Introduction

Q1 2025 in Review

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

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

The primary challenge currently facing the energy market is ensuring that load can be met in extreme weather conditions, primarily winter weather to date but likely to include both winter and summer weather. The contrast between PJM's approach to Winter Storm Elliott in December 2022 and Polar Vortex 2025 illustrates the issues and demonstrates a productive path forward.

PJM chose to prepare for the weather related risks of Polar Vortex 2025 (January 19 through 23, 2025) in very different ways than for Winter Storm Elliott. The results of Winter Storm Elliott demonstrated that capacity market PAI incentives were not effective. During Winter Storm Elliott, PJM's approach assumed that generators would be ready for extreme weather and that generators would behave exactly as their parameters described, all as a result of generators wanting to avoid paying PAI penalties. The interactions between PJM commitment and dispatch instructions and generators did not work well because the market design failed to recognize basic physical realities of the generators and the realities of gas procurement and transportation. In preparing for Polar Vortex 2025, rather than rely on PAI incentives to provide assurance that generators would be ready for cold weather, PJM took direct steps to ensure a reliable outcome. The results of Polar Vortex 2025 vindicated PJM's strategy. PJM took conservative measures to ensure reliability by scheduling resources well in advance of the day-ahead energy market. PJM took additional advance actions to ensure transmission reliability by scheduling specific resources to address specific issues. As there is no multiday market, actions taken before the market starts generally result in some uplift to the extent that the units do not clear in the day-ahead market. Based on this experience, the rules governing PJM's actions in such events should be more transparent, clearly documented, and include defined criteria for taking such actions. In addition, there should be rules about the energy offers used for these advance commitments, and uplift rules should be revised to account for the multiday nature of these commitments. The lessons learned include that conservative operations are preferred to the Winter Storm Elliott approach of simply assuming that generators would respond, that increased uplift is the expected result and that the process of conservative operations and advance commitments needs to be improved, formalized and made as market oriented as possible in order to minimize uplift and make uplift as predictable as possible. This is a pragmatic, practical, targeted approach to managing system risk during extreme weather events. This is a clear, tested alternative to reliance on PAI incentives. Reliance on an expanded demand curve for reserves (ORDC) that is limited to the day-ahead and real-time markets is not a viable alternative to conservative operations for managing this risk. An ORDC cannot address all identifiable and specific sources of risk on any particular day and cannot produce advance commitments.

Uplift during Polar Vortex 2025 was a result of out of market commitments made by PJM in anticipation of the cold weather. PJM committed units on Friday, January 17 for the January 19, 20 and 21 operating days. These commitments were made in advance of the day-ahead energy market, before offers were due. Some of the units cleared the day-ahead energy market economically and did not require uplift payments because their offers were covered by the day-ahead LMP. The rest of the units committed in advance that did not clear the day-ahead market received balancing operating reserves credits because their offers were not covered by the real-time LMP. PJM made these commitments to mitigate generator performance risks based on available information about startup and operating uncertainty due to expected cold temperatures and gas supply illiquidity. PJM also committed specific units in advance to ensure transmission system reliability. These units received day-ahead uplift.

The commitments made prior to the day-ahead market resulted primarily from conservative operations, which PJM declared from January 20 through January 23, 2025, but also included unit commitments for transmission constraints. The commitments for conservative operations were made to ensure that generators that in previous events had performed poorly due to cold temperatures and gas supply issues, had the ability to respond. These commitments were not made to meet reserve requirements.

Balancing operating reserve credits (uplift) were the result of multiday commitments to minimize generation performance risk under conservative operations (about two thirds of the total). Those units, mostly gas-fired combined cycle units, were committed ahead of time but did not clear the day-ahead market. The day-ahead operating reserve credits (uplift) (about one third of the total uplift) were the result of units committed for transmission reliability in the day-ahead market (rather than conservative operations), these payments were made to a very small number of units that were specifically required to resolve identified risks on the transmission grid.

The basic lesson learned is that conservative operations is an effective way to ensure reliability during extreme weather. The broader lessons relate to the capacity market design. The PAI incentives did not work during Winter Storm Elliott. After Elliott, the impacts of PAIs were appropriately attenuated by changes to the definition of a PAI and by limits on the maximum annual penalty to 1.5 times the relevant capacity market clearing price. ELCC values, particularly for thermal resources, are understated because they rely heavily on the performance of thermal resources during Winter Storm Elliott and the original Polar Vortex in 2014 and therefore on PJM's approach to commitment and dispatch during those events. PJM did not engage in the same comprehensive approach to conservative operations in either event. Thermal resources' response in Polar Vortex 2025 was much better than in Winter Storm Elliott as a direct result of PJM's approach to the impending weather. Assuming that PJM will continue to use a similar approach to future weather events, ELCC values must be modified to reflect that fact.

The capacity market is getting tighter. The result will be higher capacity market prices. In a well designed market, capacity market prices reflect the underlying supply and demand fundamentals. The results of the last capacity market auction (the 2025/2026 BRA) illustrate the amplified impact of not getting the details of the market design right when the market is tight. The MMU analysis shows that while a significant increase in capacity market payments was based on the fundamentals, market design and market power issues resulted in actual capacity market payments that were approximately twice as high as needed in the 2025/2026 auction.[1]

The capacity market is already tight, meaning that supply is approximately equal to forecast demand plus the required reserve margin. Even if the capacity market issues identified by the MMU were resolved, the market would still be tight and prices correspondingly high. The capacity market is tight primarily as a combined result of the recent addition of large loads and the expected addition of more large loads, almost all of which, to date, are connected to the grid as transmission customers. Large load additions have already had a significant impact and will have additional significant impacts on other customers as a result of required transmission upgrades and higher capacity market prices, regardless of the details of interconnection.

Rather than directly addressing the impact of large load additions, PJM has implemented an extremely high maximum price on the demand curve (VRR curve) in the capacity market and proposes an even higher maximum price. The maximum price has a significant effect when the market is tight and

1 *See* MMU reports analyzing the 2025/2026 RPM Base Residual Auction, "Analysis of the 2025/2026 RPM Base Residual Auction - Part A," (Sep. 20, 2024), "Analysis of the 2025/2026 RPM Base Residual Auction - Part B," (Oct. 15, 2024), "Analysis of the 2025/2026 RPM Base Residual Auction - Part C," (Nov. 6, 2024), "Analysis of the 2025/2026 RPM Base Residual Auction - Part D," (Dec. 6, 2024), "Analysis of the 2025/2026 RPM Base Residual Auction - Part E," (Jan. 31, 2025), Analysis of the 2025/2026 RPM Base Residual Auction - Part F," (Feb. 4, 2025). These reports can be found at <https://www.monitoringanalytics.com/reports/Reports/2024.shtml>.

therefore clears at or near the maximum price. The market is likely to clear in upcoming auctions at the maximum price as a direct result of the prior and planned addition of large loads in PJM. PJM's maximum price proposal was temporarily replaced by PJM's agreement with the Governor of Pennsylvania on the maximum and minimum price filing for the next two BRAs.

Markets cannot solve all problems. It is clear that continuing to simply accept the interconnection of large loads that cannot be served reliably because there is not adequate dispatchable capacity, and no immediate ability to add new capacity that matches the 8,760 hour demands of large loads, is not a reasonable path forward. That path leads to continued shortfalls, continued maximum prices, and continued calls to abandon markets and return to cost of service regulation. The calls to return to cost of service regulation include the current proposal by PJM's consultant for the accelerated use of PJM's euphemistically named reliability backstop option in the capacity market.

The prices in capacity market auctions are a result of both demand and supply conditions. There are current issues with the addition of both demand and supply that must be addressed in a comprehensive, transparent and stable manner in order to help ensure that the market can manage to balance demand and supply. It is not enough to simply assert that the market will solve all these problems. Markets need rules. Markets need exogenous parameters. Some of the current issues result from rules that create unnecessary administrative barriers to entry of new supply or create uncertainty about the addition of new large loads. PJM needs a process for expediting and streamlining the entry of new generation without distorting the related PJM market principles. PJM needs a process for managing the addition of large loads to the system without distorting the capacity market design. FERC relies on competitive markets to be a more effective substitute for economic regulation. FERC's rules about market design and rules governing demand and supply are essential to creating the conditions under which markets can work. These are public, regulatory decisions because they are about competitive outcomes that are in the interests of all market participants.

The addition of large loads has very similar impacts on capacity and energy market dynamics regardless of whether the loads are added as full transmission customers or as co-located customers. The primary difference is that the large loads would pay a full share of transmission costs if added as full transmission customers and would not pay a full share if co-located. Co-located loads would also lean on the grid for backup.

The problem for other customers taking wholesale power service from PJM is that the addition of large loads without adequate planning imposes very significant capacity market costs on everyone else. The result has been and, without adequate planning, will continue to be scarcity conditions in the capacity market and calls for dramatic price increases for other customers. The question is how to serve the potentially very large increases in load in a way that does not threaten reliability or the ability of PJM markets to reliably serve all load at the lowest possible cost, i.e. without imposing billions of dollars of additional costs on other customers in order to serve large loads.

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

There are three broad options for addressing the addition of large loads in PJM. The first option would allow EDCs to sign up new large loads, subject these additions only to a transmission planning analysis (necessary study) and permit interconnection of the loads without consideration of the reliability impacts including the impacts on the energy and capacity markets. The second option, co-location, would rely on private bilateral transactions to remove capacity from the PJM markets with de minimis planning requirements and dedicate it to specific large loads without consideration of the reliability impacts including the impacts on the energy and capacity markets. The third option would rely on PJM to more comprehensively and transparently plan for the addition of large loads by ensuring that large loads are not added unless there is new generation to match them. The third option is the pragmatic, practical choice given the realities of the PJM markets, including the current lags in the generation interconnection queue and the increase in large load additions.

Within the PJM planning option, the ideal solution to the issues created by the addition of large loads is for the large loads to bring their own generation. That can take a variety of forms but would entail the large loads taking responsibility for adding new generation to the grid that has locational and temporal characteristics reasonably matched to their load profile. This option should include an expedited interconnection process for large loads and their matching new generation that is consistent with the PJM queue processes. This option would balance the desire of large loads to interconnect quickly with the need to maintain reliability

A goal of market design should be to be consistent and predictable and transparent. A consistent, predictable and transparent design would provide a stable investment environment for generators and a stable price environment for customers who both consume and invest. New supply requires competitive incentives and a stable investment environment. The objective of the market design should be markets that work, markets that work for generators and markets that work for customers. The objective of the market design should also be markets that are transparent and understandable to market participants and to regulators. The capacity market design should be as simple as possible to meet its objectives. The current capacity market design does not meet these standards.

The level of uncertainty created by PJM's ELCC design combined with the extreme PAI penalties has a negative impact on the risk and economic viability of units considering retirement and weakens the incentives to invest in PJM generation. Despite assertions about the efficacy of PAI penalties, there are effectively zero performance incentives when PJM addresses high load days through conservative operations, as PJM has appropriately done since Winter Storm Elliott, because the probability of a PAI event is extremely low. The ELCC should be unit specific. The ELCC should be based on unit specific hourly supply and demand matching. Capacity resources should be paid only when available to perform. Capacity resources should be paid based on actual hourly performance during the delivery year.

The current PJM interconnection queue does not include adequate thermal capacity to replace the potentially retiring thermal capacity. The apparent level of MW in the interconnection queues substantially overstates the level of capacity MW that is likely to actually go into service in PJM markets for all resource types. While there are legitimate differences of opinion about the exact level and timing of the need, PJM needs additional capacity resources and PJM needs to remove inefficient barriers to entry based on interconnection queue rules in order to facilitate that entry. PJM has taken essential steps to do exactly that, including the Interconnection Process Reform changes to the queue management process and the recent filing and approval of the RRI and SIS rules. More needs to be done.

While the short term RRI process is a clear improvement, PJM should request the ongoing authority to advance projects at any time that can more effectively address immediate reliability issues including the issues that result from requests to retire existing resources regardless of whether they qualify for RMR status. While it is important to respect the existing, improved PJM queue process, it is essential to provide strong and clear incentives for projects to actually resolve reliability issues and to actually guarantee timely in service dates in order to help ensure that the queue is not a mirage as it has been in significant part for its recent history. Recognizing that improved queue rules are being implemented, the history of queue projects and whether they become actual in service capacity resources suggests strongly that such incentives have not been provided by the queue process.

One of the benefits of competitive power markets is that changes in input prices and changes in the balance of supply and demand are reflected immediately in energy prices for both price decreases and price increases. Energy prices increased in the first three months of 2025 from the first three months of 2024. The real-time load-weighted average LMP in the first three months of 2025 increased $21.19 per MWh, or 68.3 percent from the first three months of 2024, from $31.01 per MWh to $52.20 per MWh.

