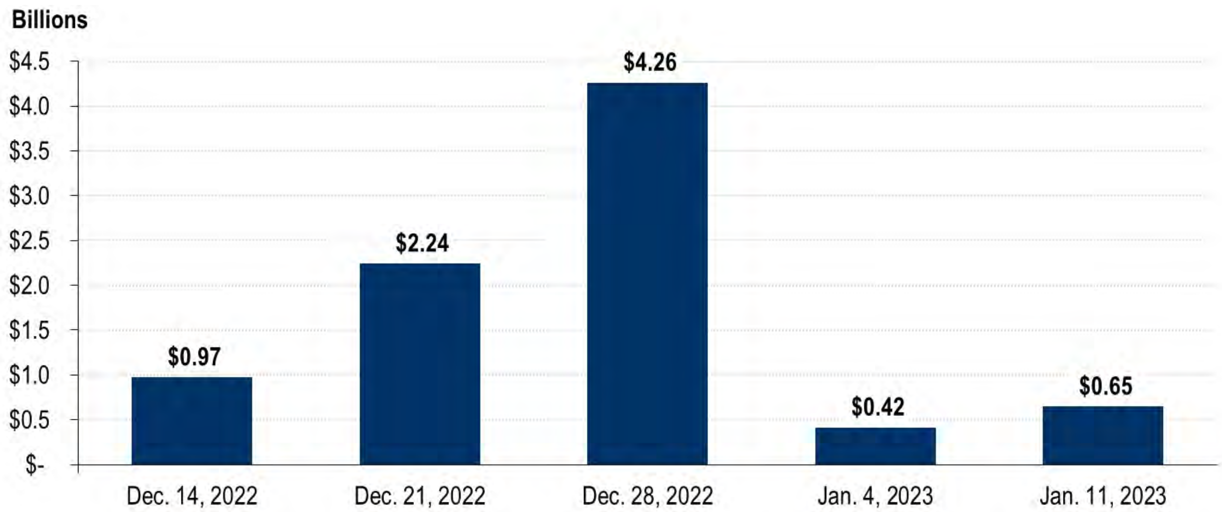
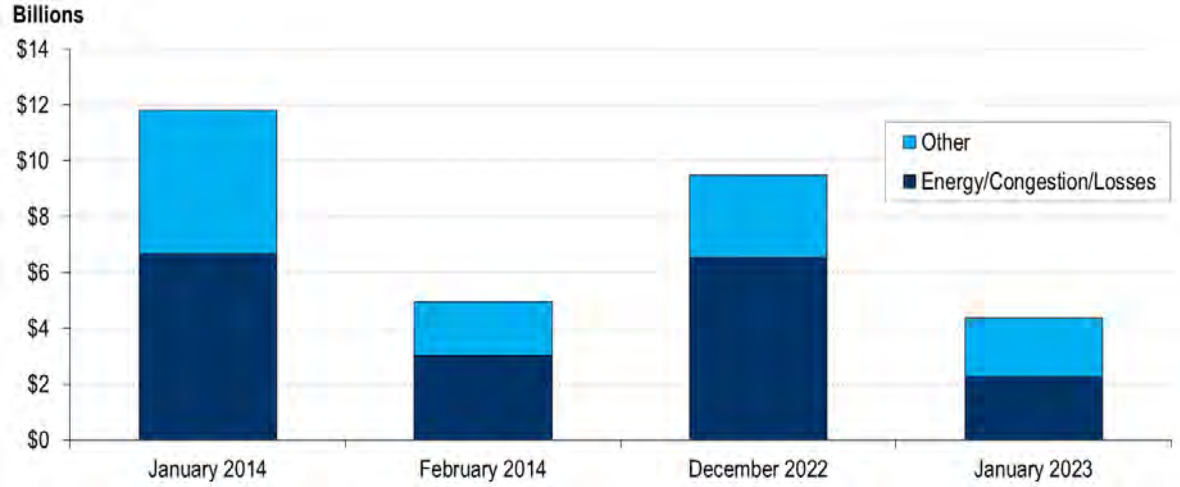


Figure 37 displays gross billing for Dec. 23 and Dec. 24, embedded in the bar chart for the week of Dec. 28. A significant increase in gross billing is observed when comparing the prior two weeks and successive two weeks to the week of Dec. 28. System conditions and operator actions reflecting the status of the RTO resulted in the higher gross billing. A contributing factor can be found in the average temperature for Dec. 23, which was 9.3 degrees Fahrenheit, with an average temperature on Dec. 24 of 7.6 degrees Fahrenheit.

Figure 87 presents the monthly gross billing comparison of Winter Storm Elliott to the 2014 Polar Vortex.

[11] PJM Manual 29, Section 3.2 details the charge line items included in the weekly invoices.

Figure 87. Winter Storm Elliott Monthly Billing vs. 2014 Polar Vortex Monthly Billing



In **Figure** 87, "Other" includes all billing except for spot market energy, congestion and transmission loss billing, including Schedule 9 and 10 charges, uplift, capacity and FTRs. As observed in the bar chart, gross monthly billing for the 2014 Polar Vortex exceeded gross monthly billing stemming from Winter Storm Elliott. A contributing factor for this difference ties to average temperatures. Average temperature for the month of January 2014 was 24.2 degrees Fahrenheit, with an average temperature of 35.4 degrees Fahrenheit for the month on December 2022.

Performance Assessment Intervals

Note: All data in this section is reflective of the performance assessment information used in the May 2023 billing statement and is being presented for informational purposes only. Nothing in this section may be construed to provide any settled expectations of charges or bonus payments. As such, to the extent adjustments are made subsequent to the May 2023 billing statement, the values herein may differ from those observed on market participants' settlement reports.

Background

The Maximum Emergency Generation Actions issued on Dec. 23 and Dec. 24, 2022, triggered Performance Assessment Intervals (PAIs) that require PJM to evaluate the performance of all resources located in the Emergency Action area for each applicable five-minute interval. The Emergency Action area for the Winter Storm Elliott performance assessment event covered the entire RTO for the intervals designated in Table 13. In total, there were 277 intervals for which performance was assessed. Given the significant number of intervals, most performance assessment data will be presented on an hourly basis (typically an average of the five-minute interval values in the hour) for purposes of this report. Other data will be looked at across the aggregate PAIs, from 17:30 EPT on Dec. 23 to 22:00 EPT on Dec. 24, or across the aggregate PAIs within a day.

Table 13. Impacted Zones for the Performance Assessment Events on Dec. 23 and Dec. 24

Location	Performance Assessment Intervals		Number of Intervals
Entire RTO	Dec. 23 17:30–23:00		66
	Dec. 24 04:25–22:00		211
	Total		277

The resources located in the RTO that were evaluated for this performance assessment event include:

- Generation: All generation resources, inclusive of Capacity Performance (CP) resources, energy-only resources and regulation-only resources
- Demand Response:
  - For Dec. 23, all pre-emergency and emergency DR (also referred to as Load Management) with 30-minute or 60-minute lead times dispatched by PJM
  - For Dec. 24, all pre-emergency and emergency DR dispatched by PJM (this includes all 30-minute, 60-minute and 120-minute lead times)
  - For both dates, some economic DR that was also dispatched or cleared in the energy and ancillary services markets
- Energy Efficiency: All annual Energy Efficiency resources
- Price-Responsive Demand: All price-responsive Demand Resources with a strike price that equaled or was lower than the five-minute LMP at their location

Based on the resource's performance and capacity commitment, resources may be assessed Non-Performance Charges or be eligible for bonus performance credits. Non-performance is determined based on the response of resources to fulfill their capacity commitments during each five-minute PAI, and no netting is permitted across intervals. Any performance shortfall or excess is calculated separately for each resource and each interval. Resources with a shortfall, or delivered energy (or reduction) less than expected based on the capacity commitment, are assessed a financial penalty. Resources demonstrating excess performance, or delivery of energy (or reduction) greater than expected based on the capacity commitment, are eligible for bonus payments.

PJM fielded many questions from Market Participants throughout and following the PAI event relating to the details of PAI business rules, penalty and bonus calculations, and Market Seller expectations during Winter Storm Elliott. This indicated the lack of widespread, detailed knowledge around the PAI process, likely due to the infrequent nature of performance assessments. It also reinforced the need to provide transparency into the PAI settlement process.[12]

PJM previously identified the following existing business rules, among others, that would benefit from more transparency, clarification or additional detail:

- Identification of assessed resources
- Calculation of real-time reserve and regulation assignment
- Calculation of scheduled megawatts for non-performance and bonus determinations

The effort to provide more transparency into the PAI settlement process started at the Market Implementation Committee and was eventually incorporated into the Resource Adequacy Senior Task Force scope. The recent requests for more

[12] Transparency Into PAI Settlements, PJM Issue Tracking, PJM.com

information into the process following Winter Storm Elliott underscore the need for this work to be addressed in the Critical Issue Fast Path – Resource Adequacy discussions.[13]

Balancing Ratio

For each PAI, PJM calculates a balancing ratio that represents the percentage share of total generation capacity commitments needed to support the load and reserves on the system within the Emergency Action area during that interval. This balancing ratio is then used to set the expected performance level of generation CP resources within the Emergency Action area for each PAI.

The balancing ratio is calculated as:

Balancing Ratio (BR) = (Total Actual Generation and Storage Performance + Net Energy Imports + DR Bonus Performance + PRD Bonus Performance) / All Generation and Storage Committed Unforced Capacity (UCAP) Commitments

Where:

- **Total actual generation and storage performance** is the actual metered output of the resources from PowerMeter, adjusted for any real-time regulation or reserves assignment.
- **Net energy imports** are the net energy import quantity during the event reported in ExSchedule, calculated as imports minus exports. This value is set to 0 for any intervals where exports exceeded imports.
- **DR bonus performance** is the net bonus megawatts for over-performing curtailment service providers (CSPs).
- **PRD bonus performance** is the net bonus megawatts for over-performing PRD resources.
- All **generation and storage-committed UCAP** are the sum of the CP commitment UCAP value for all Reliability Pricing Model (RPM) generation resources included in the assessment.

The balancing ratio is expected to align with the system demands during the Emergency Action period. The peak demand was 135,000 MW on Dec. 23 and 130,000 MW on Dec. 24. While these are high loads for the month of December, they are lower than the PJM peak load forecast that is used to establish the RPM reliability requirement (~163,000 MW). The RPM reliability requirement is established as the amount of capacity resources that are required to serve the forecast peak load and installed reserve margin to satisfy the PJM reliability criteria. As a result, it was expected that the balancing ratio would be less than 100%, because the demand during the PAIs was below the total committed capacity for those intervals. The average balancing ratio over the entire performance assessment event was 82.1%. The average balancing ratios for each day of the event are provided in **Table 14**. The balancing ratios for each five-minute interval of the event are available in Data Miner.[14]

Table 14. Summarized Balancing Ratios (BR) for Performance Assessment Intervals on Dec. 23 and Dec. 24

	Area(s)	Balancing Ratios Average	Balancing Ratios Min	Balancing Ratios Max
Dec. 23 17:30–23:00	RTO	85.48%	82.23%	88.54%
Dec. 24 04:25–22:00	RTO	81.04%	77.67%	83.96%

[13] Critical Issue Fast Path – Resource Adequacy page

[14] See PJM.com, Performance Assessment Interval Final balancing ratio.