Of the $21.19 per MWh increase, $15.85 per MWh (74.8 percent) was in the fuel and consumables cost components of LMP, $2.43 per MWh (11.4 percent) was in the transmission constraint penalty factor component of LMP, $1.83 per MWh (8.6 percent) was in the market power components of LMP, -$0.32

per MWh (-1.5 percent) was in the emissions cost components of LMP, and -$0.22 per MWh (-1.0 percent) was in the scarcity component of LMP.

The total cost of wholesale power increased $23.65 per MWh, or 43.8 percent, from $53.95 per MWh in the first three months of 2024 to $77.60 per MWh in the first three months of 2025. Energy (70.2 percent), capacity (4.6 percent) and transmission charges (23.0 percent) are the three largest components of the total cost of wholesale power, comprising 97.8 percent of the total cost per MWh in the first three months of 2025. Starting in the third quarter of 2019, the cost of transmission per MWh of wholesale power has been higher than the cost of capacity.

In the first three months of 2025, generation from coal units increased 31.3 percent, generation from natural gas units decreased 0.8 percent, generation from oil units increased 91.8 percent, generation from wind units increased 12.6 percent, and generation from solar units increased 61.8 percent compared to the first three months of 2024.

Energy market net revenues are significantly affected by energy prices and fuel prices. Energy prices, gas prices and coal prices increased in the first three months of 2025 compared to the first three months of 2024. The net effects were that in the first three months of 2025, average energy market theoretical net revenues increased by 45 percent for a new combustion turbine (CT), increased by 51 percent for a new combined cycle (CC), increased by 202 percent for a new coal plant (CP), increased by 67 percent for a new nuclear plant, increased by 243 percent for a new diesel (DS), increased by 82 percent for a new onshore wind installation, increased by 80 percent for a new offshore wind installation and increased by 121 percent for a new solar installation.

The real-time hourly average load in the first three months of 2025 increased by 7.1 percent from the first three months of 2024, from 89,478 MWh to 95,801 MWh.

Changes in forward energy market prices significantly affect the expected profitability of nuclear plants in PJM. Based on forward prices as of December 31, 2024, for energy, and known forward prices for capacity including an assumed clearing price of $325/MW-Day for the 2026/2027 Delivery Year, all the nuclear plants in PJM are expected to cover their avoidable costs from energy and capacity market revenues in 2025 and 2026, without subsidies.

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

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

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

PJM Market Summary Statistics

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

Table 1-1 PJM market summary statistics: January through March, 2024 and 2025[2]

	2024 (Jan-Mar)	2025 (Jan-Mar)	Percent Change
Average Hourly Load Plus Exports (MWh)	95,970	102,154	6.4%
Average Hourly Generation Plus Imports (MWh)	97,822	104,313	6.6%
Peak Load Plus Export (MWh)	142,821	150,646	5.5%
Peak Load Excluding Export (MWh)	130,293	140,043	7.5%
Installed Capacity at March 31 (MW)	178,449	179,017	0.3%
Load Weighted Average Real Time LMP ($/MWh)	$31.01	$52.20	68.3%
Total Congestion Costs ($ Million)	$321.00	$503.30	56.8%
Total Uplift Credits ($ Million)	$76.3	$462.7	506.4%
Total PJM Billing ($ Billion)	$12.35	$18.68	51.3%

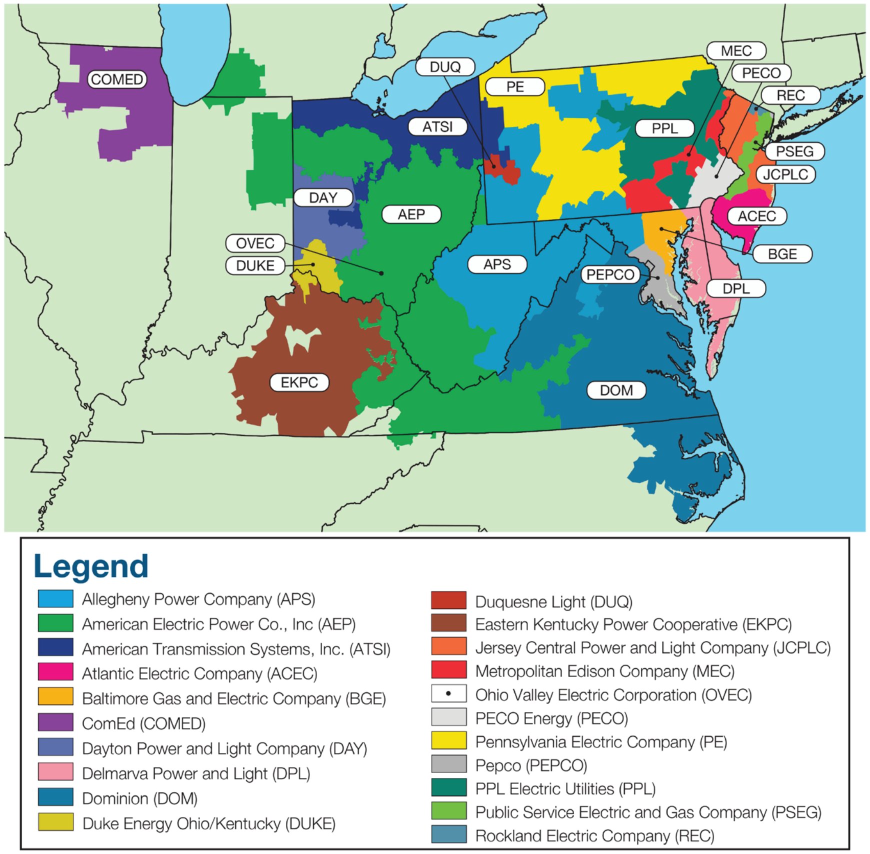
PJM Market Background

The PJM Interconnection, L.L.C. (PJM) operates a centrally dispatched, competitive wholesale electric power market that, as of March 31, 2025, had installed generating capacity of 179,017 megawatts (MW) and 1,097 members including market buyers, sellers and traders of electricity in a region including more than 65 million people in all or parts of 13 states (Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia) and the District of Columbia (Figure 1-1).[3] [4] [5]

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

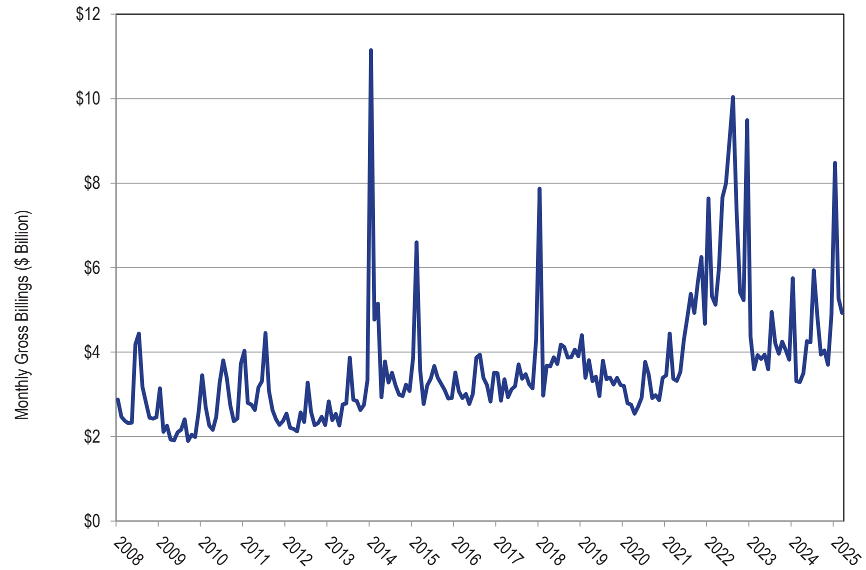
2 In Table 1-1, the MMU used the total PJM billing values provided by PJM through 2018. Starting in 2019, the total PJM billing values in Table 1-1 are modified by the MMU, to more accurately reflect PJM total billing. The total PJM billing shown in Table 1-1 is different from the total cost shown in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

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



In the first three months of 2025, PJM had gross billings of $18.68 billion, an increase of 51.3 percent from $12.35 billion in the first three months of 2024. (Figure 1-2).

Figure 1-2 PJM reported monthly billings ($ Billion): January 2008 through March 2025[6]



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

PJM introduced energy pricing with cost-based offers and market-clearing nodal prices on April 1, 1998, and market-clearing nodal prices with market-based offers on April 1, 1999. PJM introduced the Daily Capacity Market on January 1, 1999, and the Monthly and Multimonthly Capacity Markets for the January through May 1999 period. PJM implemented FTRs on May 1, 1999.

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

PJM implemented the day-ahead energy market and the regulation market on June 1, 2000. PJM modified the regulation market design and added a market in Synchronized Reserve on December 1, 2002. PJM introduced an Auction Revenue Rights (ARR) allocation process and an associated Annual FTR Auction effective June 1, 2003. PJM introduced the RPM capacity market effective June 1, 2007. PJM implemented the DASR market on June 1, 2008, and eliminated it on October 1, 2022. PJM introduced the Capacity Performance capacity market design effective on August 10, 2015, with the Base Residual Auction for 2018/2019.[7] [8]

Conclusions

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

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

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

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

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

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

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

Energy Market Conclusion

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

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

8 Analysis of 2024 market results requires comparison to prior years. During calendar years 2004 and 2005, PJM conducted the phased integration of five control zones: COMED, American Electric Power (AEP), The Dayton Power & Light Company (DAY), Duquesne Light Company (DUQ) and Dominion (DOM). In June 2011, PJM integrated the American Transmission Systems, Inc. (ATSI) Control Zone. In January 2012, PJM integrated the Duke Energy Ohio/Kentucky (DUKE) Control Zone. In June 2013, PJM integrated the Eastern Kentucky Power Cooperative (EKPC). In December 2018, PJM integrated the Ohio Valley Electric Corporation (OVEC.) By convention, control zones bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company. For additional information on the integrations, their timing and their impact on the footprint of the PJM service territory prior to 2024, see *2023 Annual State of the Market Report for PJM*, Appendix A: "PJM Overview."

Table 1-2 The energy market results were competitive

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

- The aggregate market structure was evaluated as partially competitive because the aggregate market power test based on pivotal suppliers indicates that the aggregate day-ahead market structure was not competitive on 87.8 percent of the days in the first three months of 2025. The hourly HHI (Herfindahl-Hirschman Index) results indicate that the PJM aggregate energy market in the first three months of 2025 was, on average, unconcentrated by FERC HHI standards. The average HHI was 695 with a minimum of 577 and a maximum of 850. The baseload segment of the supply curve was unconcentrated. The intermediate segment of the supply curve was moderately concentrated on average. The peaking segment of the supply curve was highly concentrated. The fact that the average HHI is in the unconcentrated range does not mean that the aggregate market was competitive in all hours. As demonstrated for the day-ahead market, it is possible to have pivotal suppliers in the aggregate market even when the HHI level is not in the highly concentrated range. It is possible to have an exercise of market power even when the HHI level is not in the highly concentrated range. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. The HHI is not a definitive measure of structural market power.
- The local market structure was evaluated as not competitive due to the highly concentrated ownership of supply in local markets created by transmission constraints and local reliability issues. The results of the three pivotal supplier (TPS) test, used to test local market structure, indicate the existence of market power in local markets created by transmission constraints. The local market performance is competitive as a result of the application of the TPS test. Transmission constraints create the potential for the exercise of local market power. The goal of PJM's application of the three pivotal supplier test is to identify local market power and offer cap to competitive offers, correcting for structural issues created by local transmission constraints. There are, however, identified issues with the definition of cost-based offers and the application of market power mitigation to resources whose owners fail the TPS test that need to be addressed because unit owners can exercise market power even when they fail the TPS test.
- Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both the day-ahead and real-time energy markets, although the behavior of some participants both routinely and during periods of high demand represents economic withholding. The ownership of marginal units is concentrated. The markups of pivotal suppliers in the aggregate market and of many pivotal suppliers in local markets remain unmitigated due to the lack of aggregate market power mitigation and the flawed implementation of offer caps for resources that fail the TPS test. The markups of those participants affected LMP.
- Market performance was evaluated as competitive because market results in the energy market reflect the outcome of a competitive market, as PJM prices are set, on average, by marginal units operating at, or close to, their marginal costs in both day-ahead and real-time energy markets, although high markups for some marginal units did affect prices.
- Market design was evaluated as effective because the analysis shows that the PJM energy market resulted in competitive market outcomes. In general, PJM's energy market design provides incentives for competitive behavior and results in competitive outcomes. In local markets, where market power is an issue, the market design identifies market power and causes the market to provide competitive market outcomes in most cases although issues with the implementation of market power mitigation and development of cost-based offers remain. The role of UTCs in the day-ahead energy market continues to cause concerns. Market design implementation issues, including inaccuracies in modeling of the transmission system and of generator capabilities as well as inefficiencies in price formation, undermine market efficiency in the energy market. The

implementation of fast start pricing on September 1, 2021, undermined market efficiency by setting inefficient prices that are inconsistent with the dispatch signals.

- PJM markets are designed to promote competitive outcomes derived from the interaction of supply and demand in each of the PJM markets. Market design itself is the primary means of achieving and promoting competitive outcomes in PJM markets. One of the MMU's core functions is to identify actual or potential market design flaws.[9] The approach to market power mitigation in PJM has focused on market designs that promote competition (a structural basis for competitive outcomes) and on mitigating market power in instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. FERC relies on effective market power mitigation when it approves market sellers to participate in the PJM market at market based rates.[10] In the PJM energy market, market power mitigation occurs primarily in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.[11] There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power even when market power mitigation rules are applied. These issues need to be addressed, but, so far, PJM and FERC have failed to address them.[12] [13] [14] Some units with market power have positive markups and some have inflexible parameters, which means that the cost-based offer was not used and that the process for offer capping units that fail the TPS test does not consistently result in competitive market outcomes in the presence of market power. There are issues related to the definition of gas costs includable in energy offers that need to be addressed. There are issues related to the level of maintenance expense includable in energy offers that need to be addressed. There are currently no market power mitigation rules in place that limit the ability to exercise market power when aggregate market conditions are tight and there are pivotal suppliers in the aggregate market. Aggregate market power needs to be addressed. Market design must reflect appropriate incentives for competitive behavior, the application of local market power mitigation needs to be fixed, the definition of a competitive offer needs to be fixed, and aggregate market power mitigation rules need to be developed. The importance of these issues is amplified by the rules permitting cost-based offers in excess of $1,000 per MWh.

9 OATT Attachment M (PJM Market Monitoring Plan).
10 See *Refinements to Horizontal Market Power Analysis for Sellers in Certain Regional Transmission Organization and Independent System Operator Markets*, Order No. 861, 168 FERC ¶ 61,040 (2019); *order on reh'g*, Order No. 861-A; 170 FERC ¶ 61,106 (2020).
11 The market performance test means that offer capping is not applied if the offer does not exceed the competitive level and therefore market power would not affect market performance.
12 175 FERC ¶ 61,231 (2021).
13 185 FERC ¶ 61,158 (2023).
14 189 FERC ¶ 61,060 (2024).

Capacity Market Conclusion

The Market Monitoring Unit (MMU) analyzed market design, market structure, participant conduct and market performance in the PJM Capacity Market, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.[15] The conclusions are a result of the MMU's evaluation of the 2025/2026 Base Residual Auction.[16] [17] [18] [19] [20] [21]

Table 1-3 The capacity market results were not competitive

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

15 The values stated in this report for the RTO and LDAs refer to the aggregate level including all nested LDAs unless otherwise specified. For example, RTO values include the entire PJM market and all LDAs. Rest of RTO values are RTO values net of nested LDA values.
16 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part A," (September 20, 2024) <https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_A_20240920.pdf>.
17 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part B," (October 15, 2024) <https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_B_20241015.pdf>.
18 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part C," (October 15, 2024) <https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_C_20241106.pdf>.
19 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part D," (December 6, 2024) <https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_D_20241206.pdf>.
20 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part E," (January 31, 2025). <https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_E_20250131.pdf>.
21 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part F," (February 4, 2025) <https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_F_20250204.pdf>
See "Analysis of the 2025/2026 RPM Base Residual Auction - Part D," (December 6, 2024) <https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_D_20241206.pdf>.

- The aggregate market structure was evaluated as not competitive. For almost all auctions held from 2007 to the present, the PJM capacity market failed the three pivotal supplier test (TPS), which is conducted at the time of the auction.[22] Structural market power is endemic to the capacity market.
- The local market structure was evaluated as not competitive. For almost every auction held, all LDAs have failed the TPS test, which is conducted at the time of the auction.[23]
- Participant behavior was evaluated as not competitive in the 2025/2026 BRA. The offers of most market sellers were competitive after the Commission order corrected the definition of the market seller offer cap.[24] Market power mitigation measures were applied when the capacity market seller failed the market power test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price. However, a significant level of categorically exempt resources did not offer and the result was to increase the clearing prices above the competitive level.
- Market performance was evaluated as not competitive based on the 2025/2026 Base Residual Auction as a result of the failure to offer of categorically exempt resources, the flaws in the Effective Load Carrying Capability (ELCC) design including the failure to correctly define the reliability contribution of thermal resources in the winter and the failure to include reliability must run (RMR) capacity in the supply curve.
- Market design was evaluated as mixed because while there are many positive features of the capacity market design, there are several features of the RPM design which still threaten competitive outcomes. These include the details of PJM's ELCC implementation, the failure to apply the RPM must offer requirement consistently to demand resources, the inclusion of performance assessment interval (PAI) penalties, the exclusion of RMR resources from supply, the use of gross CONE as the maximum price on the VRR curve, the definition of DR which permits inferior products to substitute for capacity, the replacement capacity issue, the definition of unit offer parameters, and the inclusion of imports which are not substitutes for internal capacity resources.[25]

22 In the 2008/2009 RPM Third Incremental Auction, 18 participants in the RTO market passed the TPS test. In the 2018/2019 RPM Second Incremental Auction, 35 participants in the RTO market passed the test. In the 2023/2024 RPM Third Incremental Auction, 36 participants in the RTO passed the TPS test.

23 In the 2012/2013 RPM Base Residual Auction, six participants included in the incremental supply of EMAAC passed the TPS test. In the 2014/2015 RPM Base Residual Auction, seven participants in the incremental supply in MAAC passed the TPS test. In the 2021/2022 RPM First Incremental Auction, two participants in the incremental supply in EMAAC passed the TPS test. In the 2021/2022 RPM Second Incremental Auction, two participants in the incremental supply in EMAAC passed the TPS test. In the 2023/2024 RPM Third Incremental Auction, eight participants in MAAC passed the TPS test.

24 176 FERC ¶ 61,137 (2021), *order denying reh'g*, 178 FERC ¶ 61,121 (2022), *appeal denied*, EPSA, et al. v. FERC, Case No. 21-1214, et al. (DC Cir. October 10, 2023). The Commission recognized the market power problem and issued an order correcting the PJM tariff, eliminating the prior offer cap and establishing a competitive market seller offer cap set at net ACR, effective September 2, 2021.

Synchronized Reserve Market Conclusion

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

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

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

- The synchronized reserve market structure was evaluated as not competitive due to supplier concentration. The RTO Reserve Zone was unconcentrated in the day-ahead market and moderately concentrated in the real-time market. The MAD Reserve Subzone was moderately concentrated in the day-ahead market and highly concentrated in the real-time market.
- Participant behavior was evaluated as competitive because the market rules require all available reserves to offer at cost-based offers.
- Market performance was evaluated as not competitive because the interaction of participant behavior with the market design does not result in competitive prices as a result of PJM's changes to the ORDC. In an attempt to counter poor unit specific synchronized reserve performance, PJM unilaterally and inappropriately extended the first step of the operating reserve demand curve (ORDC) for synchronized reserve, known as the synchronized reserve reliability requirement, in May 2023, raising prices for synchronized reserves and energy.

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

- Market design was evaluated as flawed based on PJM's modifications to the ORDC. PJM previously adopted reforms, including several based on MMU recommendations, removing both physical and economic withholding from the market.
- Significant communications technology issues when calling resources during synchronized reserve events have resulted in slow response from resources. On December 17, 2024, PJM implemented an electronic deployment of reserves via an augmented dispatch signal, but PJM does not require that resources be able to receive this signal.

Nonsynchronized Reserve Market Conclusion

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

Table 1-5 The nonsynchronized reserve market results were competitive

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

- The nonsynchronized reserve market structure was evaluated as not competitive due to supplier concentration for primary reserve. The RTO Reserve Zone was unconcentrated in the day-ahead market and moderately concentrated in the real-time market. The MAD Reserve Subzone was moderately concentrated in the day-ahead market and highly concentrated in the real-time market.
- Participant behavior was evaluated as competitive because all available reserves are included by the PJM markets software, so withholding is not possible.
- Market performance was evaluated as competitive because the interaction of participant behavior with the market design results in competitive prices.
- Market design was evaluated as effective.

Secondary Reserve Market Conclusion

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

Table 1-6 The secondary reserve market results were competitive

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

- The secondary reserve market structure was evaluated as competitive, because the supply of 30-minute reserves was not concentrated in the real-time market nor in the day-ahead market.
- Participant behavior was evaluated as competitive because all available reserves are included by the PJM software, so withholding is not possible.
- Market performance was evaluated as competitive because the combination of a competitive market structure and competitive participation resulted in competitive market outcomes.
- The market design was evaluated as effective because the market rules ensure competitive market offers and require repayment of offline cleared secondary reserves that are not available when called on to provide energy in 30 minutes.

Regulation Market Conclusion

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

Table 1-7 The regulation market results were not competitive

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

- The regulation market structure was evaluated as not competitive because the PJM Regulation Market failed the three pivotal supplier (TPS) test in 94.5 percent of the hours in the first three months of 2025.
- Participant behavior in the PJM Regulation Market was evaluated as competitive in the first three months of 2025 because market power mitigation requires competitive offers when the three pivotal supplier test is failed, although the inclusion of a positive margin is not consistent with competitive offers.
- Market performance was evaluated as not competitive, because all units are not paid the same price on an equivalent MW basis.
- Market design was evaluated as flawed. The market design has failed to correctly incorporate a consistent implementation of the marginal benefit factor in optimization, pricing and settlement. The market results continue to include the incorrect definition of opportunity cost. The result is significantly flawed market signals to existing and prospective suppliers of regulation.

FTR Auction Market Conclusion

The *2025 Quarterly State of the Market Report for PJM: January through March* focuses on the first ten months of the 2024/2025 planning period as well as the 2024/2025 Long Term and Annual FTR auctions and ARR allocation, specifically covering June 1, 2024, through March 31, 2025. The Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance, including market size, concentration, offer behavior, and price. The MMU concludes that the PJM FTR auction market results were partially competitive in the first three months of 2025.

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

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

- Market structure was evaluated as competitive. The ownership of FTR obligations is unconcentrated for the individual years of the 2024/2027 Long Term FTR Auction, the 2024/2025 Annual FTR Auction and each period of the Monthly Balance of Planning Period Auctions for prevailing flow FTRs. The ownership of FTR options is moderately or highly concentrated for every Monthly FTR Auction period and unconcentrated for the 2024/2025 Annual FTR Auction. Ownership of FTRs is disproportionately (87.9 percent) by financial participants. The ownership of ARRs is unconcentrated.
- Participant behavior was evaluated as partially competitive because ARR holders who are the sellers of FTRs have no option to set an acceptable sale price and are not permitted to participate in the market clearing in any way and are not assured they will receive 100 percent of auction revenues.
- Market performance was evaluated as partially competitive because of the significant and persistent flaws in the market design. Sellers, the ARR holders, cannot set a sale price. Buyers can reclaim some of their purchase price after the market clears if the product does not meet a profitability target. The market resulted in a substantial shortfall in congestion payments to load and significant and unsupportable disparities among zones in the share of congestion returned to load. FTR purchases by financial entities remain persistently profitable in part as a result of the flaws in the market design.
- Market design was evaluated as flawed because there are significant, fundamental and persistent flaws in the basic ARR/FTR design. The FTR auction market is not actually a market because the sellers have no independent role in the process. ARR holders cannot determine the price at which they are willing to sell rights to congestion revenue. Buyers have the ability to reclaim some of the price paid for FTRs after the market clears and, as a result, sellers are not assured they will receive 100 percent of auction revenues. The market design is not an efficient or effective way to ensure that the rights to all congestion revenues are assigned to load. The product sold to FTR buyers is incorrectly defined as target allocations rather than a share of congestion revenue. ARR holders' rights

to congestion revenues are not correctly defined because the contract path based assignment of congestion rights is inadequate and incorrect. The ongoing PJM subjective intervention in the FTR market that affects market fundamentals is also an issue and a symptom of the fundamental flaws in the design. The product, the quantity of the product and the price of the product are all incorrectly defined.

- The fact that load is not able to define its willingness to sell FTRs or to set the prices at which it is willing to sell FTRs and the fact that load is required to return some of the cleared auction revenue to FTR buyers when FTR profits are deemed to be not adequate, means that the FTR design does not actually function as a market and is evidence of basic flaws in the market design.