As noted in **Real-Time Interchange**, PJM was a net exporter of energy to neighboring systems during a significant portion of the PAIs on Dec. 23 and Dec. 24, which impacts the calculation of the balancing ratio in those intervals. During those intervals when exports exceeded imports, the Net Energy Imports figure in the balancing ratio formula is floored at zero. This has the effect of setting the balancing ratio, and subsequently the expected performance levels of committed generation, at a value that reflects both needs of the PJM system plus the assistance provided to neighboring systems in that interval. This result, of setting the balancing ratio and expected performance of committed generation capacity at a level beyond what's needed to satisfy PJM's system demand, warrants further consideration and discussion on the treatment of exports and imports in the balancing ratio and the level to which committed generation capacity should be held accountable during PAIs.

Performance Shortfall

Non-performance is measured by comparing a resource's actual performance to their expected performance to calculate a performance shortfall. This performance shortfall represents the amount of the committed capacity from the resource that was needed during the event but was not delivered to the system. The performance shortfall is calculated as: expected performance minus actual performance.

The expected performance of a resource is its CP commitment, adjusted by the balancing ratio (for generation) to account for the megawatts needed during the PAI. The actual performance of a resource is defined as the output of the resource during the event, accounting for both energy and ancillary services. The energy output is measured by the metered output (or load reduction) of the resource. The ancillary services portion of actual performance is based on the real-time regulation, Synchronized Reserves, Non-Synchronized Reserves or Secondary Reserves on the resource. The calculation for the ancillary service adjustment captures any movement off of the economic basepoint for the resource to provide the service in real time, so that the actual performance calculation credits the resource for any energy megawatts they did not produce in order to provide an ancillary service assignment.

The expected and actual performance calculations for CP resources are based on resource type:

- Generation/Storage:
  - Expected Performance = Capacity Commitment (UCAP) x Balancing Ratio
  - Actual Performance = Metered Energy Output + Reserve/Regulation Adjustment[15]
- Demand Response:
  - Expected Performance = CP Capacity Commitment (ICAP)[16]
  - Actual Performance = Load Reduction + Reserve/Regulation Adjustment[5]
- Price Responsive Demand
  - Expected Performance = CP Capacity Commitment (ICAP)

[15] For calculations for reserve and regulation assignment megawatts factored into actual performance, see the Performance Assessment Settlement Summary on PJM.com.

[16] Capacity Performance Demand Resources are only required to interrupt their load between the hours of 6:00 through 21:00 EPT for the months of November through April. As such, even though the emergency and pre-emergency load management reduction actions on the Dec. 23 did not end until 21:30 and 22:15, respectively, Capacity Performance Demand Resources were not required to curtail consumption beyond 21:00. Expected Performance is 0 MW outside the required hours of curtailment.

- Actual Performance = Load Reduction

- Energy Efficiency:
  - Expected Performance = CP Capacity Commitment (ICAP)
  - Actual Performance = PJM-Approved Post-Installation Load Reduction

If a resource's expected performance is greater than the actual performance, the resource will be assessed a non-performance penalty, unless the shortfall is excused from the performance shortfall. The reasons for excusal and the megawatts that were excused for the Winter Storm Elliott performance assessment event are discussed in the Excusal section of this paper.

The average initial shortfall across the performance assessment event, prior to excusals, was 38,068 MW. The hourly average data for the expected, actual and shortfall megawatts can be found in Table 15. Notably, actual performance across all resources in the Emergency Action area exceeds expected performance for each five-minute interval, which at first glance seems somewhat contrary to the presence of an initial shortfall. However, this is explained by performance from resources that did not have a performance obligation at the time of the performance assessment event, as well as over-performance by some resources that did have a CP obligation.

Due to the number of CP resources that exceeded the expected performance, energy-only resources that were online and generating, and net energy imports flowing into the RTO during the performance assessment event, the aggregate actual performance in all intervals was greater than the expected performance, resulting in bonus megawatts for each interval of this event.

Table 15. Aggregate Expected, Actual and Initial Shortfall Performance (hourly avg. of five-minute interval totals)

Hour Beginning (EPT)		AVERAGE		
		Expected MW Per Interval	Actual MW Per Interval	Initial Shortfall MW Per Interval
Dec. 23, 2022	17:00	142,502	144,350	35,861
	18:00	147,697	149,537	36,446
	19:00	147,850	149,788	36,566
	20:00	148,011	149,936	36,924
	21:00	147,359	149,726	37,719
	22:00	139,231	141,239	36,559
Dec. 24, 2022	04:00	131,369	133,283	39,552
	05:00	131,661	133,557	39,666
	06:00	141,681	142,127	41,179
	07:00	146,004	145,228	40,926
	08:00	147,220	147,511	39,435
	09:00	146,875	148,993	38,452
	10:00	145,829	147,957	39,210
	11:00	145,045	147,264	39,611
	12:00	144,689	146,911	39,036
	13:00	143,037	145,269	38,164
	14:00	140,860	142,988	38,448
	15:00	141,807	143,929	38,587

Hour Beginning (EPT)	AVERAGE		
	Expected MW Per Interval	Actual MW Per Interval	Initial Shortfall MW Per Interval
16:00	144,464	146,607	38,653
17:00	145,637	147,793	37,650
18:00	145,211	147,327	36,820
19:00	142,313	144,420	36,317
20:00	134,636	136,550	34,505
21:00	132,933	134,927	34,744

Although actual performance exceeded expected performance in aggregate for each interval, non-performance is assessed on an individual resource basis. Therefore, shortfall megawatts and associated Non-Performance Charges were assessed to resources in each of these intervals if their individual resource performance fell short of the expected megawatts. Breaking out the shortfall megawatts to a more granular level, the next few graphs and charts contain only the CP resources that had an initial shortfall. CP resources that have met or exceeded their expected performance, and energy-only resources, are excluded from these data sets. In aggregate, resources with shortfall megawatts provided 27% of their expected megawatts during the event. This aggregate performance was weighed down by the number of capacity resources on full or partial forced outages during the event.

Table 16. Expected, Actual and Initial Shortfall Performance for Under Performing Resources (hourly average of five-minute interval totals)

Hour Beginning (EPT)		AVERAGE Expected MW per Interval	Actual MW per Interval	Initial Shortfall MW per Interval
Dec. 23, 2022	17:00	46,052	10,192	35,861
	18:00	49,254	12,808	36,446
	19:00	48,287	11,722	36,566
	20:00	47,773	10,849	36,924
	21:00	49,873	12,154	37,719
	22:00	47,221	10,662	36,559
Dec. 24, 2022	4:00	50,346	10,793	39,552
	5:00	50,340	10,674	39,666
	6:00	54,181	13,002	41,179
	7:00	54,893	13,967	40,926
	8:00	52,794	13,359	39,435
	9:00	51,993	13,540	38,452
	10:00	52,162	12,952	39,210
	11:00	52,497	12,886	39,611
	12:00	52,563	13,528	39,036
	13:00	54,373	16,209	38,164
	14:00	56,301	17,853	38,448
	15:00	54,230	15,643	38,587
	16:00	52,981	14,328	38,653
	17:00	53,101	15,451	37,650
	18:00	55,288	18,468	36,820
	19:00	54,934	18,616	36,317
	20:00	53,868	19,363	34,505
	21:00	52,893	18,149	34,744

Excusals

A resource's performance shortfall is evaluated for excusals and may be adjusted downward if the shortfall is deemed to be exempt. Megawatts are excused from performance if they were solely unavailable for the following reasons:

- Megawatts were on a PJM-approved planned or maintenance outage.
- Megawatts were not scheduled to operate by PJM, or were scheduled down by PJM, in alignment with the dispatch run LMP resulting from the Security Constrained Economic Dispatch and/or reliability needs.

However, if a resource was needed by PJM and would otherwise have been scheduled by PJM to perform, but was not scheduled to operate, or was scheduled down solely due to: (1) any operating parameter limitations submitted in the resource's offer, or (2) submission of market-based offer higher than cost-based offer, then these megawatts are not excused and will not result in downward adjustment of performance shortfall.

For the Winter Storm Elliott event, the average excused megawatts deemed unavailable solely due to approved maintenance and planned outages were approximately 3,800 MW. The maintenance and planned outages are in line with what can be expected in a typical winter or summer season. These outages are scheduled and approved by PJM and recallable 72 hours in advance. This is the reason these megawatts are deemed to be exempt from performance during their approved outage period. Prior to Dec. 23, PJM did not recall any generation maintenance outages, as load projections did not indicate that would be necessary. Forced outages, or outages that are unscheduled or unplanned, are not exempt from performance requirements; resources on a forced outage with a performance shortfall are assessed Non-Performance Charges.

Megawatts that were not supported by LMP, or were otherwise scheduled down by PJM, are exempt from performance penalties, because their megawatts were not needed to support the system or production of those megawatts when unneeded could have been detrimental to system reliability. It is important to system reliability during a performance assessment event that resources continue to follow PJM direction to help maintain power balance. Resources may not be scheduled by PJM due to economic reasons, such as projected system conditions and locational marginal prices (LMPs) that did not support bringing the resource online; or controlling transmission constraints that supported lowering the unit's output; or the resource is held offline or down by PJM for reserves.

Some instances of PJM manual dispatch instruction or units that were not scheduled required extensive case-by-case review by PJM staff including the review of operator logs, market data, outage data and operator conversations to determine the required level of excusal or bonus.