Role of MMU

FERC assigns three core functions to MMUs: reporting, monitoring and market design.[26] These functions are interrelated and overlap. The PJM Market Monitoring Plan establishes these functions, providing that the MMU is responsible for monitoring: compliance with the PJM Market Rules; actual or potential design flaws in the PJM Market Rules; structural problems in the PJM Markets that may inhibit a robust and competitive market; the actual or potential exercise of market power or violation of the market rules by a Market Participant; PJM's implementation of the PJM Market Rules or operation of the PJM Markets; and such matters as are necessary to prepare reports.[27]

Reporting

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

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

Monitoring

To perform its monitoring function, the MMU screens and monitors the conduct of Market Participants under the MMU's broad purview to monitor, investigate, evaluate and report on the PJM Markets.[28] The MMU has direct, confidential access to FERC.[29] The MMU may also refer matters to the attention of state commissions.[30]

The MMU monitors market behavior for violations of FERC Market Rules and PJM Market Rules, including the actual or potential exercise of market power.[31] The MMU will investigate and refer "Market Violations," which refer to any of "a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies..."[32] [33] [34]

26 18 CFR § 35.28(g)(3)(ii); see also *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶31,281 (2008) ("Order No. 719"), *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶31,292 (2009), *reh'g denied*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

27 OATT Attachment M § IV; 18 CFR § 1c.2.

28 OATT Attachment M § IV.

29 OATT Attachment M § IV.K.3.

30 OATT Attachment M § IV.H.

31 OATT § I.1 ("FERC Market Rules" mean the market behavior rules and the prohibition against electric energy market manipulation codified by the Commission in its Rules and Regulations at 18 CFR §§ 1c.2 and 35.37, respectively; the Commission-approved PJM Market Rules and any related proscriptions or any successor rules that the Commission from time to time may issue, approve or otherwise establish… "PJM Market Rules" mean the rules, standards, procedures, and practices of the PJM Markets set forth in the PJM Tariff, the PJM Operating Agreement, the PJM Reliability Assurance Agreement, the PJM Consolidated Transmission Owners Agreement, the PJM Manuals, the PJM Regional Practices Document, the PJM-Midwest Independent Transmission System Operator Joint Operating Agreement or any other document setting forth market rules.")

32 FERC defines manipulation as engaging "in any act, practice, or course of business that operates or would operate as a fraud or deceit upon any entity." 18 CFR § 1c.2(a)(3). Manipulation may involve behavior that is consistent with the letter of the rules, but violates their spirit. An example is market behavior that is economically meaningless, such as equal and opposite transactions, which may entitle the transacting party to a benefit associated with volume. Unlike market power or rule violations, manipulation must be intentional. The MMU must build its case, including an inference of intent, on the basis of market data.

33 OATT § I.1.

34 The MMU has no prosecutorial or enforcement authority. The MMU notifies FERC when it identifies a significant market problem or market violation. OATT Attachment M § IV.I.1. If the problem or violation involves a market participant, the MMU discusses the matter with the participant(s) involved and analyzes relevant market data. If that investigation produces sufficient credible evidence of a violation, the MMU prepares a formal referral and thereafter undertakes additional investigation of the specific matter only at the direction of FERC staff. *Id.* If the problem involves an existing or proposed law, rule or practice that exposes PJM markets to the risk that market power or market manipulation could compromise the integrity of the markets, the MMU explains the issue, as appropriate, to FERC, state regulators, stakeholders or other authorities. The MMU may also initiate, participate as a party or provide information or testimony in regulatory or other proceedings.

The MMU also monitors PJM for compliance with the rules, in addition to market participants.[35]

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

If cost-based offers do not accurately reflect short run marginal cost, the market power mitigation process does not ensure competitive pricing in PJM markets. The MMU evaluates the fuel cost policy for every unit as well as the other inputs to cost-based offers. PJM Manual 15 does not clearly or accurately describe the short run marginal cost of generation. Manual 15 should be replaced with a straightforward description of the components of cost offers based on short run marginal costs and the correct calculation of cost offers. The MMU evaluates every offer cap in each capacity market (RPM) auction using data submitted to the MMU through web-based data input systems developed by the MMU.[36]

The MMU also reviews operational parameter limits included with unit offers, evaluates compliance with the requirement to offer into the energy and capacity markets, evaluates the economic basis for unit retirement requests and evaluates and compares offers in the day-ahead and real-time energy markets.[37] [38] [39] [40]

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

The PJM markets monitored by the MMU include market related procurement processes conducted by PJM, such as for Black Start resources included in the PJM system restoration plan.[41] [42]

The MMU also monitors transmission planning, interconnections and rules for vertical market power issues, and with the introduction of competitive transmission development policy in Order No. 1000, horizontal market power issues.[43]

Market Design

In order to perform its role in PJM market design, the MMU evaluates existing and proposed PJM Market Rules and the design of the PJM Markets.[44] The MMU initiates and proposes changes to the design of such markets or the PJM Market Rules in stakeholder or regulatory proceedings.[45] In support of this function, the MMU engages in discussions with stakeholders, State Commissions, PJM Management, and the PJM Board; participates in PJM stakeholder meetings or working groups regarding market design matters; publishes proposals, reports or studies on such market design issues; and makes filings with the Commission on market design, market rules and market rule implementation issues, including complaints or petitions.[46] The MMU also recommends changes to the PJM Market Rules to the staff of the Commission's Office of Energy Market Regulation, State Commissions, and

35 OATT Attachment M § IV.C.
36 OATT Attachment M–Appendix § II.E.
37 OATT Attachment M–Appendix § II.B.
38 OATT Attachment M–Appendix § II.C.
39 OATT Attachment M–Appendix § IV.
40 OATT Attachment M–Appendix § VII.
41 OATT Attachment M–Appendix § II(p).
42 OATT Attachment M–Appendix § III.
43 OA Schedule 6 § 1.5.
44 OATT Attachment M § IV.D.
45 *Id.*
46 *Id.*; see also, e.g., 171 FERC ¶ 61,039; 167 FERC ¶ 61,084 at PP 70–76, *reh'g denied*, 168 FERC ¶ 61,141.

the PJM Board.[47] The MMU may provide in its annual, quarterly and other reports "recommendations regarding any matter within its purview."[48]

New Recommendations

Consistent with its core function to "[e]valuate existing and proposed market rules, tariff provisions and market design elements and recommend proposed rule and tariff changes," the MMU recommends specific enhancements to existing market rules and implementation of new rules that are required for competitive results in PJM markets and for continued improvements in the functioning of PJM markets.[49]

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

New Recommendations from Section 10, Ancillary Services

- The MMU recommends that PJM maintain a full list of all units subject to the Primary Frequency Response generator requirements. (Priority: Medium. New Recommendation. Status: Not adopted.)
- The MMU recommends that PJM create the necessary tariff/manual language to properly enforce compliance with the NERC mandated Primary Frequency Response generator requirements. (Priority: Medium. New Recommendation. Status: Not adopted.)

47 *Id.*
48 OATT Attachment M § VI.A.
49 18 CFR § 35.28(g)(3)(ii)(A); see also OATT Attachment M § IV.D.

Total Cost of Wholesale Power

The total cost of wholesale power is the average total cost per MWh of wholesale electricity in PJM markets.[50] The costs of each component and subcomponent may vary by location and time period. The total costs are the sum of the total charges for the individual billing line items in each category divided by real time load, even when a specific category is not charged on that basis. The total cost of wholesale power and the components of that cost are presented for informational purposes and should not be used to calculate the costs of any specific market activity in PJM. The total cost includes the cost of energy, capacity, transmission service, ancillary services, and administrative fees billed through PJM systems. Table 1-9 shows the total cost, by component, for the first three months of 2024 and 2025.

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

Each of the components in Table 1-9 is defined in PJM's Open Access Transmission Tariff (OATT) and PJM Operating Agreement and each is collected through PJM's settlement process.[51]

Table 1-9 shows that energy, capacity and transmission charges are the three largest components of the total cost per MWh of wholesale power, comprising 97.8 percent of the total cost per MWh in the first three months of 2025. The total cost of energy per MWh increased by $23.18 from $31.33 in the first three months of 2024 to $54.51 in the first three months of 2025, an increase of 74.0 percent. The total cost of capacity per MWh increased by $.10 from $3.47 in the first three months of 2024 to $3.57 in the first three months of 2025, an increase of 2.8 percent. The total cost of transmission per MWh increased by $0.23 from $17.60 in the first three months of 2024 to $17.83 in the first three

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

months of 2025, an increase of 1.3 percent. The total cost per MWh of wholesale power increased by 23.65 from $53.95 in the first three months of 2024 to $77.60 in the first three months of 2025, an increase of 43.8 percent.

Table 1-9 Total cost per MWh by category: January through March, 2024 and 2025[52 53 54]

Category	2024 (Jan-Mar) $/MWh	2024 (Jan-Mar) ($ Millions)	2024 (Jan-Mar) Percent of Total	2025 (Jan-Mar) $/MWh	2025 (Jan-Mar) ($ Millions)	2025 (Jan-Mar) Percent of Total	Percent Change
Energy	$31.33	$6,119	58.1%	$54.51	$11,274	70.2%	74.0%
Day Ahead Energy	$32.11	$6,273	59.5%	$53.00	$10,963	68.3%	65.0%
Balancing Energy	$0.44	$87	0.8%	$1.09	$226	1.4%	147.0%
ARR Credits	($1.29)	($251)	(2.4%)	($1.31)	($271)	(1.7%)	1.6%
Self Scheduled FTR Credits	($0.37)	($72)	(0.7%)	($0.91)	($189)	(1.2%)	147.3%
Balancing Congestion	$0.40	$78	0.7%	$0.97	$200	1.2%	143.3%
Emergency Energy	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Inadvertent Energy	$0.00	$1	0.0%	($0.01)	($2)	(0.0%)	(476.2%)
Load Response - Energy	$0.01	$3	0.0%	$0.03	$7	0.0%	118.2%
Emergency Load Response	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Energy Uplift (Operating Reserves)	$0.39	$75	0.7%	$2.23	$462	2.9%	480.2%
Marginal Loss Surplus Allocation	($0.41)	($81)	(0.8%)	($0.76)	($156)	(1.0%)	82.2%
Market to Market Payments	$0.04	$8	0.1%	$0.17	$35	0.2%	312.2%
Capacity	$3.47	$678	6.4%	$3.57	$738	4.6%	2.8%
Capacity (Capacity Market and FRR)	$3.37	$658	6.2%	$3.44	$712	4.4%	2.2%
Capacity Part V (RMR)	$0.10	$20	0.2%	$0.13	$27	0.2%	23.0%
Load Response - Capacity	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Transmission	$17.60	$3,438	32.6%	$17.83	$3,689	23.0%	1.3%
Transmission Service Charges	$14.91	$2,912	27.6%	$15.10	$3,123	19.5%	1.3%
Transmission Enhancement Cost Recovery	$2.60	$508	4.8%	$2.64	$546	3.4%	1.5%
Transmission Owner (Schedule 1A)	$0.09	$18	0.2%	$0.09	$19	0.1%	0.2%
Transmission Seams Elimination Cost Assignment (SECA)	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Transmission Facility Charges	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Ancillary	$0.87	$170	1.6%	$1.03	$213	1.3%	18.2%
Reactive	$0.49	$96	0.9%	$0.45	$93	0.6%	(8.2%)
Regulation	$0.21	$41	0.4%	$0.32	$67	0.4%	56.0%
Black Start	$0.09	$17	0.2%	$0.08	$16	0.1%	(9.7%)
Synchronized Reserves	$0.08	$15	0.1%	$0.16	$33	0.2%	102.9%
Secondary Reserves	$0.00	$0	0.0%	$0.00	$1	0.0%	30.1%
Non-Synchronized Reserves	$0.01	$1	0.0%	$0.02	$3	0.0%	196.7%
Day Ahead Scheduling Reserve (DASR)	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Administration	$0.68	$132	1.3%	$0.66	$137	0.9%	(2.0%)
PJM Administrative Fees	$0.62	$122	1.2%	$0.61	$127	0.8%	(1.5%)
NERC/RFC	$0.04	$8	0.1%	$0.04	$9	0.1%	1.2%
RTO Startup and Expansion	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Other	$0.01	$2	0.0%	$0.00	$1	0.0%	(49.1%)
Total Price	$53.95	$10,538	100.0%	$77.60	$16,051	100.0%	43.8%
Total Day Ahead Load	193,714			203,801			5.2%
Total Balancing Load	(1,616)			(3,034)			87.7%
Total Real Time Load	195,330			206,835			5.9%
Total Cost ($ Billions)	$10.54			$16.05			52.3%

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

Table 1-10 shows the inflation adjusted average cost, by component, for the first three months of 2024 and 2025. To calculate the inflation adjusted average costs, the individual components' costs are deflated using the US Consumer Price Index for all items, Urban Consumers (with a base period of January 1998).[55]

Table 1-10 Inflation adjusted total cost per MWh by category: January through March, 2024 and 2025[56] [57]

Category	2024 (Jan-Mar) $/MWh	2024 (Jan-Mar) ($ Millions)	2024 (Jan-Mar) Percent of Total	2025 (Jan-Mar) $/MWh	2025 (Jan-Mar) ($ Millions)	2025 (Jan-Mar) Percent of Total	Percent Change
Energy	$16.35	$3,194	58.0%	$27.65	$5,720	70.0%	69.1%
Day Ahead Energy	$16.76	$3,273	59.5%	$26.89	$5,561	68.1%	60.4%
Balancing Energy	$0.23	$45	0.8%	$0.56	$115	1.4%	140.1%
ARR Credits	($0.67)	($131)	(2.4%)	($0.66)	($137)	(1.7%)	(1.1%)
Self Scheduled FTR Credits	($0.19)	($38)	(0.7%)	($0.46)	($96)	(1.2%)	140.4%
Balancing Congestion	$0.21	$40	0.7%	$0.49	$102	1.2%	137.1%
Emergency Energy	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Inadvertent Energy	$0.00	$0	0.0%	($0.01)	($1)	(0.0%)	(463.0%)
Load Response - Energy	$0.01	$2	0.0%	$0.02	$3	0.0%	110.8%
Emergency Load Response	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Energy Uplift (Operating Reserves)	$0.20	$39	0.7%	$1.14	$235	2.9%	464.2%
Marginal Loss Surplus Allocation	($0.22)	($42)	(0.8%)	($0.38)	($79)	(1.0%)	77.1%
Market to Market Payments	$0.02	$4	0.1%	$0.08	$18	0.2%	302.3%
Capacity	$1.86	$363	6.6%	$1.95	$404	4.9%	5.2%
Capacity (Capacity Market and FRR)	$1.80	$352	6.4%	$1.89	$391	4.8%	4.8%
Capacity Part V (RMR)	$0.05	$11	0.2%	$0.07	$14	0.2%	20.0%
Load Response - Capacity	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Transmission	$9.17	$1,790	32.5%	$9.04	$1,870	22.9%	(1.4%)
Transmission Service Charges	$7.76	$1,516	27.5%	$7.65	$1,583	19.4%	(1.4%)
Transmission Enhancement Cost Recovery	$1.35	$265	4.8%	$1.34	$277	3.4%	(1.3%)
Transmission Owner (Schedule 1A)	$0.05	$10	0.2%	$0.05	$10	0.1%	(2.5%)
Transmission Seams Elimination Cost Assignment (SECA)	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Transmission Facility Charges	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Ancillary	$0.45	$88	1.6%	$0.52	$108	1.3%	15.1%
Reactive	$0.26	$50	0.9%	$0.23	$47	0.6%	(10.6%)
Regulation	$0.11	$21	0.4%	$0.16	$34	0.4%	51.8%
Black Start	$0.04	$9	0.2%	$0.04	$8	0.1%	(12.1%)
Synchronized Reserves	$0.04	$8	0.1%	$0.08	$17	0.2%	97.6%
Secondary Reserves	$0.00	$0	0.0%	$0.00	$0	0.0%	26.7%
Non-Synchronized Reserves	$0.00	$1	0.0%	$0.01	$2	0.0%	189.7%
Day Ahead Scheduling Reserve (DASR)	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Administration	$0.35	$69	1.2%	$0.34	$69	0.8%	(4.6%)
PJM Administrative Fees	$0.32	$63	1.2%	$0.31	$64	0.8%	(4.1%)
NERC/RFC	$0.02	$4	0.1%	$0.02	$4	0.1%	(1.5%)
RTO Startup and Expansion	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Other	$0.00	$1	0.0%	$0.00	$0	0.0%	(50.5%)
Total Price	$28.18	$5,504	100.0%	$39.50	$8,171	100.0%	40.2%
Total Day Ahead Load	193,714			203,801			5.2%
Total Balancing Load	(1,616)			(3,034)			87.7%
Total Real Time Load	195,330			206,835			5.9%
Total Cost ($ Billions)	$5.50			$8.17			48.5%

55 US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (April 10, 2025).
56 The totals in the Transmission section of this table include corrections to previously reported totals which did not include a full accounting of Transmission Enhancement Cost Recovery costs.
57 Note: The totals in this table include after the fact billing adjustments and may not match totals presented in past reports.

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

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

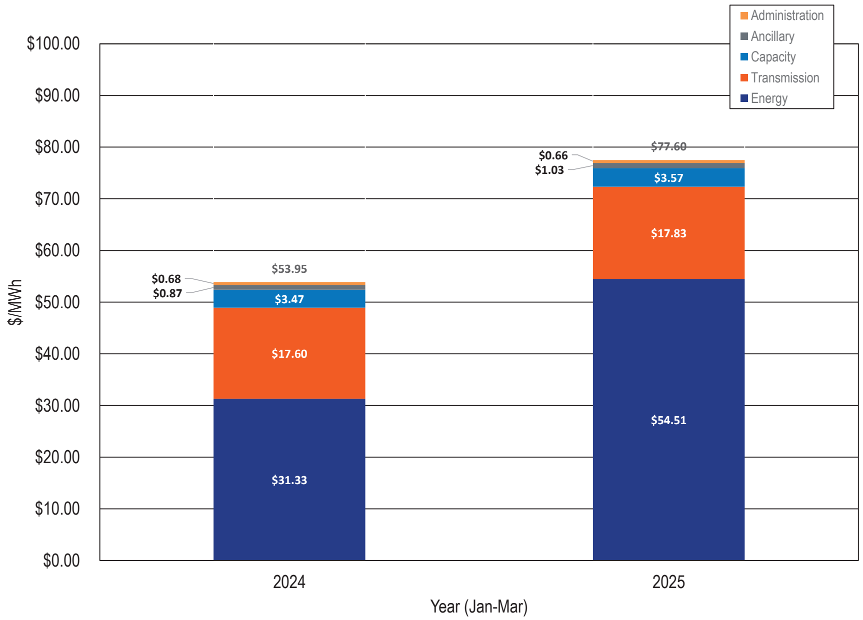
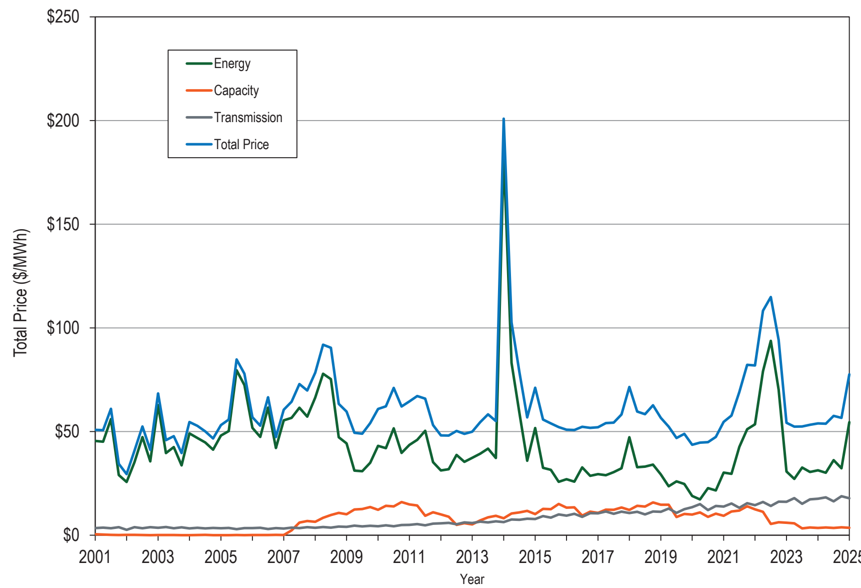


Figure 1-4 shows the contributions of the energy, capacity and transmission service components of the total cost of wholesale power for each quarter since 2001. Starting in the third quarter of 2019, the cost of transmission per MWh of wholesale power has been higher than the cost of capacity.

Figure 1-4 Top three components of quarterly total cost ($/MWh): January 2001 through March 2025[58]



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

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

Table 1-11 Total cost per MWh by category: 2001 through 2024[59]