A more granular breakdown of the excused megawatts for each hour of the event, and the resulting final shortfall, is included in Table 17. This includes shortfalls from generation, Demand Response and Price Responsive Demand resources. Energy Efficiency resources are excluded solely because they did not have any performance shortfalls for this event. As discussed further in the

Netting for Demand Response and Price Responsive Demand section of this paper, while Demand Response and Price Responsive Demand Resources are not eligible for excusals in the same manner as generation resources, their performance shortfalls can be offset by over-performance of other resources. Any shortfall megawatts that were offset by over-performance from other resources have been included in the Average Not Scheduled column in the table below to facilitate complete accounting of final shortfall megawatts across the fleet of capacity resources. [17]

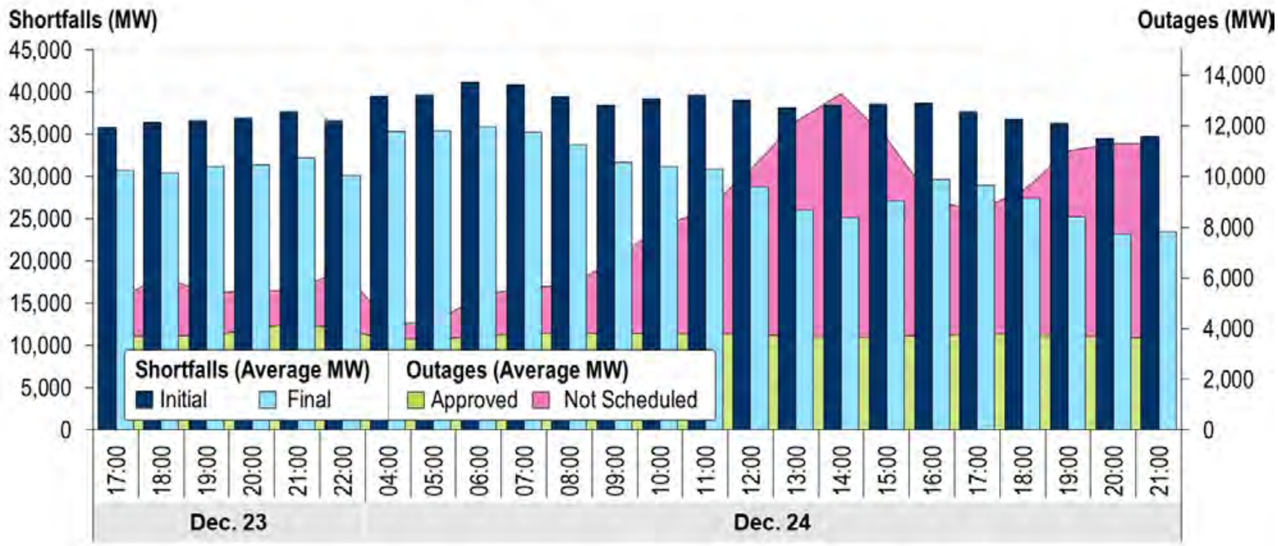
[17] The average DR and PRD shortfall megawatts offset by over-performance by other resources is 230 MW per interval.

Table 17. Initial Shortfall, Excused MW and Final Shortfall (hourly average of five-minute interval totals)

Hour Beginning (EPT)		AVERAGE Initial Shortfall (MW)	Approved Outages (MW)	Not Scheduled (MW)	Final Shortfall (MW)
Dec. 23, 2022	17:00	35,861	3,674	1,469	30,718
	18:00	36,445	3,709	2,351	30,385
	19:00	36,566	3,700	1,694	31,172
	20:00	36,924	3,989	1,505	31,430
	21:00	37,719	4,238	1,262	32,219
	22:00	36,559	3,977	2,418	30,164
Dec. 24, 2022	04:00	39,552	3,581	658	35,313
	05:00	39,666	3,589	642	35,435
	06:00	41,179	3,700	1,572	35,907
	07:00	40,926	3,791	1,860	35,275
	08:00	39,435	3,827	1,826	33,782
	09:00	38,452	3,820	2,887	31,745
	10:00	39,210	3,791	4,219	31,200
	11:00	39,610	3,769	4,902	30,939
	12:00	39,034	3,759	6,528	28,747
	13:00	38,164	3,710	8,441	26,013
	14:00	38,448	3,645	9,634	25,169
	15:00	38,587	3,673	7,852	27,062
	16:00	38,652	3,751	5,305	29,596
	17:00	37,649	3,786	4,885	28,978
	18:00	36,797	3,773	5,644	27,380
	19:00	36,285	3,733	7,277	25,275
	20:00	34,505	3,657	7,640	23,208
	21:00	34,744	3,634	7,645	23,465

The average total excused megawatts in each PAI on Dec. 23 was approximately 5,600 MW per interval. The average for Dec. 24 was higher, at approximately 8,700 MW per interval. Figure 88 shows that planned outages were consistent across all intervals of the event, and that the increase in excusals on Dec. 24 was driven by higher levels of excusals for megawatts not scheduled on Dec. 24 as strain on the system eased throughout the day.

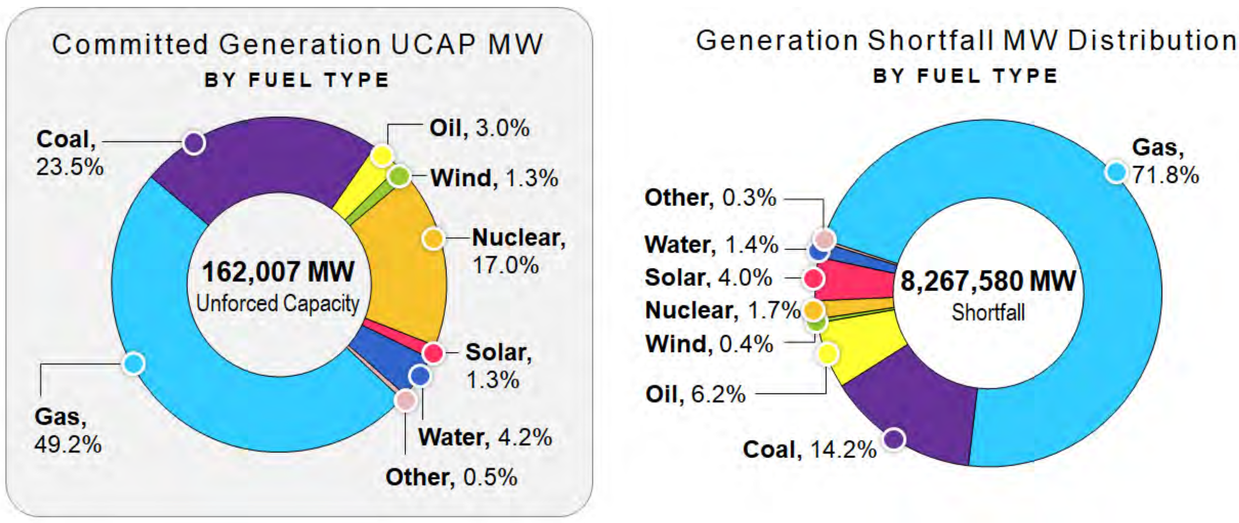
Figure 88. Excusal Megawatts and Final Shortfall MW (hourly average of five-minute interval values)



Generation Shortfall Distribution by Fuel Type

Figure 89 depicts how the final shortfall megawatts for generation resources were distributed across the generation fleet using primary fuel type. Also provided in this figure is the distribution of committed generation capacity megawatts by primary fuel type to assist in understanding how proportionate the shortfall megawatts by fuel type are to that fuel type's share of total committed generation capacity. For example, while gas units make up roughly half of committed generation capacity, they represented 71.8% of all shortfall megawatts, which tracks with the observations in the Operating Day section of this report that gas resources represented the majority of the forced outages during Winter Storm Elliott for the reasons explained therein. Solar resources also had an outsized proportion of the shortfall megawatts compared to their share of committed capacity. This is attributed to the timing of the performance assessment intervals, the majority of which occurred during hours with low levels of solar irradiance. Conversely, wind resources represented an undersized share of the performance shortfall, which tracks their strong performance noted in the Positive Observations section of this paper. The high availability factor of nuclear resources during Winter Storm Elliott resulted in the strong performance of nuclear resources and their undersized share of the shortfall megawatts.

Figure 89. Generation Shortfall MW Distribution by Fuel Type compared to Capacity Commitment



Netting for Demand Response and Price Responsive Demand

Performance shortfalls for Demand Resources deployed during a performance assessment event are evaluated as a group with all other Demand Resources in the same Emergency Action area belonging to the curtailment service provider (CSP) that committed the resource to the capacity market. For the Winter Storm Elliott event, the Emergency Action area encompassed the entire RTO, resulting in initial performance shortfall (positive or negative) of all resources belonging to the CSP being netted to determine a net performance shortfall.

In this manner, over-performance on some resources within a CSP's portfolio is able to offset under-performance on other resources in the same interval. If a CSP has a net positive shortfall of megawatts once the performance of all of its Demand Resources are netted together, the resulting shortfall is allocated to Demand Resources that under-performed pro-rata using their under-compliance megawatts. Based on this netting, a Demand Resource's final shortfall megawatts will be less than its initial shortfall megawatts if other Demand Resources in the portfolio over-performed for the same interval and were able to offset some of its shortfall.

Performance shortfalls for Price Responsive Demand (PRD) resources deployed during a performance assessment event are also evaluated as a group with all other PRD resources belonging to the provider that committed the resource to the capacity market, similar to the netting that occurs for Demand Resources.

The initial and final shortfall megawatts for Demand Resources and PRD resources during this performance assessment event are shown in Table 18. The difference between the initial and final shortfall values is reflective of the DR or PRD over-performance megawatts that was able to offset any performance shortfalls. Megawatts of over-performance that are used to net against under-performance of other resources are not eligible to receive bonus credits. The Demand Response and PRD performance values have been aggregated in the table below to adhere to posting rules around market-sensitive data given the small number of Market Participants with PRD resources.[18] For some hours, the number of combined DR and PRD Market Participants with shortfalls still does not meet the requirements for posting market-sensitive data. The data for those hours has been omitted and marked with **.

[18] PJM Manual 33, Section 6.1

Table 18. DR and PRD Initial and Final Shortfall (hourly average of 5-minute interval values)

Hour Beginning (EPT)		Average DR & PRD Initial Shortfall	Average DR & PRD Final Shortfall
Dec. 23, 2022	17:00	**	**
	18:00	583.8	267.4
	19:00	519.3	197.8
	20:00	526.4	213.7
	21:00	**	**
	22:00	0	0
Dec. 24, 2022	04:00	**	**
	05:00	**	**
	06:00	312.7	14.3
	07:00	528.3	126.3
	08:00	521.5	116.4
	09:00	433.5	38.4
	10:00	382.8	21.6
	11:00	365.3	20.8
	12:00	359.1	22.1
	13:00	337	16.3
	14:00	316.6	15.5
	15:00	315.8	14.8
	16:00	337.7	14.5
	17:00	371.6	16.2
	18:00	357.1	14.9
	19:00	88.6	11.4
	20:00	**	**
	21:00	0	0

Non-Performance Charges

Non-Performance Charge rates are calculated on a modeled RPM Locational Deliverability Area (LDA) basis for the relevant delivery year. The Non-Performance Charge rate for a specific resource is based on the Net Cost of New Entry (Net CONE) ($/MW-day in installed capacity terms) for the LDA in which such resource resides and is calculated as:

Non-Performance Charge Rate ($/MW-5-Minute Interval) =
Net CONE x Number of Days in Delivery Year / 30 Hours / 12 Intervals

The applicable charge rates for the Winter Storm Elliott PAIs for the 2022/2023 Delivery Year are detailed in Table 19.[19]

Table 19. Non-Performance Charge Rates by LDA ($/MW-5-Minute Interval)

Non-Performance Charge Rates by Locational Deliverability Area (LDA)					
ATSI	221.83	DPL-SOUTH	227.29	PS-NORTH	258.34
ATSI-CLEVELAND	221.83	EMAAC	249.60	PSEG	258.34
BGE	217.85	MAAC	235.90	RTO	250.69
COMED	238.54	PEPCO	249.76	SWMAAC	233.81
DAY	217.8	PPL	240.99		
DEOK	215.22				

These charge rates are multiplied by the final performance shortfall in each five-minute interval to determine the non-performance financial penalty for committed capacity resources. The Non-Performance Charge is calculated as:

*Non-Performance Charge = Performance Shortfall MW * Non-Performance Charge Rate*

The Non-Performance Charge for the performance assessment event totals approximately $1.80 billion, which was allocated across roughly 750 resources with final performance shortfall megawatts.

This represents 45% of the $3.97 billion in RPM auction credits paid across all committed capacity resources for the 2022/2023 Delivery Year. When isolating only the resources with shortfalls, the $1.80 billion in Non-Performance Charges represents 83% of the $2.17 billion in RPM auction credits collectively received by these under-performing resources for the 2022/2023 Delivery Year.

The hourly average and total Non-Performance Charges by hour are listed in Table 20.

[19] Modeled LDA Net CONE values for the 2022/2023 Delivery Year are available on PJM.com.

Table 20. Non-Performance Charges by Hour

Hour Beginning (EPT)		Non-Performance Charges ($) Average of Interval-Level	Total Hourly
Dec. 23, 2022	17:00	6,589,973.18	39,539,839.05
	18:00	6,505,727.97	78,068,735.58
	19:00	6,731,000.98	80,772,011.71
	20:00	6,827,351.73	81,928,220.72
	21:00	7,031,512.93	84,378,155.18
	22:00	6,532,125.94	78,385,511.32
Dec. 24, 2022	04:00	7,785,599.61	54,499,197.25
	05:00	7,799,035.09	93,588,421.11
	06:00	7,733,603.22	92,803,238.65
	07:00	7,768,289.54	93,219,474.49
	08:00	7,473,896.14	89,686,753.62
	09:00	7,034,963.27	84,419,559.27
	10:00	6,910,820.64	82,929,847.71
	11:00	6,858,699.63	82,304,395.52
	12:00	6,370,314.53	76,443,774.40
	13:00	5,704,554.02	68,454,648.19
	14:00	5,508,448.92	66,101,387.04
	15:00	5,831,635.11	69,979,621.27
	16:00	6,365,883.24	76,390,598.86
	17:00	6,103,588.46	73,243,061.57
	18:00	5,739,415.91	68,872,990.94
	19:00	5,314,600.31	63,775,203.73
	20:00	4,951,402.92	59,416,835.04
	21:00	5,033,588.91	60,403,066.98
			$1,799,604,549.20

Stop-loss provisions are in place to limit the total Non-Performance Charge that can be assessed on each capacity resource. For CP resources, the maximum yearly Non-Performance Charge is 1.5 times the modeled LDA Net CONE ($/MW-day in installed capacity terms), times the number of days in the delivery year, times the maximum daily unforced capacity committed by the resource from June 1 of the delivery year through the end of the month for which the Non-Performance Charge was assessed. For all CP resources involved in the Winter Storm Elliott performance assessment event, the calculated Non-Performance Charge for the event was below the maximum yearly Non-Performance Charge. Further, for those Demand Response resources that were also subject to the performance assessment event in June 2022 earlier that same delivery year, the cumulative Non-Performance Charge for the delivery year did not exceed the maximum yearly Non-Performance Charge. As a result, it was not necessary to apply the stop-loss provision to any CP resource for the Winter Storm Elliott performance assessment event.

A resource that does not have enough unforced capacity value to cover the RPM commitment on the resource is subject to a Daily Capacity Resource Deficiency Charge. The Daily Capacity Resource Deficiency Charge is equal to the Daily

Deficiency Rate times the Daily RPM Commitment Shortage for generation resource, Demand Resource or Energy Efficiency Resource.[20]

Resources with Daily Capacity Resource Deficiency Charges may also have Non-Performance Charges during a non-performance event. In this case, a cap is placed on the total amount of deficiency-related charges a resource can be assessed. A resource that is subject to a Non-Performance Charge during one or more intervals occurring during a continuous time period of Daily RPM Commitment Shortages is assessed a charge equal to the greater of: a) the total Daily Capacity Resource Deficiency Charges calculated for shortages associated with Capacity Performance commitments for such continuous time period, or b) the total Non-Performance Charges calculated for the Performance Assessment Intervals occurring during such continuous time period.

The sum of the Daily Capacity Resource Deficiency Charges and Non-Performance Charges actually billed for such continuous time period may not exceed the resultant greater of charge. For the Winter Storm Elliott event, approximately $815,000 in Non-Performance Charges were excluded from the performance assessment billing based on this cap on total deficiency-related charges assessed to deficient resources. This $815,000 is not reflected in the values in Table 20.

Fixed Resource Requirement Shortfall Megawatts and Non-Performance Penalties

Resources that have been committed to a Fixed Resource Requirement (FRR) plan have the same obligation to perform during a performance assessment event as resources with RPM capacity commitments.

Shortfall megawatts from resources committed to FRR plans were included in the above tables summarizing resource performance and Non-Performance Charges, where applicable. Market Participants meeting their capacity obligations through FRR plans have the additional option to elect the physical non-performance assessment option.[21]

Entities that elect the FRR physical option are not assessed Non-Performance Charges and are not eligible for bonus performance credits for any performance associated with their FRR commitments. Instead, these entities must commit an additional megawatt quantity to their FRR capacity plan for the next delivery year in an amount equal to the sum of the net positive shortfalls for resources committed to their FRR plan across all five-minute intervals in the performance assessment event, multiplied by the FRR physical penalty rate.

The physical penalty rate is 0.00139 MW / Performance Assessment Interval [i.e., 0.5 MW / 30 PAHs / 12 intervals per hour]. For example, a resource with 1,000 MW of shortfall summed across all five-minute intervals in the performance assessment event would need to commit an additional 1.4 MW of capacity to their FRR plan for the delivery year following the event. In contrast, if the FRR entity for this resource instead chose the financial non-performance assessment option and was subject to the RTO Non-Performance Charge rate of $250.69/MW per five-minute interval, the resource would be assessed a charge of $250,690.

PJM is unable to report on the breakout of FRR Market Participants that have elected the physical non-performance assessment option vs. the financial non-performance assessment option or the penalties assessed to resources within their plans due to the small number of Market Participants utilizing FRR plans and requirements for posting market-sensitive data.[22]

Bonus Performance

A resource with actual performance above its expected performance is considered to have provided bonus performance, and will be assigned a share of the collected Non-Performance Charge revenues in the form of a bonus performance

[20] See PJM Manual 18, Section 9.1.3 for more information about Daily Capacity Resource Deficiency Charges.
[21] Refer to PJM Manual 11, Section 11.8.7 Physical Non-Performance Assessment.
[22] PJM Manual 33, Section 6.1

credit. Bonus performance from a resource represents greater delivered energy (or reductions), in comparison to the amount of the committed capacity from the resource that was needed during the event. Bonus performance is calculated on all over-performing resources as actual performance minus expected performance.

The expected and actual performance calculations for bonus megawatt evaluations are based on resource type:

- Generation/Storage:
  - Expected Performance = CP Commitment (UCAP) x Balancing Ratio
  - Actual Performance = Metered Energy Output + Reserve/Regulation Adjustment[23]
- Demand Response:
  - Expected Performance = CP Capacity Commitment (ICAP)
  - Actual Performance = Load Reduction + Reserve/Regulation Adjustment
- Energy Efficiency:
  - Expected Performance = CP Capacity Commitment (ICAP)
  - Actual Performance = PJM Approved Post-Installation Load Reduction
- Price Responsive Demand
  - Expected Performance = CP Capacity Commitment (ICAP)
  - Actual Performance = Load Reduction
- Net Imports
  - Expected Performance = 0 MW
  - Actual Performance = Sum (Import MW) – Sum (Export MW)

When calculating bonus megawatts, the actual performance for a generation resource is capped at the megawatt level at which such resource was scheduled and dispatched by PJM during the performance assessment event. PJM caps the megawatt level that a resource is eligible to receive bonus credit for to incent resources to follow dispatch in real time to support operations, and not chase potential bonus credits by over-generating. Resources must also have at least one available schedule with an economic minimum, economic maximum and emergency maximum, and at least one segment on the incremental energy offer curve so that PJM can determine the scheduled megawatts used in the determination of the cap. [24]

On average, approximately 2,700 MWh of energy in excess of expected megawatts was not eligible for bonus credits in each interval due to capping or failure to meet the energy offer requirements. PJM observed that a subset of these ineligible megawatts were from renewable resources that provided energy in excess of their expected megawatts. Many of these resources do not submit fuel cost policies and by default agree to be dispatched as a zero-cost resource in the

[23] The reserve/regulation adjustment made for actual performance for bonus purposes is the same as the adjustment made for shortfall calculation purposes. For calculations for reserve and regulation assignment megawatts factored into actual performance, see the Performance Assessment Settlement Summary.
[24] This rule is defined in Manual 11, Section 2.3.7.

absence of an approved fuel-cost policy. As such, these resources did not enter any segments on their Incremental Energy Offer curve and were therefore excluded from bonus payments.

The average bonus megawatts eligible for bonus credits for the Winter Storm Elliott performance assessment event was 34,318 MW per interval. On average, approximately 70% of these megawatts came from CP resources, while 30% came from energy-only resources (including net energy imports). The larger percent of bonus megawatts from the CP resources are driven by those resources being online and generating, and the average 82.1% balancing ratio. On average, resource output in excess of 82.1% of their capacity commitment, up to the megawatt level at which the resource was scheduled and dispatched, can be attributed to over-performance.

Table 21. Bonus Performance Megawatts by Hour by CP Resources and Energy Resources (hourly average of five-minute interval values)

Hour Beginning (EPT)		Average Bonus MW: CP Resources	Average Bonus MW: Energy Resources	Average Total Bonus MW
Dec. 23, 2022	17:00	22,988.9	10,128.8	33,117.7
	18:00	23,102.9	10,827.0	33,930.0
	19:00	23,342.9	10,555.7	33,898.6
	20:00	23,825.6	10,312.1	34,137.8
	21:00	25,530.0	10,228.4	35,758.4
	22:00	23,059.9	10,717.0	33,776.9
Dec. 24, 2022	04:00	25,566.7	11,408.0	36,974.8
	05:00	25,850.1	10,984.0	36,834.1
	06:00	25,966.6	10,927.8	36,894.4
	07:00	24,469.0	11,490.8	35,959.9
	08:00	24,406.5	10,500.8	34,907.3
	09:00	25,106.4	9,974.4	35,080.8
	10:00	25,818.1	10,900.9	36,719.1
	11:00	26,328.8	10,850.1	37,178.9
	12:00	25,020.0	10,390.9	35,410.9
	13:00	22,903.1	10,435.4	33,338.6
	14:00	22,955.3	10,782.6	33,737.9
	15:00	24,371.7	10,314.0	34,685.8
	16:00	25,360.7	9,607.9	34,968.7
	17:00	23,723.6	9,569.2	33,292.8
	18:00	21,557.6	10,219.8	31,777.4
	19:00	21,716.6	9,978.6	31,695.2
	20:00	19,887.0	9,678.5	29,565.6
	21:00	21,310.7	8,681.8	29,992.6

Table 21 breaks out the average total bonus megawatts by resource type. On average, 80% of bonus megawatts were produced by generation, 10% came from net import transactions, 5% were produced by Energy Efficiency resources, and 5% were produced by Demand Response and PRD resources.