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Category	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh
Energy	$44.41	$36.91	$44.97	$44.95	$63.89	$51.15	$57.76	$66.84	$35.47	$44.36	$44.06	$34.43	$38.94	$93.20	$35.96	$28.74	$30.29	$36.84	$25.99	$20.26	$38.44	$74.42	$30.40	$32.59
Day Ahead Energy	$39.66	$35.34	$41.72	$40.75	$60.21	$50.02	$57.04	$68.59	$37.78	$45.19	$44.29	$33.67	$37.88	$51.81	$36.52	$29.48	$30.92	$37.57	$27.15	$21.09	$38.65	$74.25	$31.58	$33.43
Balancing Energy	$4.46	$2.24	$3.49	$4.06	$3.85	$2.50	$3.05	$3.48	$1.80	$3.56	$2.06	$1.55	$1.83	$42.24	$0.81	$0.53	$0.34	$0.74	$0.17	$0.36	$0.80	$2.04	$0.45	$0.57
ARR Credits	$0.00	$0.00	($0.27)	($0.40)	($0.39)	($0.59)	($0.62)	($0.72)	($0.89)	($0.52)	($0.64)	($0.55)	($0.45)	($0.54)	($0.73)	($0.82)	($0.68)	($0.70)	($0.87)	($0.69)	($0.56)	($1.15)	($1.46)	($1.24)
Self Scheduled FTR Credits	($0.93)	($1.35)	($0.83)	($0.32)	($0.80)	($1.21)	($1.58)	($2.18)	($0.69)	($1.26)	($0.57)	($0.22)	($0.23)	($0.63)	($0.46)	($0.29)	($0.20)	($0.34)	($0.14)	($0.19)	($0.33)	($1.11)	($0.42)	($0.52)
Balancing Congestion	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.03	$0.09	$0.17	$0.18	$0.30	$0.67	$0.39	$0.39
Emergency Energy	$0.00	$0.00	$0.02	$0.00	$0.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.00	$0.00
Inadvertent Energy	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	($0.00)	($0.01)	$0.00	($0.02)	$0.04	$0.01	($0.01)	($0.01)	$0.00	($0.01)	$0.01	$0.01	($0.00)	$0.00	$0.00	($0.03)	$0.01	$0.01
Load Response - Energy	$0.00	$0.00	$0.00	$0.00	$0.00	$0.03	$0.06	$0.05	$0.00	$0.00	$0.00	$0.01	$0.01	$0.02	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.01	$0.01
Emergency Load Response	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.02	$0.02	$0.01	$0.06	$0.06	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.08	$0.00
Energy Uplift (Operating Reserves)	$1.26	$0.72	$0.89	$0.95	$1.07	$0.47	$0.65	$0.64	$0.48	$0.80	$0.78	$0.74	$0.55	$1.11	$0.38	$0.17	$0.14	$0.23	$0.11	$0.12	$0.23	$0.36	$0.21	$0.34
Marginal Loss Surplus Allocation	($0.05)	($0.04)	($0.05)	($0.09)	($0.10)	($0.07)	($0.86)	($3.07)	($3.06)	($3.47)	($2.03)	($0.86)	($0.73)	($0.93)	($0.63)	($0.37)	($0.35)	($0.88)	($0.65)	($0.68)	($0.70)	($0.87)	($0.51)	($0.45)
Market to Market Payments	$0.00	$0.00	$0.00	$0.00	$0.03	($0.00)	$0.02	$0.06	$0.05	$0.05	$0.10	$0.06	$0.03	$0.06	$0.05	$0.05	$0.07	$0.12	$0.05	$0.06	$0.04	$0.23	$0.07	$0.05
Capacity	$0.27	$0.12	$0.08	$0.09	$0.04	$0.11	$3.85	$8.83	$12.13	$14.04	$12.26	$7.36	$7.58	$10.29	$12.50	$11.78	$12.16	$13.95	$12.00	$9.99	$11.64	$8.81	$4.63	$3.61
Capacity (Capacity Market and FRR)	$0.27	$0.12	$0.08	$0.09	$0.03	$0.03	$3.80	$8.79	$12.12	$14.01	$12.12	$7.27	$7.52	$10.25	$12.50	$11.78	$12.12	$13.90	$11.98	$9.99	$11.64	$8.74	$4.53	$3.56
Capacity Part V (RMR)	$0.00	$0.00	$0.00	$0.00	$0.02	$0.08	$0.05	$0.04	$0.01	$0.02	$0.13	$0.08	$0.06	$0.04	($0.00)	($0.00)	$0.04	$0.05	$0.02	$0.00	$0.00	$0.07	$0.11	$0.04
Load Response - Capacity	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.00	$0.00	$0.00	$0.01	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01
Transmission	$3.56	$3.46	$3.64	$3.43	$3.30	$3.34	$3.55	$3.84	$4.36	$4.54	$5.15	$5.77	$6.29	$7.30	$8.81	$9.75	$10.92	$10.83	$11.79	$13.58	$14.37	$15.12	$16.54	$17.71
Transmission Service Charges	$3.48	$3.39	$3.57	$3.28	$2.71	$3.18	$3.45	$3.68	$4.03	$4.04	$4.49	$4.90	$5.21	$5.96	$7.09	$7.81	$8.83	$8.81	$9.80	$11.33	$12.00	$12.77	$14.13	$15.04
Transmission Enhancement Cost Recovery	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.07	$0.25	$0.40	$0.56	$0.78	$0.99	$1.25	$1.62	$1.86	$2.02	$1.92	$1.91	$2.15	$2.29	$2.28	$2.32	$2.57
Transmission Owner (Schedule 1A)	$0.08	$0.07	$0.07	$0.10	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.08	$0.08	$0.09	$0.09	$0.09	$0.10	$0.09	$0.09	$0.09	$0.09	$0.08	$0.08	$0.09
Transmission Seams Elimination Cost Assignment (SECA)	$0.00	$0.00	$0.00	$0.05	$0.50	$0.07	$0.00	$0.00	$0.00	$0.00	($0.00)	$0.00	$0.00	$0.00	$0.00	$0.00	($0.03)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Transmission Facility Charges	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.01	$0.01	($0.01)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Ancillary	$0.75	$0.63	$0.91	$0.91	$1.19	$0.92	$1.00	$1.15	$0.78	$0.90	$0.90	$0.84	$1.24	$0.99	$0.91	$0.71	$0.76	$0.79	$0.71	$0.72	$0.86	$1.08	$0.89	$0.92
Reactive	$0.22	$0.20	$0.24	$0.26	$0.26	$0.29	$0.29	$0.34	$0.36	$0.45	$0.41	$0.46	$0.76	$0.40	$0.37	$0.38	$0.42	$0.40	$0.43	$0.47	$0.48	$0.50	$0.52	$0.49
Regulation	$0.53	$0.42	$0.50	$0.51	$0.80	$0.53	$0.63	$0.70	$0.34	$0.36	$0.32	$0.26	$0.25	$0.33	$0.23	$0.11	$0.14	$0.18	$0.12	$0.10	$0.19	$0.38	$0.17	$0.23
Black Start	$0.00	$0.00	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.04	$0.14	$0.08	$0.08	$0.09	$0.09	$0.08	$0.08	$0.09	$0.09	$0.09	$0.09	$0.09
Synchronized Reserves	$0.00	$0.01	$0.15	$0.13	$0.11	$0.08	$0.06	$0.08	$0.05	$0.07	$0.09	$0.04	$0.04	$0.12	$0.11	$0.05	$0.06	$0.06	$0.04	$0.03	$0.07	$0.11	$0.10	$0.10
Secondary Reserves	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	($0.00)	$0.00	$0.00
Non-Synchronized Reserves	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.02	$0.02	$0.01	$0.01	$0.02	$0.02	$0.01	$0.02	($0.01)	$0.01	$0.01
Day Ahead Scheduling Reserve (DASR)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.00	$0.01	$0.05	$0.05	$0.06	$0.05	$0.10	$0.07	$0.05	$0.05	$0.02	$0.02	$0.01	$0.01	$0.00	$0.00
Administration	$0.74	$0.86	$1.09	$1.07	$0.77	$0.81	$0.83	$0.48	$0.35	$0.43	$0.40	$0.50	$0.44	$0.47	$0.47	$0.48	$0.53	$0.61	$0.61	$0.55	$0.55	$0.55	$0.62	$0.68
PJM Administrative Fees	$0.73	$0.86	$1.05	$0.93	$0.72	$0.74	$0.76	$0.43	$0.31	$0.36	$0.37	$0.46	$0.40	$0.43	$0.43	$0.44	$0.49	$0.57	$0.57	$0.50	$0.50	$0.50	$0.57	$0.63
NERC/RFC	$0.01	$0.01	$0.04	$0.07	$0.04	$0.05	$0.06	$0.04	$0.02	$0.02	$0.02	$0.02	$0.02	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.04	$0.04	$0.04	$0.04	$0.04
RTO Startup and Expansion	$0.00	$0.00	$0.00	$0.06	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Other	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.03	$0.00	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.00	$0.01	$0.01
Total Price	$49.73	$41.98	$50.69	$50.44	$69.19	$56.32	$66.98	$81.14	$53.10	$64.26	$62.76	$48.90	$54.49	$112.24	$58.65	$51.46	$54.66	$63.02	$51.10	$45.10	$65.87	$99.97	$53.08	$55.51
Total Day Ahead Load	292,717	344,235	324,653	413,294	654,505	672,501	691,547	676,030	644,485	656,928	704,581	745,165	753,865	749,927	773,842	774,730	760,624	784,553	771,055	734,641	755,824	765,499	748,619	775,838
Total Balancing Load	27,319	31,337	(2,879)	(25,580)	(30,087)	(23,664)	(23,977)	(22,429)	(21,584)	(40,463)	(18,519)	(19,136)	(19,925)	(30,578)	(2,251)	(3,538)	1,849	(6,542)	(874)	(8,346)	(11,602)	(13,126)	(6,433)	(8,345)
Total Real Time Load	265,398	312,899	327,533	438,874	684,592	696,165	715,524	698,459	666,069	697,391	723,101	764,300	773,790	780,505	776,093	778,269	758,775	791,094	771,929	742,987	767,425	778,624	755,053	784,182
Total Cost ($ Billions)	$13.20	$13.14	$16.60	$22.14	$47.37	$39.21	$47.93	$56.67	$35.37	$44.81	$45.38	$37.37	$42.17	$87.60	$45.52	$40.05	$41.47	$49.86	$39.45	$33.51	$50.55	$77.84	$40.08	$43.53

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

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

Table 1-12 Percent of total cost per MWh by category: 2001 through 2024[60]

Category	Percent of Total Charges 2001	Percent of Total Charges 2002	Percent of Total Charges 2003	Percent of Total Charges 2004	Percent of Total Charges 2005	Percent of Total Charges 2006	Percent of Total Charges 2007	Percent of Total Charges 2008	Percent of Total Charges 2009	Percent of Total Charges 2010	Percent of Total Charges 2011	Percent of Total Charges 2012	Percent of Total Charges 2013	Percent of Total Charges 2014	Percent of Total Charges 2015	Percent of Total Charges 2016	Percent of Total Charges 2017	Percent of Total Charges 2018	Percent of Total Charges 2019	Percent of Total Charges 2020	Percent of Total Charges 2021	Percent of Total Charges 2022	Percent of Total Charges 2023	Percent of Total Charges 2024
Energy	89.3%	87.9%	88.7%	89.1%	92.3%	90.8%	86.2%	82.4%	66.8%	69.0%	70.2%	70.4%	71.5%	83.0%	61.3%	55.8%	55.4%	58.5%	50.8%	44.9%	58.4%	74.4%	57.3%	58.7%
Day Ahead Energy	79.8%	84.2%	82.3%	80.8%	87.0%	88.8%	85.2%	84.5%	71.1%	70.3%	70.6%	68.9%	69.5%	46.2%	62.3%	57.3%	56.6%	59.6%	53.1%	46.8%	58.7%	74.3%	59.5%	60.2%
Balancing Energy	9.0%	5.3%	6.9%	8.1%	5.6%	4.4%	4.6%	4.3%	3.4%	5.5%	3.3%	3.2%	3.4%	37.6%	1.4%	1.0%	0.6%	1.2%	0.3%	0.8%	1.2%	2.0%	0.8%	1.0%
ARR Credits	0.0%	0.0%	(0.5%)	(0.8%)	(0.6%)	(1.0%)	(0.9%)	(0.9%)	(1.7%)	(0.8%)	(1.0%)	(1.1%)	(0.8%)	(0.5%)	(1.3%)	(1.6%)	(1.2%)	(1.1%)	(1.7%)	(1.5%)	(0.8%)	(1.2%)	(2.8%)	(2.2%)
Self Scheduled FTR Credits	(1.9%)	(3.2%)	(1.6%)	(0.6%)	(1.2%)	(2.1%)	(2.4%)	(2.7%)	(1.3%)	(2.0%)	(0.9%)	(0.5%)	(0.4%)	(0.6%)	(0.8%)	(0.6%)	(0.4%)	(0.5%)	(0.3%)	(0.4%)	(0.5%)	(1.1%)	(0.8%)	(0.9%)
Balancing Congestion	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.3%	0.4%	0.5%	0.7%	0.7%	0.7%
Emergency Energy	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Inadvertent Energy	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	(0.0%)	(0.0%)	0.0%	(0.0%)	0.1%	0.0%	(0.0%)	(0.0%)	0.0%	(0.0%)	0.0%	0.0%	(0.0%)	0.0%	0.0%	(0.0%)	0.0%	0.0%
Load Response - Energy	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Emergency Load Response	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%
Energy Uplift (Operating Reserves)	2.5%	1.7%	1.8%	1.9%	1.5%	0.8%	1.0%	0.8%	0.9%	1.2%	1.2%	1.5%	1.0%	1.0%	0.7%	0.3%	0.3%	0.4%	0.2%	0.3%	0.3%	0.4%	0.4%	0.6%
Marginal Loss Surplus Allocation	(0.1%)	(0.1%)	(0.1%)	(0.2%)	(0.1%)	(0.1%)	(1.3%)	(3.8%)	(5.8%)	(5.4%)	(3.2%)	(1.7%)	(1.3%)	(0.8%)	(1.1%)	(0.7%)	(0.6%)	(1.4%)	(1.3%)	(1.5%)	(1.1%)	(0.9%)	(1.0%)	(0.8%)
Market to Market Payments	0.0%	0.0%	0.0%	0.0%	0.0%	(0.0%)	0.0%	0.1%	0.1%	0.1%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.2%	0.1%	0.1%	0.1%	0.2%	0.1%	0.1%
Capacity	0.5%	0.3%	0.2%	0.2%	0.1%	0.2%	5.8%	10.9%	22.8%	21.8%	19.5%	15.1%	13.9%	9.2%	21.3%	22.9%	22.2%	22.1%	23.5%	22.1%	17.7%	8.8%	8.7%	6.5%
Capacity (Capacity Market and FRR)	0.5%	0.3%	0.2%	0.2%	0.0%	0.0%	5.7%	10.8%	22.8%	21.8%	19.3%	14.9%	13.8%	9.1%	21.3%	22.9%	22.2%	22.1%	23.4%	22.1%	17.7%	8.7%	8.5%	6.4%
Capacity Part V (RMR)	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.0%	0.0%	0.2%	0.2%	0.1%	0.0%	(0.0%)	(0.0%)	0.1%	0.1%	0.0%	0.0%	0.0%	0.1%	0.2%	0.1%
Load Response - Capacity	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Transmission	7.2%	8.2%	7.2%	6.8%	4.8%	5.9%	5.3%	4.7%	8.2%	7.1%	8.2%	11.8%	11.5%	6.5%	15.0%	18.9%	20.0%	17.2%	23.1%	30.1%	21.8%	15.1%	31.2%	31.9%
Transmission Service Charges	7.0%	8.1%	7.0%	6.5%	3.9%	5.7%	5.2%	4.5%	7.6%	6.3%	7.2%	10.0%	9.6%	5.3%	12.1%	15.2%	16.2%	14.0%	19.2%	25.1%	18.2%	12.8%	26.6%	27.1%
Transmission Enhancement Cost Recovery	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.5%	0.6%	0.9%	1.6%	1.8%	1.1%	2.8%	3.6%	3.7%	3.1%	3.7%	4.8%	3.5%	2.3%	4.4%	4.6%
Transmission Owner (Schedule 1A)	0.2%	0.2%	0.1%	0.2%	0.1%	0.2%	0.1%	0.1%	0.2%	0.1%	0.1%	0.2%	0.2%	0.1%	0.2%	0.2%	0.2%	0.1%	0.2%	0.2%	0.1%	0.1%	0.2%	0.2%
Transmission Seams Elimination Cost Assignment (SECA)	0.0%	0.0%	0.0%	0.1%	0.7%	0.1%	0.0%	0.0%	0.0%	0.0%	(0.0%)	0.0%	0.0%	0.0%	0.0%	0.0%	(0.0%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Transmission Facility Charges	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	(0.0%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Ancillary	1.5%	1.5%	1.8%	1.8%	1.7%	1.6%	1.5%	1.4%	1.5%	1.4%	1.4%	1.7%	2.3%	0.9%	1.6%	1.4%	1.4%	1.3%	1.4%	1.6%	1.3%	1.1%	1.7%	1.7%
Reactive	0.4%	0.5%	0.5%	0.5%	0.4%	0.5%	0.4%	0.4%	0.7%	0.7%	0.7%	0.9%	1.4%	0.4%	0.6%	0.7%	0.8%	0.6%	0.8%	1.0%	0.7%	0.5%	1.0%	0.9%
Regulation	1.1%	1.0%	1.0%	1.0%	1.2%	0.9%	0.9%	0.9%	0.6%	0.6%	0.5%	0.5%	0.5%	0.3%	0.4%	0.2%	0.3%	0.3%	0.2%	0.2%	0.3%	0.4%	0.3%	0.4%
Black Start	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.3%	0.1%	0.1%	0.2%	0.2%	0.1%	0.2%	0.2%	0.1%	0.1%	0.2%	0.2%
Synchronized Reserves	0.0%	0.0%	0.3%	0.3%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.2%	0.2%
Secondary Reserves	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	(0.0%)	0.0%	0.0%
Non-Synchronized Reserves	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	(0.0%)	0.0%	0.0%
Day Ahead Scheduling Reserve (DASR)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.0%	0.2%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Administration	1.5%	2.1%	2.1%	2.1%	1.1%	1.4%	1.2%	0.6%	0.7%	0.7%	0.6%	1.0%	0.8%	0.4%	0.8%	0.9%	1.0%	1.0%	1.2%	1.2%	0.8%	0.5%	1.2%	1.2%
PJM Administrative Fees	1.5%	2.0%	2.1%	1.8%	1.0%	1.3%	1.1%	0.5%	0.6%	0.6%	0.6%	0.9%	0.7%	0.4%	0.7%	0.9%	0.9%	0.9%	1.1%	1.1%	0.8%	0.5%	1.1%	1.1%
NERC/RFC	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.1%	0.1%
RTO Startup and Expansion	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Other	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total Price	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