Energy Efficiency bonus megawatts are a static 1,720.9 MW across each five-minute interval of the entire performance assessment event. Actual performance for Energy Efficiency resources is established by the average demand reduction reported in the last post-installation measurement and verification report submitted by the Market Seller and approved by PJM prior to the delivery year in question.[25] Energy Efficiency resources automatically receive bonus megawatts for demand reduction in excess of their capacity commitment, as demonstrated in the post-installation measurement and verification report when a Capacity Performance event occurs.

The Demand Response and PRD bonus megawatt values include pre-emergency and emergency load management resources as well as economic Demand Resources cleared for energy or ancillary services. Pre-Emergency and Emergency Load Response resources are only required to interrupt their load between the hours of 06:00 through 21:00 EPT for the months of November through April. As such, even though the emergency and pre-emergency load management reduction actions on Dec. 23 did not end until 21:30 and 22:15, respectively, Capacity Performance Demand Resources were not required to curtail consumption beyond 21:00. The expected megawatts from these resources in the hours outside their mandatory curtailment period is 0 MW. One-hundred percent of the load reductions from pre-emergency and emergency load management resources in such hours are therefore counted as bonus megawatts. This is the reason the Average DR and PRD bonus megawatts for hour beginning 22:00 jumps five-fold from the previous hour.

Table 22. Bonus Performance Megawatts Broken Down by Resource Type (hourly average of five-minute interval values)

Hour (EPT Hour Beginning)		Average Bonus MW			
		Generation	Net Imports	EE	DR & PRD
Dec. 23, 2022	17:00	28,350.9	2,849.5	1,720.9	196.40
	18:00	27,965.0	3,490.5	1,720.9	753.50
	19:00	28,023.9	3,243.0	1,720.9	910.70
	20:00	28,410.3	3,032.2	1,720.9	974.20
	21:00	25,926.2	3,158.3	1,720.9	4,952.90
	22:00	27,974.1	3,834.8	1,720.9	247.00
Dec. 24, 2022	04:00	30,731.4	4,392.8	1,720.9	129.50
	05:00	31,103.6	3,897.8	1,720.9	111.70
	06:00	29,108.1	3,953.5	1,720.9	2,111.80
	07:00	28,213.2	4,289.4	1,720.9	1,736.30
	08:00	27,811.6	3,601.9	1,720.9	1,772.90
	09:00	28,422.5	3,084.0	1,720.9	1,853.30
	10:00	29,135.8	3,953.2	1,720.9	1,909.00
	11:00	29,514.4	3,849.5	1,720.9	2,094.10
	12:00	27,890.1	3,631.0	1,720.9	2,168.90
	13:00	25,798.2	3,603.0	1,720.9	2,216.40
	14:00	25,767.6	3,980.7	1,720.9	2,268.60
	15:00	27,083.5	3,610.1	1,720.9	2,271.20
	16:00	27,785.5	3,287.5	1,720.9	2,174.70
	17:00	26,248.9	3,254.7	1,720.9	2,068.20

[25] See PJM Manual 18, Section 4.4.1: Determination of Nominated value of EE Resources for more detail on how the average demand reduction upon which actual performance for Energy Efficiency resources is established.

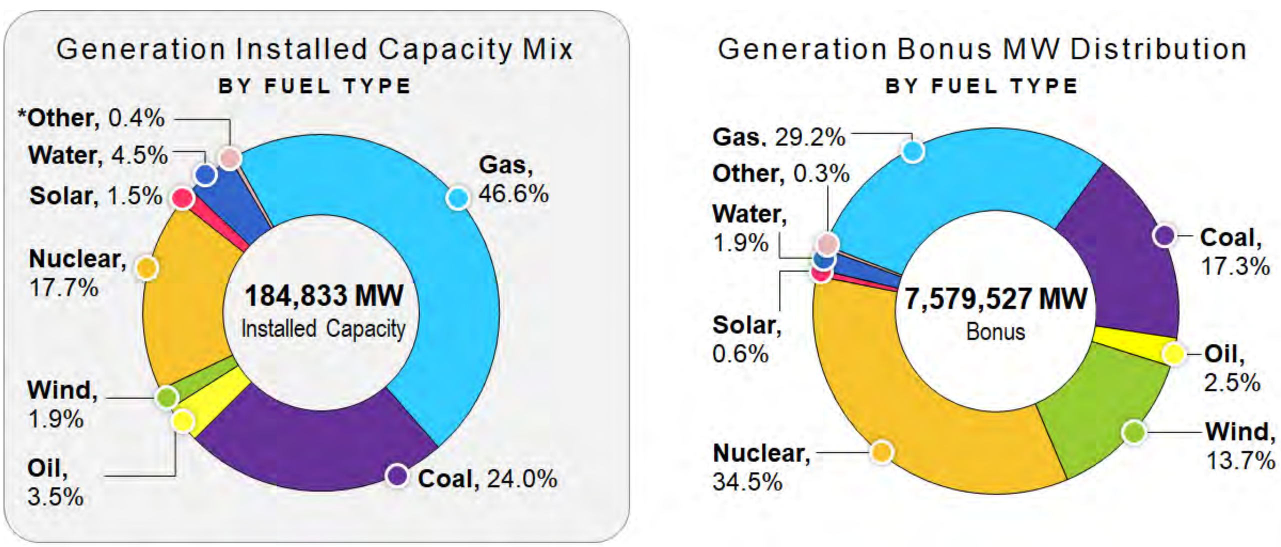
Hour (EPT Hour Beginning)		Average Bonus MW: Generation	Net Imports	EE	DR & PRD
	18:00	24,265.0	3,670.7	1,720.9	2,120.80
	19:00	23,588.6	3,549.7	1,720.9	2,835.90
	20:00	23,533.7	3,461.0	1,720.9	849.90
	21:00	25,954.5	2,280.0	1,720.9	37.10

Generation Bonus Performance Distribution by Fuel Type

Figure 90 depicts how the bonus performance megawatts from generation resources was distributed across the generation fleet using primary fuel type. Also provided in this figure is the installed capacity mix of the PJM generation fleet by primary fuel type to assist in understanding how proportionate the bonus performance by fuel type is to that fuel type's share of total generation capability. Consistent with their undersized portion of the shortfall megawatt pool, nuclear and wind resources in particular had outsized shares of the bonus performance pool given their strong performance during Winter Storm Elliott. Nuclear resources represented the largest share of bonus performance megawatts at 34.5%, or roughly double their share of the installed capacity mix. This stems from the high availability factor of both committed and uncommitted nuclear generation resources, the latter of which received bonus performance for all megawatts produced up to the level scheduled and dispatched by PJM.

It bears noting that these figures depict the bonus performance megawatts which received a share of bonus credits. As noted above in this section, resources that do not meet the energy offer requirements are not eligible to receive bonus performance credits and are excluded from the bonus performance megawatt values in this section.

Figure 90. Generation Bonus Performance Distribution by Fuel Type compared to Installed Capacity



Bonus Performance Rates and Credits

Total Non-Performance Charges are allocated, at the account level, as bonus performance credit to resources that have bonus megawatts based on their pro-rata share of total bonus performance megawatts. The average $/MW-interval rate across the performance assessment event for bonus megawatts was $188.85, or 75% of the non-performance penalty rate for the RTO. These rates are based on the total Non-Performance Charges assessed.

Table 23. Average Bonus Performance Rate (hourly average of five-minute interval values)

Hour Beginning (EPT)		Total Bonus MW	Total Non-Performance Charge	Bonus $/MW-Interval
Dec. 23, 2022	17:00	33,117.7	6,589,973.18	198.99
	18:00	33,930	6,505,727.97	191.74
	19:00	33,898.6	6,731,000.98	198.56
	20:00	34,137.8	6,827,351.73	199.99
	21:00	35,758.4	7,031,512.93	196.64
	22:00	33,776.9	6,532,125.94	193.39
Dec. 24, 2022	04:00	36,974.8	7,785,599.61	210.57
	05:00	36,834.1	7,799,035.09	211.73
	06:00	36,894.4	7,733,603.22	209.61
	07:00	35,959.9	7,768,289.54	216.03
	08:00	34,907.3	7,473,896.14	214.11
	09:00	35,080.8	7,034,963.27	200.54
	10:00	36,719.1	6,910,820.64	188.21
	11:00	37,178.9	6,858,699.63	184.48
	12:00	35,410.9	6,370,314.53	179.9
	13:00	33,338.6	5,704,554.02	171.11
	14:00	33,737.9	5,508,448.92	163.27
	15:00	34,685.8	5,831,635.11	168.13
	16:00	34,968.7	6,365,883.24	182.05
	17:00	33,292.8	6,103,588.46	183.33
	18:00	31,777.4	5,739,415.91	180.61
	19:00	31,695.2	5,314,600.31	167.68
	20:00	29,565.6	4,951,402.92	167.47
	21:00	29,992.6	5,033,588.91	167.83

Bonus credits paid to over-performing resources are based on Non-Performance Charges collected from under-performers. The bonus rates in the table above assume 100% collection of all Non-Performance Charges. To the extent that an account with under-performing resources is unable to pay their Non-Performance Charges, the total pool of bonus dollars to be paid out is reduced. This is achieved through the use of a bonus holdback.

Because both Non-Performance Charges and bonus credits for a given month are initially billed in the same billing statement, the amount of Non-Performance Charges that may be uncollected is unknown at the time the bill is issued. A bonus holdback is utilized to withhold an estimate of the potential uncollected Non-Performance Charges from the pool of bonus credits that are paid out in the initial bill. This hedges against the risk of paying out bonus credits that exceed the penalties that will actually be collected.

Once financial settlement occurs, PJM adjusts the bonus holdback to reflect observed nonpayment and issues adjustments to true-up the bonus credits paid with the total Non-Performance Charges collected. Ongoing reporting on the expected and actual bonus holdbacks for the billing of the Winter Storm Elliott performance assessment event is conducted at PJM Risk Management Committee meetings.[26] The
Settlement Timelines and Results section of this report contains additional details on the total Non-Performance Charges to be billed each month, and therefore total potential bonus credits to be paid, as well as actual Non-Performance Charges collected as of the time this report was issued.

Resources that have been committed to an FRR plan and elected the physical non-performance assessment option had bonus megawatts calculated for the Winter Storm Elliott performance assessment events. These megawatts are not eligible to receive bonus credits. However, they are eligible to net against shortfall megawatts within the FRR entity's portfolio when calculating the amount of additional capacity the FRR entity will be required to carry in the following delivery year's FRR plan as a result of under-performance during the event. The details on the FRR physical bonus megawatts cannot be posted for data confidentiality reasons.[27]

Demand Response and Price Responsive Demand Performance

Detailed performance of DR for the Winter Storm Elliott Performance assessment event is reviewed in the Load Management Performance Report.[28] A summary of these details on performance, shortfall, bonus and penalties are detailed below. The full report can be referenced for more detailed analysis.

Table 24 summarizes Load Management (emergency and pre-emergency Demand Response) performance for the two days. For Dec. 23, all Load Management resources with 30-minute or 60-minute lead times were dispatched by PJM. For Dec. 24, all Load Management resources were dispatched by PJM (this includes all 30-minute, 60-minute or 120-minute lead times). Overall average event performance during the mandatory compliance period (06:00 through 21:00) was 126%. Capacity compliance is primarily measured based on the "firm service level" approach. This is where a resource is committed to maintain load at or below a defined level. The capacity reduction represents the megawatts reduced based on their load levels during the event, compared to their winter peak load. Capacity load reductions can be significantly different from real-time energy load reductions, since load may already be at the committed level before the resource is dispatched. This is the driver for the relatively strong Capacity Performance for this event, versus the relatively weak energy load reduction performance outlined in the Operating Day section of this report.

Table 24. Load Management Event Summary for Dec. 23 and Dec. 24

Date	Product	Average Capacity		
		Committed (MW)	Reduction (MW)	Performance
Dec. 23	Emergency Load Management	186	167	90%
	Pre-Emergency Load Management	4,042	4,907	121%
Dec. 24	Emergency Load Management	287	218	76%
	Pre-Emergency Load Management	6,888	9,035	131%

[26] Risk Management Committee web page at PJM.com
[27] PJM Manual 33, Section 6.1
[28] See Load Management Performance Report section of PJM DR web page.

Table 25 summarizes PRD performance. PRD is required to ensure load is below the committed level when there is a PAI and LMP greater than the strike price provided by the PRD provider. The capacity reduction represents the megawatts reduced based on their load levels during the event, compared to their peak load contribution.

Table 25. PRD Event Summary for Dec. 23 and Dec. 24

Date	Product	Average Capacity Committed (MW)	Average Capacity Reduction (MW)	Average Capacity Performance
Dec. 23	Price Responsive Demand	209	90	43%
Dec. 24	Price Responsive Demand	230	117	51%

The shortfalls from capacity commitments receive Non-Performance Charges, whereas the performance above the commitment level receives a bonus payment. Economic energy reductions and cleared ancillary services offers during the event intervals are eligible for bonus payments. The non-performance penalty and bonus breakdown for DR and PRD is detailed in Table 26. The Load Management and PRD performance values have been aggregated in the table below to adhere to posting rules around market-sensitive data given the small number of Market Participants with PRD resources. [29]

Table 26. DR and PRD Non-Performance Charges and Bonus Credits

Date	Load Management & PRD: Non-Performance Charge ($)	Load Management & PRD: Bonus Credit ($)	Economic Energy / Ancillary Services Bonus Credit ($)
Dec. 23	$2,421,812	$16,193,113.36	$2,546,949.14
Dec. 24	$1,610,469	$62,125,444.36	$5,782,104.47
Total	$4,032,281	$78,318,558	$8,329,054

Settlement Timelines and Results

Non-performance assessments are billed starting three calendar months after the calendar month that included the performance assessment event and are spread across the remaining months in the delivery year. For the Winter Storm Elliott event, this means charges are billed starting in March 2023 and spread in three equal installments through the May 2023 billing statement. However, given the magnitude of the penalties for this event, PJM filed Tariff revisions to provide participants with the option of spreading their Non-Performance Charges across a nine-month period, subject to interest for the additional six months included in this billing option.

Monthly charges are billed by dividing the total dollar amount due for each account by either three or nine months, depending on which billing option the participant selected. Participants electing the nine-month billing option were billed starting in the March 2023 billing statement and will continue to be billed through the November 2023 billing statement. Bonus credits will be paid over the same time frame, with the amount credited each month equal to the amount of Non-Performance Charges collected each month. Based on the aforementioned elections, $524 million, or 30% of the total

[29] PJM Manual 33, Section 6.1

$1.8 billion in Non-Performance Charges for this event, will be billed over a three-month period. The remaining $1,276 million, or 70%, will be billed over a nine-month period and will be assessed $15 million in interest charges. [30]

The following table displays the total charges to be assessed each month, the total Non-Performance Charges that were not collected, and the resulting bonus credits available to be paid to bonus recipients as of June 21, 2023. Ongoing updates will be provided through the PJM Risk Management Committee meetings.

Table 27. Non-Performance Charges and Bonus Credits Invoiced

Billing Month	Total Non-Performance Charges ($)	Total Interest Charges ($)	Total Nonpayment ($)	Total Bonus Credits Paid (including interest) ($)
March 2023	$316,419,632.80	$1,704,168.62	$8,422,793.53	$309,701,007.89
April 2023	$316,419,632.80	$1,704,168.62	$7,877,961.45	$310,245,839.97
May 2023	$316,419,632.80	$1,704,168.62	$7,875,909.02	$310,247,892.40
June 2023	$141,724,275.13	$1,704,168.62	TBD	TBD
July 2023	$141,724,275.13	$1,704,168.62	TBD	TBD
August 2023	$141,724,275.13	$1,704,168.62	TBD	TBD
September 2023	$141,724,275.13	$1,704,168.62	TBD	TBD
October 2023	$141,724,275.13	$1,704,168.62	TBD	TBD
November 2023	$141,724,275.13	$1,704,168.62	TBD	TBD
Total	$1,799,604,549.20	$15,337,517.54	$24,176,664.01 (as of 6/21/2023)	$930,194,740.26 (as of 6/21/2023)

Government, Member and Media Outreach

PJM's Corporate Communications, Federal, and State & Member Services teams are responsible for communicating situation updates to, and answering inquiries from, the general public, stakeholders, and state and federal contacts through direct channels, as well as PJM.com, social media and traditional media. Corporate Communications regularly participates in PJM's annual Operations Winter Emergency Procedures Drill and Summer Emergency Procedures Drill. These drills include a call with Transmission Owner communications departments, in which a PJM Operations supervisor and PJM external communications staff provide a situation update and information on how PJM contacts them if needed in an emergency, including through an emergency alert tool managed by PJM's Business Continuity Department. Corporate Communications conducts a roll call of communicators during these drills and uses the occasion to update its Transmission Owner communicator contact list.

PJM's State Government Policy (SGP) Department prepares for emergency procedure communications and coordination with state emergency contacts throughout the year. These state emergency contacts, categorized by email and phone number (all-call list), are informed by the state agencies within the PJM footprint and serve as the primary point of contact to receive standard PJM emergency procedure notifications, which are sent by the designated on-call SGP employee.

SGP tests its ability to successfully communicate with the state emergency email and all-call lists during PJM's summer and winter emergency drills, as well as other emergency drills, such as the November 2022 Grid Security Drill. These summer and winter drills allow for state emergency contacts to familiarize (or re-familiarize) themselves with PJM's

[30] The interest charges collected on a monthly basis will be allocated to bonus performance credit recipients based on their ratio share of total bonus performance credits (under the assumption of 100% collection of all Non-Performance Charges).

emergency notifications, help PJM test its emergency communication channels with the states, and provide biannual checkpoints for PJM to curate the state emergency contact lists. The state emergency contact lists are also updated on an ad-hoc basis.

PJM external-facing communicators also participate in biannual GridEx exercises and Grid Security Drills, coordinating with both member communicators and other ISOs/RTOs as part of the scenarios.

Beginning with the 2021/2022 winter season, SGP and Operations leadership began holding winter operations calls with the PJM states to discuss winter preparedness and operational developments throughout the winter. The calls continued for the 2022/2023 winter season, with one meeting held with the states on Dec. 15, 2022.

The activation of PJM's crisis communication plans and outreach to members, states and the general public through national/local/social media appeared to help reduce electricity use and ensure the reliability of the grid. Member communicators expressed appreciation for PJM's handling of the media and willingness to do local media interviews. In addition, PJM continues to seek additional feedback on opportunities for better coordination to refine and enhance its crisis communications and outreach procedures.

The outreach by Corporate Communications, State & Member Services, and other PJM employees, and coordinated response by both member companies and state partners was effective. The Call for Conservation, which depends on members to relay the message to their retail customers, and the impact of consumers' resulting efforts, appeared to have led to a reduction in demand. Though it is difficult to measure precisely, electricity demand leveled off over the course of Saturday, and peak demand Saturday evening came in less than what was forecast.

While the conservation effort appeared to be successful, PJM is exploring further opportunities to maximize the reach of such appeals with states and Transmission Owners.

Event Communications

Starting on Dec. 21 through Dec. 23, Corporate Communications published on its news site, Inside Lines, a series of articles noting the Cold Weather Advisory and subsequent Cold Weather Alert updates, and amplified them on social media. On Dec. 23, conditions deteriorated as more generators continued to go offline, resulting in a Call for Conservation.

A Call for Conservation, as outlined in Manual 13, "instructs affected Transmission Owners to request the public to conserve electricity because of developing power supply problems." Transmission Owners are the most logical point of contact for retail customers, with PJM also broadcasting the conservation appeal via news release, PJM.com, social media and traditional media.

The decision to issue a Call for Conservation was made at approximately 23:30 on Friday, Dec. 23, so that both Transmission Owners and PJM's press release would reach any outlets or audiences that could respond late Friday into early Saturday morning and have some impact on the morning peak. PJM Corporate Communications and State & Member Services teams relayed system conditions and the Call for Conservation to the communications staff of PJM Transmission Owners, as well as state regulators and elected officials, throughout Winter Storm Elliott from Dec. 23 to Dec. 25.

Corporate Communications posted a news release on PJM.com at 23:54 and sent the release via email to Transmission Owner communicators, members and media contacts, and posted to Twitter and LinkedIn. PJM reissued the news release to our extensive media and member communicators' contact lists at 05:40, Dec. 24, and retweeted the Call for Conservation news release.

Corporate Communications activated its crisis communications plan at 05:45, Dec. 24, to make sure sufficient resources were available to handle outreach and media response needs Saturday and Sunday.

PJM noted the end of the Call for Conservation on Sunday, Dec. 25, with direct email to members, social media posts and video on PJM.com.

Transmission Owner Communicators

At approximately 21:50, Friday, Dec. 23, before PJM had made the decision to issue a Call for Conservation, PJM Corporate Communications scheduled a meeting with Transmission Owner communicators for 08:30, Saturday, Dec. 24, to provide utility partners a situational update. PJM also directly emailed Transmission Owner communicators the news release shortly after 00:00 Saturday.