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

Section Overviews

Overview: Section 3, Energy Market

Supply and Demand

Market Structure

- **Supply.** In the first three months of 2025, 605 MW of new resources were added in the energy market, and 410 MW of resources were retired.
- The real-time hourly on peak average offered supply in the first three months of 2025 increased by 4.8 percent, from the first three months of 2024, from 139,763 MWh to 146,494 MWh.
- The day-ahead hourly average offered supply in the first three months of 2025 increased by 0.1 percent, from the first three months of 2024, from 159,234 MWh to 159,317 MWh.
- The real-time hourly average cleared generation in the first three months of 2025 increased by 6.4 percent from the first three months of 2024, from 95,999 MWh to 102,126 MWh.
- The day-ahead hourly average cleared supply in the first three months of 2025, including INCs and UTCs, increased by 3.0 percent from the first three months of 2024 from 114,088 MWh to 117,543 MWh.
- **Demand.** The real-time hourly peak load plus exports in the first three months of 2025 was 150,646 MWh (140,043 MWh of load plus 10,603 MWh of gross exports) in the HE 900 (EPT) on January 22, 2025, which was 5.5 percent, 7,825 MWh, higher than the PJM peak load plus exports in the first three months of 2024, which was 142,821 MWh in the HE 900 (EPT) on January 17, 2024.
- The real-time hourly peak load without exports in the first three months of 2025 was 140,043 MWh in the HE 900 (EPT) on January 22, 2025, higher than the PJM peak load in the first three months of 2024, which was 130,293 MWh in the HE 900 (EPT) on January 17, 2024.
- The real-time hourly average load in the first three months of 2025 increased by 7.1 percent from the first three months of 2024, from 89,478 MWh to 95,801 MWh.
- The day-ahead hourly average cleared demand in the first three months of 2025, including DECs and UTCs, increased by 2.7 percent from the first three months of 2024, from 107,798 MWh to 110,656 MWh.

Market Behavior

- **Virtual Offers and Bids.** Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids, up to congestion transactions, import transactions and export transactions as financial instruments that do not require physical generation or load. The hourly average submitted increment offer MW increased by 6.8 percent and the cleared increment MW increased by 12.6 percent in the first three months of 2025 compared to the first three months of 2024. The hourly average submitted decrement bid MW increased by 24.6 percent and the cleared decrement MW decreased by 4.0 percent in the first three months of 2025 compared to the first three months of 2024. The hourly average submitted up to congestion bid MW increased by 1.1 percent and the cleared up to congestion bid MW decreased by 18.9 percent in the first three months of 2025 compared to the first three months of 2024.

Market Performance

- **Generation Fuel Mix.** In the first three months of 2025, generation from coal units increased 31.3 percent, generation from natural gas units decreased 0.8 percent, generation from oil units increased 91.8 percent, generation from wind units increased 12.6 percent, and generation from solar units increased 61.8 percent compared to the first three months of 2024.
- **Fuel Diversity.** The fuel diversity of energy generation in the first three months of 2025, measured by the fuel diversity index for energy (FDI_e), increased 3.2 percent compared to the first three months of 2024.
- **Marginal Resources.** In the PJM Real-Time Energy Market in the first three months of 2025, coal units were 8.1 percent and natural gas units were 71.1 percent of marginal resources. In the first three months of 2024, coal units were 8.9 percent and natural gas units were 72.6 percent of marginal resources.

- **Prices.** The real-time load-weighted average LMP in the first three months of 2025 increased $21.19 per MWh, or 68.3 percent from the first three months of 2024, from $31.01 per MWh to $52.20 per MWh.
- The day-ahead load-weighted average LMP for the first three months of 2025 increased $21.26 or 65.7 percent from the first three months of 2024, from $32.34 per MWh to $53.60 per MWh.
- **Fast Start Pricing.** The real-time load-weighted average PLMP was $52.20 per MWh for the first three months of 2025, which is 6.6 percent, $3.25 per MWh, higher than the real-time load-weighted average DLMP of $48.95 per MWh.
- **Components of Real-Time LMP.** In the PJM Real-Time Energy Market in the first three months of 2025, 7.8 percent of the real-time load-weighted LMP was the result of coal costs, 56.6 percent was the result of gas costs, 3.3 percent was the result of the cost of emission allowances, and 7.7 percent was the result of transmission constraint violation penalty factors.
- **Changes in Real-Time LMP.** Of the $21.19 per MWh increase in the real-time load-weighted average LMP, $15.85 per MWh (74.8 percent) was the fuel and consumables cost components of LMP, -$0.32 per MWh (-1.5 percent) was the emissions cost components of LMP, 1.83 per MWh (8.6 percent) was the sum of the markup, maintenance, and ten percent adder components of LMP, $2.43 per MWh (11.4 percent) was the transmission constraint penalty factor component of LMP, and -$0.22 per MWh (-1.0 percent) was the scarcity component of LMP.
- **Price Convergence.** Hourly and daily price differences between the day-ahead and real-time energy markets fluctuate continuously and substantially from positive to negative. The average difference between day-ahead and real-time average prices was -$1.10 per MWh in the first three months of 2024, and -$1.07 per MWh in the first three months of 2024. The difference between day-ahead and real-time average prices, by itself, is not a measure of the competitiveness or effectiveness of the day-ahead energy market.

Scarcity

- **Shortage Intervals.** There were 14 intervals with five minute shortage pricing on six days in the first three months of 2024. These shortages did not correspond with any emergency warning or action. One of the 14 intervals of shortage occurred during a synchronized reserve event.
- **SCED Shortage Intervals.** In the first three months of 2025, there were 1,280 five minute intervals, or 4.9 percent of all five minute intervals, for which at least one RT SCED solution showed a shortage of reserves and there were 386 five minute intervals, or 1.5 percent of all five minute intervals, for which more than one RT SCED solution showed a shortage of reserves. In the first three months of 2025, PJM triggered shortage pricing for 14 five minute intervals, or 0.05 percent of all five minute intervals.

Competitive Assessment

Market Structure

- **Aggregate Pivotal Suppliers.** The PJM energy market, at times, requires generation from pivotal suppliers to meet load, resulting in aggregate market power even when the HHI level indicates that the aggregate market is unconcentrated. Three suppliers were jointly pivotal in the day-ahead market on 79 days, 87.8 percent of the days, in the first three months of 2025 and 22 days, 24.2 percent of the days, in the first three months of 2024.
- **Local Market Power.** In the first three months of 2025, in the real-time market, the 500 kV system, nine zones, and the PJM/MISO interface experienced congestion resulting from one or more constraints binding for 25 or more hours. For seven out of the top 10 congested facilities (by real-time binding hours) in the first three months of 2025, the average number of suppliers providing constraint relief was three or fewer. There was a high level of concentration within the local markets for providing relief to the most congested facilities in the PJM Real-Time Energy Market. The local market structure was not competitive.

Market Behavior

- **Offer Capping for Local Market Power.** PJM offer caps units when the local market structure is noncompetitive. Offer capping is an effective means of addressing local market power when the rules are designed and implemented properly. Offer capping levels have historically been low in PJM. In the day-ahead energy market, for units committed to provide energy for local constraint relief, offer-capped unit hours increased from 1.3 percent in the first three months of 2024 to 1.9 percent in the first three months of 2025. In the real-time energy market, for units committed to provide energy for local constraint relief, offer-capped unit hours increased from 0.3 percent in the first three months of 2024 to 1.4 percent in the first three months of 2025. While overall offer capping levels have been low, there are a significant number of units with persistent structural local market power that would have had a significant impact on prices in the absence of local market power mitigation.

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

- **Offer Capping for Reliability.** PJM also offer caps units that are committed for reliability reasons, including for reactive support. In the day-ahead energy market, for units committed for reliability reasons, offer-capped unit hours increased from 0.09 percent in the first three months of 2024 to 0.17 percent in the first three months of 2025. In the real-time energy market, for units committed for reliability reasons, offer-capped unit hours increased from 0.01 percent in the first three months of 2024 to 0.13 percent in the first three months of 2025. The low offer cap percentages for reliability commitments, relative to offer capping for transmission constraints, do not mean that units committed for reliability reasons do not have market power. All units manually committed for reliability have market power and all are treated consistent with that fact.

- **Parameter Mitigation.** In the first three months of 2025, 24.2 percent of unit hours for units that failed the TPS test in the day-ahead market were committed on price-based schedules that were less flexible than their cost-based schedules. On days when cold weather alerts and hot weather alerts were declared, 38.5 percent of unit hours in the day-ahead energy market were committed on price-based schedules that were less flexible than their price PLS schedules.

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

- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. While the average markup index in the real-time market was -0.06 when using unadjusted cost-based offers in the first three months of 2025, some marginal units did have substantial markups. The highest markup for any marginal unit in the real-time market in the first three months of 2025 was more than $800 per MWh, using unadjusted cost-based offers.

- While the average markup index in the day-ahead market was $0.08 per MWh in the first three months of 2025, some marginal units did have substantial markups. The highest markup for any marginal unit in the day-ahead market in the first three months of 2025 was more than $150 per MWh and the highest markup in the first three months of 2024 was more than $100 per MWh.

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

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

Market Performance

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

  In the PJM Real-Time Energy Market in the first three months of 2025, the unadjusted markup component (net of positive and negative markup components) of LMP was -$0.95 per MWh or -1.8 percent of the PJM load-weighted average LMP. February had the highest unadjusted peak markup component, -$0.22 per MWh, or -1.1 percent of the real-time peak hour load-weighted average LMP for February.

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

- **Markup and Local Market Power.** Comparison of the markup behavior of marginal units with TPS test results shows that for 1.9 percent of all real-time marginal unit intervals in the first three months of 2025, the marginal unit had both local market power as determined by the TPS test and a positive markup. The fact that units with market power had a positive markup means that the cost-based offer was not used, that a higher price-based offer was used, and that the process for offer capping units that fail the TPS test does not consistently result in competitive market outcomes in the presence of market power.

- **Markup and Aggregate Market Power.** In the first three months of 2025, pivotal suppliers in the aggregate market, committed in the day-ahead market and identified as one of three day-ahead aggregate pivotal suppliers, set real-time market prices with markups over $100 per MWh on 43 days. Some of the marginal units had local market power, but were not offer capped due to issues with the method that PJM uses to select offer schedules for units that fail the TPS test. Some of the marginal units had aggregate market power, for which there is no offer capping, and some had both local and aggregate market power.