This 08:30 Saturday meeting became PJM's main venue to request these members' support in broadcasting the Call for Conservation appeal. More than 30 partners (including elected officials and regulators in addition to members) joined in the effort to amplify the Call for Conservation to their customers, gaining nearly 1 million impressions on Twitter alone. PJM believes that the actions of these members, combined with PJM media outreach, helped to broadcast the Call for Conservation and flatten the load beginning at 07:15 Saturday, when the New Jersey Board of Public Utilities issued the first tweet in response to PJM's call.

PJM held an event review with Transmission Owner communicators on Jan. 9. This discussion informed Corporate Communications' observations and lessons learned from the event. Transmission Owner communicators stated that PJM's willingness to do interviews with local media was helpful to them as they dealt with both distribution outages and the transmission challenges highlighted by the Call for Conservation.

Federal

During the winter storm, PJM's Federal Government Policy group kept in close contact with FERC and the Department of Energy (DOE), consistent with its regular practice when emergency procedures are invoked. Communications are directed to FERC commissioners and their advisors, as well as to staff, throughout the Commission and reports on the system conditions with updates after the morning and evening peaks. In addition, PJM utilizes FERC's emergency notification procedures for such notices. PJM's reporting requirements to FERC are identified in in PJM Manual 13 and NERC Standard EOP-4.

In addition, the Federal Government Policy group similarly reaches out to DOE officials in the office of Cybersecurity, Emergency Security and Emergency Response (CESER) with updates after the morning and evening peaks. These early communications represented an early reach-out prior to PJM seeking to invoke the Section 202(c) process to obtain an emergency order from the Secretary of Energy.

Public/Media

PJM posted three video updates from System Operations leadership at the top of PJM.com homepage. The video was retweeted and reposted by customer-facing members as well as elected officials and regulators, used by State & Member Services to inform key stakeholders, and quoted or captured directly by media for use in broadcasts.

PJM responded to approximately 50 media requests, including at least 20 interviews on Dec. 24 and Dec. 25. PJM worked with customer-facing members' communications departments, who referred inquiries to PJM. In follow-up discussions, these members indicated that PJM's willingness to handle local media requests freed them to handle other pressing issues at the distribution level.

PJM deployed Twitter, LinkedIn and Facebook to draw attention to the video updates provided on PJM.com. Posts promoting the video received more than 300,000 impressions. Total impressions from PJM posts during Winter Storm Elliott were:

Twitter – 519,298	Facebook – 27,368	LinkedIn – 27,182

The PJM Now app is a popular source for system alerts (including emergency procedures) and allows users to track energy use, fuel mix and emissions data. More than 1,800 unique users accessed the app during Winter Storm Elliott, and the app was opened 6,600 times on Dec. 25 – compared with an average daily use of 750 app opens. The PJM Now app experienced unprecedented usage that slowed service during the storm, and PJM's Inside Lines news site went down Saturday because of unprecedented usage. Corporate Communications has taken steps to enhance these platforms so that similar usage levels will not result in the same performance issues as experienced during Winter Storm Elliott.

Between Dec. 23 and Dec. 25, Corporate Communications tracked more than 70 news stories noting PJM's Call for Conservation. This included national and newswire coverage from CNN, the Associated Press and Bloomberg, as well as regional coverage from television, radio and print media throughout the region PJM serves.

States

Heading into Winter Storm Elliott, SGP began its emergency procedure communications with the states on Dec. 21, relaying the issuance of a Cold Weather Alert for the Western Region of PJM on Dec. 23. SGP then communicated the issuance of a second Cold Weather Alert on Dec. 23 for the entire PJM region that began on Dec. 24.

As the storm progressed on Dec. 23 and emergency conditions arose, SGP relayed PJM's emergency procedure positioning to the state emergency email contacts as this information was provided to SGP by PJM's Operations Team. This included the escalation and de-escalation of emergency conditions heading into Dec. 24. SGP also communicated PJM's Dec. 24 Call for Conservation to the states, but instead of sending the conservation message to just the standard state emergency contacts, SGP utilized a broader list of state contacts that also included the emergency contacts.

In addition to member utilities, social media reach was greatly extended by participation of elected officials. Two governors tweeted the Call for Conservation and attracted two of the top three Twitter impression totals. Corporate Communications and SGP are working together to maximize impact from state partners when issuing a conservation appeal.

As SGP continued to provide system condition updates to its state emergency contacts the morning of Dec. 24, these communications progressed to individualized updates to the states via the SGP regulatory managers. Periodic system condition updates continued to be provided to the standard state emergency contacts through Dec. 25, although no new emergency procedures were issued by PJM.

Stakeholders

Figure 91 presents the stakeholder messages made between Dec. 23 and Dec. 25, color-coded by audience. These communications are in addition to direct communications made to generators, Load Serving Entities, Market Participants and others in emergency conditions as well as normal operating situations. General email notifications about the start and end of Performance Assessment Intervals are made for general awareness of all members. Members directly impacted by Performance Assessment Intervals receive separate, direct notifications in real time.

Figure 91. Stakeholder Messages

Type	Audience	Message	Time Sent Dec. 23	Time Sent Dec. 24	Time Sent Dec. 25
Maximum Generation Emergency Action Email	Stakeholders	Notifying the beginning of a Performance Assessment Interval	19:01		
Email Notification	Transmission Owner communications departments	A winter operation update conference call to be held with PJM Corporate Communications at 08:30, Dec. 24.	21:54		
Email Notification	Stakeholders	The Maximum Emergency Generation Action has ended at 23:00, Dec. 23, along with the corresponding Performance Assessment Interval.	23:32		
Email Notification	Stakeholders	The issuance of a public call for electricity conservation shortly before midnight		00:31	
Maximum Generation Emergency Action Email	Stakeholders	General email notification to stakeholders, notifying the beginning of a Performance Assessment Interval		05:19	
PJM New Release Distribution List	PJM news release distribution list	On public Call for Conservation sent to PJM news release distribution lists		05:40	
Generation Owner Request	Generation Owners with actual/potential emission restrictions	Update and maintain this information in Markets Gateway for PJM to prepare a 202(c) filing with the Department of Energy.		10:31	
Email Notification	Stakeholders	PJM's 202(c) filing with the Department of Energy requesting for a finding that an electricity reliability emergency exists within the PJM region		17:38	
Email Notification	Stakeholders	On the Department of Energy's issuance of the requested emergency order and providing the names, municipalities and zip codes of the generation resources subject to the order		19:27	
Email Notification	Stakeholders	The Maximum Emergency Generation Action has ended at 20:00, Dec. 24, along with the corresponding Performance Assessment Interval.		22:14	
Email Notification	Stakeholders	Announcing the end of the public call for electricity conservation			11:54
Technical Communication	Market Participants	Announcing that Dec. 26 Day-Ahead Market results are posted and that the rebid period was extended to 14:45			14:31

Maximum Generation Emergency Action Email
PJM New Release Distribution List
Technical Communication
Email Notification
Generation Owner Request

Conclusion

The observations and recommendations in this report were developed through intensive data gathering, analysis and feedback from various groups regarding areas of study. Learning Teams were convened for operations and markets that included subject matter experts not directly involved in this report, adding their independent evaluation of the research presented.

Extreme events like Winter Storm Elliott offer opportunities to improve our rules, practices, preparations and processes. Following the 2014 Polar Vortex, PJM took important steps to improve reliability by implementing Capacity Performance incentives for generation to perform during emergencies, strengthening winterization rules and refining operating procedures.

In 2021 following the lessons of Winter Storm Uri that impacted Texas and surrounding regions, PJM introduced rules to help Transmission Owners ensure service to critical facilities in emergencies, improve information sharing with the natural gas industry, and strengthen load-shedding preparation and practices. PJM also enhanced data gathering from generating resources, including more frequent fuel and equipment inventory reporting in the face of global supply chain issues. In advance of the 2022/2023 winter, PJM updated its winter preparation generator checklist to include cold weather operating limits.

The 30 recommendations listed at the outset of this report will be acted on through multiple stakeholder forums, including the ongoing Critical Issue Fast Path – Resource Adequacy process that was initiated to produce a set of improvements to PJM capacity market rules by October. Other recommendations will be pursued in various PJM forums to include the Electric Gas Coordination Senior Task Force, Operating Committee and the Market Implementation Committee.

While PJM and its members were able to maintain reliability during Winter Storm Elliott, the increasing volatility of weather patterns and reliance on gas generation underscore the need to advance the performance of operations, planning and markets for the increasing risk presented by the winter season.

Appendix A

Two-Settlement Market Mechanics

As described in the Operating Day section of this report, the PJM Energy Market consists of two markets: a Day-Ahead Market and a Real-Time Market. The Day-Ahead Energy Market offers an opportunity for Market Participants to lock in their positions in advance of an operating day in a financially firm way to reduce their risk of exposure to real-time prices.

Market Participants have until 11:00 the day prior to the operating day to submit their bids and offers for the Day-Ahead Market. Generation resources, regardless of fuel type, fall into one of two categories, Capacity Resources or Energy Resources. If available, all Generation Capacity Resources that have a Reliability Pricing Model (RPM) or Fixed Resource Requirement (FRR) Commitment must submit offer data into the Day-Ahead Market and may elect either to Self-Schedule or offer the resource to PJM for scheduling as a PJM RTO-Scheduled Resource. Several types of entities participate in the Day-Ahead Energy Market.

- Generation Owners submit their offers to supply power and will adjust offers for factors, such as cost of fuel.
- Load Serving Entities will submit bids for their expected need for electricity for the operating day. For a typical operating day, PJM observes approximately 90–95% of real-time load cleared in the Day-Ahead Market with the remainder clearing and settling in the Real-Time Market.
- Market Participants also may submit various "virtual transactions," which are offers to buy or sell at particular locations that are generally not associated with physical generation or load. Market Participants may use virtual transactions for various reasons including hedging risk on physical positions and arbitraging price differences between the Day-Ahead and Real-Time Markets.

When the Day-Ahead Market closes at 11:00 on the day prior to an operating day, PJM begins the process of clearing the Day-Ahead Market, and the results are made available to Market Participants by 13:30 the day prior to the operating day. The Day-Ahead Market is cleared so that the cost to serve physical and virtual demand is minimized, while still respecting the physical operating limits of the transmission system. Commitments in the Day-Ahead Market are financially binding on participants. Any differences between those commitments and what occurs in the operating day is settled in the Real-Time Energy Market.

Generation and Demand Resources may alter their offers for use in the Real-Time Energy Market during the following periods:

- The Generation Rebidding Period, which is defined from the time the office of interconnection posts the results of the Day-Ahead Energy Market until 14:15
- Starting at 18:30 (typically after the Reliability Assessment and Commitment Run is completed) and up to 65 minutes prior to the start of the operating hour

There are often cases where the load levels cleared in the Day-Ahead Market do not meet the level of forecasted load for the operating day. To address this, PJM has a process called the Reliability Assessment Commitment (RAC) that begins after 16:15, which commits additional supply to meet the forecasted load plus reserves, while minimizing start-up and no-load cost of those commitments. The focus of this commitment is reliability and the objective is to minimize start-up and no-load costs for any additional resources that are committed. Using the most up-to-date weather forecast, load forecast, transmission facility and generator availability, and other information, PJM commits additional supply, if necessary, to satisfy both expected loads and the needed reserves for the operating day.

Leading up to and throughout the operating day, PJM examines updated information and system conditions and acts to continually balance generation with the need for electricity and maintaining adequate reserves to prepare for unexpected issues. PJM manages changes from day-ahead commitments and schedules in the Real-Time Energy Market using the offers from generation resources and Demand Resources to jointly minimize the cost of energy and reserves while maintaining energy balance and respecting the limits of the transmission system. Any differences in supply and demand from the Day-Ahead Energy Market commitments are settled at price levels determined by the Real-Time Energy Market.

Energy and Reserve Market Pricing

Locational Marginal Price (LMP) is defined as the marginal price for energy at the location where the energy is delivered or received and is based on forecasted system conditions and the latest approved Real-Time Security Constrained Economic Dispatch program solution. LMP is expressed in dollars per megawatt-hour ($/MWh). LMPs are determined as an output of the co-optimization of energy and reserves and is the cost to provide the next increment of energy while respecting reserve requirements, transmission constraints and losses.

PJM's real-time dispatch and LMP calculation systems include Operating Reserve Demand Curves (ORDCs) for 30-minute Operating Reserves, Primary Reserves and Synchronized Reserves. During times where an area of PJM is experiencing a reserve shortage, those ORDCs are used to set reserve prices and may have a direct impact on LMPs. Specifically, when the marginal energy megawatts are provided by converting a megawatt of reserves into a megawatt of energy, the resulting LMP takes into account the opportunity cost of that exchange. This direct impact of the ORDCs on LMPs during a reserve shortage is referred to as shortage or scarcity pricing. More information on this is contained in PJM Manual 11.

In performing this LMP calculation, the cost of serving an increment of load at each bus from each resource associated with an eligible energy offer is calculated as the sum of the following three components of LMP:

- System Energy Price – This is the system-wide, unconstrained price. The System Energy Price may include a portion of the defined Reserve Penalty Factors should a reserve shortage exist.
- Congestion Price – This is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from or consumption by the resource on transmission line loadings.
- Loss Price – This is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from or consumption by the resource on transmission losses.

LMPs are calculated in both the Day-Ahead Energy Market and the Real-Time Energy Market. The Day-Ahead LMP is calculated based on the Security Constrained Economic Dispatch for the Day-Ahead Market. The Real-Time LMP is calculated based on the approved Security Constrained Economic Dispatch solution for the target dispatch interval.

PJM procures resources to meet the required Reserve Services in the Day-Ahead Reserve Markets:

- Synchronized Reserve Service – Reserve capability that can be converted fully into energy or load that can be removed from the system within 10 minutes of the request from the PJM system operator and must be provided by equipment electrically synchronized to the system. Synchronous Reserves can only be satisfied by online resources that are able to respond in 10 minutes or less.

- **Contingency (Primary) Reserve Service** – Reserve capability satisfied by online or offline resources that are able to respond in 10 minutes or less. Contingency (Primary) Reserve is reserve capability that can be converted fully into energy or load that can be removed from the system within 10 minutes of the request from the PJM system operator.
- **30-Minute Reserve Service** – Reserve capability satisfied by online or offline resources that are able to respond in 30 minutes or less.

Figure 92 presents the relationship among the three reserve services described above.

Figure 92. Reserve Services

Regulation Market

The PJM Regulation Market provides PJM participants with a market-based system for the purchase and sale of the Regulation ancillary service. Resource owners submit specific offers for Regulation Capability and Regulation Performance, and PJM utilizes these offers together with energy offers and resource schedules from the Markets Gateway System as input data to the Ancillary Service Optimizer (ASO), which is an hour-ahead Market Clearing Engine. ASO optimizes the RTO dispatch profile and forecasts LMPs to determine hourly commitments of Regulation to meet the requirement. The Real-Time Security Constrained Economic Dispatch (RT SCED) program jointly optimizes Energy and Reserves subject to transmission constraints, Reserve Requirements and prior committed Regulation.

The five-minute Regulation Market Clearing Price (RMCP) and Regulation Market Performance Clearing Price (RMPCP), are calculated by the Locational Price Calculator and are used to derive the five-minute Regulation Market Capability Clearing Price (RMCCP). These clearing prices are then used in market settlements to determine the credits awarded to providers and charges allocated to purchasers of the Regulation service.

PJM uses resource schedules, Regulation offers, and energy offers from the Markets Gateway System as input data to the ASO to provide the lowest cost alternative for the procurement of Regulation for each hour of the operating day. The lowest cost alternative for this service is achieved through a co-optimization with Synchronized Reserves, Primary Reserves, 30-Minute Reserves and energy. Within the co-optimization, an RTO dispatch profile is forecasted along with LMPs for the market hour. Using the dispatch profile and forecasted LMPs, an opportunity cost, adjusted by the applicable Performance Score and Benefits Factor, is estimated for each resource that is eligible to provide Regulation. The estimated opportunity cost for Demand Resources is zero. The adjusted lost opportunity cost is added to the adjusted regulation capability cost and the adjusted regulation performance cost to make the adjusted total regulation offer cost. The adjusted total regulation offer cost is then used to create the merit order price.

All available regulating resources are then ranked in ascending order of their merit order prices, and the lowest cost set of resources necessary to simultaneously meet the PJM Regulation Requirement, PJM Synchronized Reserve Requirement, PJM Primary Reserve Requirement, and PJM 30-minute Reserve Requirement and provide Energy in that hour is determined. If there is an excess of self-scheduled and zero-cost offers over and beyond the Regulation Requirement, PJM uses resource-specific historic performance scores, selecting those resources with the highest performance scores, as a tie-breaker to determine which set of resources to commit to meet the Regulation Requirement. The least cost set of Regulation resources identified through this process are then committed.

Prices for Regulation are calculated simultaneously with Energy and Reserves every five minutes by the Locational Pricing Calculator (LPC) in the pricing run. The highest merit order price associated with this lowest cost set of resources awarded Regulation becomes the RMCP. The RMPCP is calculated as the highest adjusted performance offer from the set of cleared resources. The RMCCP is the difference between RMCP and RMPCP.

Financial Transmission Rights

Financial Transmission Rights (FTRs) are financial instruments awarded to bidders in the FTR Auction and entitle the holder to receive a stream of revenues (or charges) based on hourly Day-Ahead Congestion Price differences across a path. They provide hedging and protections against future locational energy price differences.

A Market Participant can obtain FTRs in the Annual Auction, Long-Term Auctions, Monthly Auction and secondary market.

PJM awards FTRs based on the capability of the transmission system. There must be adequate revenue from congestion to fund the FTRs that are awarded. Revenue adequacy issues occur when PJM under-collects congestion revenue to fund FTRs.

The hourly economic value of an FTR Obligation is based on the Financial Transmission Right MW reservation and the difference between the Day-Ahead Congestion Price at the point of delivery and the point of receipt of the Financial Transmission Right. The hourly economic value of a Financial Transmission Right Obligation is positive (a benefit to the FTR holder) when the Day-Ahead Congestion Price at the point of delivery is higher than the Day-Ahead Congestion Price at the point of receipt. The hourly economic value of a Financial Transmission Right Obligation is negative (a liability to the FTR holder) when the Day-Ahead Congestion Price at the point of receipt is higher than the Day-Ahead Congestion Price at the point of delivery.

The hourly economic value of a Financial Transmission Right Option is based on the Financial Transmission Right MW reservation and the difference between the Day-Ahead Congestion Price at the point of delivery and the point of receipt of the Financial Transmission Right when that difference is positive. The hourly economic value of a Financial Transmission Right Option is positive (a benefit to the FTR holder) when the Day-Ahead Congestion Price at the point of delivery is higher than the Day-Ahead Congestion Price at the point of receipt. The hourly economic value of a Financial Transmission Right Option is zero (neither a benefit nor a liability to the FTR holder) when the Day-Ahead Congestion Price at the point of receipt is higher than the Day-Ahead Congestion Price at the point of delivery.

The total target allocation for a Market Participant for each hour is then the sum of the target allocations for all of the Market Participant’s FTRs. Note, if the DA LMPDelivery or the DA LMPReceipt is an aggregate zone, the following formula is used:

$$Target = FTR * \Sigma Load\ Percentage * (DALMPDelivery - i - DALMPReceipt)$$

Where:

- FTR Financial Transmission Rights between the designated Load Aggregation Zone and the designated bus, in megawatts
- Load Percentage – the percentage of the load at time of annual peak associated with each individual load bus in the Load Aggregation Zone designated in the FTR

PJM compares the total of all Transmission Congestion Credit target allocations to the total Transmission Congestion Charges for the PJM Control Area in each hour resulting from the Day-Ahead Market.

- If the total of the target allocations is less than the total Day-Ahead Transmission Congestion Charges, the Day-Ahead Transmission Congestion Credit for each FTR is equal to its target allocation. All excess Day-Ahead Transmission Congestion Charges are distributed at the end of the month.
- If the total of the target allocations is equal to the total Day-Ahead Transmission Congestion Charges, the Day-Ahead Transmission Congestion Credit for each FTR is equal to its target allocation.
- If the total of the target allocations is greater than the total Day-Ahead Transmission Congestion Charges, the Day-Ahead Transmission Congestion Credit for each FTR is equal to its target allocation only for those customer accounts whose total target allocation position for their FTR portfolio is net negative for the hour. Customer accounts whose total target allocation position for their FTR portfolio is net positive for the hour receives a share of the total Day-Ahead Transmission Congestion Charges (including revenues resulting from the collection of the net negative target allocation positions) in proportion to its target allocation. The shortfalls in hourly Day-Ahead Transmission Congestion Credits compared to target allocations may be offset by excess charges from other hours in the end of the month accounting.
- If the total Day-Ahead Transmission Congestion Charges is negative, the Day-Ahead Transmission Congestion Credit for each FTR is equal to its target allocation only for those customer accounts whose total target allocation position for their FTR portfolio is net negative for the hour. If the revenues resulting from the collection of the net negative target allocation positions is more than enough to cover the negative Day-Ahead Transmission Congestion Charge, then any remaining revenues are distributed as Day-Ahead Transmission Congestion Credits to customer accounts whose total target allocation position for their FTR portfolio is net positive for the hour, in proportion to their target allocations. If the revenues resulting from the collection of the net negative target allocation positions is not enough to cover the negative Day-Ahead Transmission Congestion Charge, then no Day-Ahead Transmission Congestion Credits are awarded to customer accounts whose total target allocation position for their FTR portfolio is net positive, and the remaining Day-Ahead Transmission Congestion Charge liability will be subtracted from the total monthly excess prior to the month-end distribution described in the next section. The shortfalls in hourly Day-Ahead Transmission Congestion Credits compared to target allocations may be offset by excess charges from other hours in the end of the month accounting.