Section 3 Recommendations

Market Power

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

Fuel Cost Policies

- The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic, and accurately reflect short run marginal costs. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that the temporary cost method be removed and that all units that submit nonzero cost-based offers be required to have an approved fuel cost policy. (Priority: Low. First reported 2020. Status: Not adopted.)
- The MMU recommends that the penalty exemption provision be removed and that all units that submit nonzero cost-based offers be required to follow their approved fuel cost policy. (Priority: Medium. First reported 2020. Status: Not adopted.)

Cost-Based Offers

- The MMU recommends that Manual 15 (Cost Development Guidelines) be replaced or updated with a straightforward description of the components of cost-based offers and the mathematically correct calculation of cost-based offers for thermal resources. (Priority: Medium. First reported 2016. Status: Adopted 2023.)
- The MMU recommends removal of all use of FERC System of Accounts in the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)

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

Market Power: TPS Test and Offer Capping

- The MMU recommends that the rules governing the application of the TPS test be clarified and documented. The TPS test application in the day-ahead energy market is not documented. (Priority: High. First reported 2015. Status: Partially adopted.)[61]
- The MMU recommends that PJM modify the process of applying the TPS test in the day-ahead energy market to ensure that all local markets created by binding constraints are tested for market power and to ensure that market sellers with market power are appropriately mitigated to their competitive offers. (Priority: High. First reported 2022. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that offer capping be applied to units that fail the TPS test in the real-time market that were not offer capped at the time of commitment in the day-ahead market or at a prior time in the real-time market. (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation and to ensure that capacity resources meet their obligations to be flexible, that capacity resources be required to use flexible parameters in all offers at all times. (Priority: High. First reported 2021. Status: Not adopted.)

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

- The MMU recommends, in order to ensure effective market power mitigation, PJM always use cost-based offers for units that fail the TPS test, and always use flexible parameters for all cost-based and all price-based offers during high load conditions such as cold and hot weather alerts and emergency conditions. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM require every market participant to make available at least one cost schedule based on the same hourly fuel type(s) and parameters at least as flexible as their offered price schedule. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that markup be consistently positive or negative across the full MWh range of price and cost-based offers. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation, that PJM commit all resources that fail the TPS test on their cost-based offers, that the Market Seller designate the cost-based offer if there is more than one, and that PJM implement this solution as soon as possible. (Priority: High. First reported Q3 2024. Status: Not adopted.)
- The MMU recommends that PJM retain the $1,000 per MWh offer cap in the PJM energy market except when cost-based offers exceed $1,000 per MWh, and retain other existing rules that limit incentives to exercise market power. (Priority: High. First reported 1999. Status: Partially adopted, 1999, 2017.)
- The MMU recommends the elimination of FMU and AU adders. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets. (Priority: Medium. First reported 2012. Status: Partially adopted, 2014.)[62]

Offer Behavior

- The MMU recommends that resources not be allowed to violate the ICAP must offer requirement. The MMU recommends that PJM enforce the ICAP must offer requirement by assigning a forced outage to any unit that is derated in the energy market below its committed ICAP without an outage that reflects the derate. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that intermittent resources be subject to an enforceable ICAP must offer rule in the day-ahead and real-time energy markets that reflects the limitations of these resources. (Priority: Medium. First reported 2020. Status: Adopted 2023.)
- The MMU recommends that storage resources be subject to an enforceable ICAP must offer rule in the day-ahead and real-time energy markets that reflects the limitations of these resources. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that capacity resources not be allowed to offer any portion of their capacity market obligation as maximum emergency energy. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM integrate all the outage reporting tools in order to enforce the ICAP must offer requirement, ensure that outages are reported correctly and eliminate reporting inconsistencies. Generators currently submit availability in three different tools that are not integrated, Markets Gateway, eDART and eGADS. (Priority: Medium. First reported 2022. Status: Not adopted.)
- The MMU recommends that gas generators be required to check with pipelines throughout the operating day to confirm that nominations are accepted beyond the NAESB deadlines, that gas generators be required to inform PJM about whether they have gas, and that gas generators be required to place their units on forced outage until the time that pipelines allow nominations to consume gas at a unit. (Priority: Medium. First reported 2022. Status: Not adopted.)

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

Capacity Resources

- The MMU recommends that capacity resources be held to the OEM operating parameters of the capacity market CONE reference resource for performance assessment and energy uplift payments and that this standard be applied to all technologies on a uniform basis. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that the parameters which determine nonperformance charges and the amounts of uplift payments should reflect the flexibility goals of the capacity market design. The operational parameters used by generation owners to indicate to PJM operators what a unit is capable of during the operating day should not determine capacity resource performance assessment or uplift payments. (Priority: Medium. First reported 2015. Status: Partially adopted.)[63]
- The MMU recommends that PJM clearly define the business rules that apply to the unit specific parameter adjustment process, including PJM's implementation of the tariff rules in the PJM manuals to ensure market sellers know the requirements for their resources. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM update the tariff to clarify that all generation resources are subject to unit specific parameter limits on their cost-based offers using the same standard and process as capacity resources. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that resources not be paid the daily capacity payment when unable to operate to their unit specific parameter limits. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM not approve temporary exceptions that are based on pipeline tariff terms that are not enforced at the time, or are based on inferior transportation service procured by the generator. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM require generators that violate their approved turn down ratio (by either using the fixed gen option or increasing their economic minimum) to use the temporary parameter exception process that requires market sellers to demonstrate that the request is based on a physical and actual constraint. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends: that gas generators be required to confirm, regularly during the operating day, that they can obtain gas if requested to operate at their economic maximum level; that gas generators provide that information to PJM during the operating day; and that gas generators be required to be on forced outage if they cannot obtain gas during the operating day to meet their must offer requirement as a result of pipeline restrictions, and they do not have backup fuel. As part of this, the MMU recommends that PJM collect data on each individual generator's fuel supply arrangements at least annually or when such arrangements change, and analyze the associated locational and regional risks to reliability. (Priority: Medium. First reported 2022. Status: Not adopted.)
- The MMU recommends, if the capacity market seller offer cap were to be calculated using the historical average balancing ratio, that PJM not include the balancing ratios calculated for localized Performance Assessment Intervals (PAIs), and only include those events that trigger emergencies at a defined zonal or higher level. (Priority: Medium. First reported 2018. Status: Adopted, 2023.[64])

Accurate System Modeling

- The MMU recommends that PJM explicitly state its policy on the use of transmission penalty factors including: the level of the penalty factors; the triggers for the use of the penalty factors; the appropriate line ratings to trigger the use of penalty factors; the allowed duration of the violation and when the transmission penalty factors will be used to set the shadow price. The MMU recommends that PJM end the practice of manual and automated discretionary reductions in the control limits on transmission constraint line ratings used in the market clearing software (SCED) and included in LMP. (Priority: Medium. First reported 2015. Status: Partially adopted 2020.)[65]

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

64 See 184 FERC ¶ 61,058 (2023).

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

- The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission system are accurate and reflect standard ratings practice. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM not use closed loop interface or surrogate constraints to artificially override nodal prices based on fundamental LMP logic in order to: accommodate rather than resolve the inadequacies of the demand side resource capacity product; address the inability of the power flow model to incorporate the need for reactive power; accommodate rather than resolve the flaws in PJM's approach to scarcity pricing; or for any other reason. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM update the outage impact studies, the reliability analyses used in RPM for capacity deliverability, and the reliability analyses used in RTEP for transmission upgrades to be consistent with the more conservative emergency operations (post contingency load dump limit exceedance analysis) in the energy market that were implemented in June 2013.[66] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM include in the tariff or appropriate manual an explanation of the initial creation of hubs, the process for modifying hub definitions and a description of how hub definitions have changed.[67] [68] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that all buses with a net withdrawal be treated as load for purposes of calculating load and load-weighted LMP, even if the MW are settled to the generator. The MMU recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load-weighted LMP, even if the injection MW are settled to the load serving entity. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM document how LMPs are calculated when demand response is marginal. (Priority: Low. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM not allow nuclear generators which do not respond to prices or which only respond to manual instructions from the operator to set the LMPs in the real-time market. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM increase the coordination of outage and operational restrictions data submitted by market participants via eDART/eGADs and offer data submitted via Markets Gateway. (Priority: Low. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM model generators' operating transitions, including soak time for units with a steam turbine, configuration transitions for combined cycles, and peak operating modes. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM clarify, modify and document its process for dispatching reserves and energy when SCED indicates that supply is less than total demand including forecasted load and reserve requirements. The modifications should define: a SCED process to economically convert reserves to energy; a process for the recall of energy from capacity resources; and the minimum level of synchronized reserves that would trigger load shedding. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that PJM stop capping the system marginal price in RT SCED and LPC and instead limit the sum of violated reserve constraint shadow prices that are included in the determination of LMP in LPC to $1,700 per MWh. While PJM no longer caps prices in RT SCED,

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

PJM continues to apply a cap to the system marginal price in the pricing run (LPC) under fast start pricing. (Priority: Medium. First reported 2021. Status: Not adopted.)

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

Transparency

- The MMU recommends that PJM clearly document the calculation of shortage prices and implementation of reserve price caps in the PJM manuals, including defining all the components of reserve prices, and all the constraints whose shadow prices are included in reserve prices. (Priority: High. First reported 2021. Status: Not adopted.)
- The MMU recommends that PJM allow generators to report fuel type on an hourly basis in their offer schedules and to designate schedule availability on an hourly basis. (Priority: Medium. First reported 2015. Status: Partially adopted.)[69]
- The MMU recommends that PJM define clear criteria for operator approval of RT SCED cases, including shortage cases, that are used to send dispatch signals to resources, and for pricing, to minimize discretion. (Priority: High. First reported 2018. Status: Partially adopted.)[70]

Virtual Bids and Offers

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

69 Fuel type is reported by offer schedule, but it can be inaccurate on an hourly basis.

70 The PJM Market Rules clarify that shortage case approval will be based on RT SCED, but does not address RT SCED case choice or load bias.

Section 3 Conclusion

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

Prices are a key outcome of markets. Prices vary across hours, days and years for multiple reasons. Price is an indicator of the level of competition in a market. In a competitive market, prices are directly related to input prices, the marginal cost to serve load. In the first three months of 2025, LMP increased by $21.99 per MWh compared to the first three months of 2024. The fuel cost components of LMP (the sum of gas, coal, oil, landfill gas, and consumables) increased $15.85 per MWh, 74.8 percent of the increase in LMP. The emissions cost components of LMP, including opportunity costs for emissions limited resources, decreased by $0.32 per MWh, -1.5 percent of the increase in LMP. The transmission constraint penalty factor component increased by $2.43 per MWh, 11.4 percent of the increase in LMP, primarily as a result of PJM actions to reduce the line limits applied in SCED (control limits) below the actual line limits.

The pattern of prices within days and across months and years illustrates how prices are directly related to supply and demand conditions and illustrates the potential significance of the impact of the price elasticity of demand on prices. Energy market results in the first three months of 2025 generally reflected supply-demand fundamentals, although the behavior of some participants both routinely and during high demand periods represents economic withholding. Economic withholding occurs when generator offers are greater than competitive levels. In the first three months of 2025, the sum of the markup, ten percent adder, and maintenance cost (not short run marginal cost) components increased by $1.83 per MWh or 8.6 percent of the increase in LMP.

The potential for prolonged and excessively high administrative pricing in the energy market due to reserve penalty factors and transmission constraint penalty factors remains an issue that needs to be addressed.[71] There also continue to be significant issues with PJM's scarcity pricing rules, including the absence of a clear trigger based on accurately estimated reserve levels. For example, PJM approved 2.5 percent of solved shortage cases in January 2024, but only 0.6 percent for the year. Six other months had a higher percent of shortage cases solved, but fewer approved. The pattern of shortage case approvals indicates that PJM considers factors that are not documented in the tariff when deciding whether to approve shortage cases. As directed by FERC Order 825, PJM should approve shortage cases based on market software results alone.[72]

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

PJM defined inputs to the dispatch tools, particularly RT SCED, have substantial effects on energy market outcomes. Transmission line ratings, transmission penalty factors, load forecast bias, and hydro resource schedules change the dispatch of the system, affect prices, and can create significant price increases, particularly through transmission constraint penalty factors. PJM operator interventions to reduce the control limits on transmission constraint line ratings in RT SCED unnecessarily trigger transmission constraint penalty factors and significantly increase prices. In the first three months of 2025, the control limit used in RT SCED for 92 percent of violated transmission constraint intervals was less than 100 percent of the actual line limit, with an average reduction of 5.9 percent. If the control limits had not been artificially reduced for PJM transmission constraints and everything else remained unchanged, the transmission penalty factor's contribution to the load weighted average LMP in the first three months of 2025 would have decreased by 99.3 percent from $4.03 to $0.03 per MWh. PJM should evaluate its interventions in the market, including the unnecessary imposition of transmission constraint penalty factors, reconsider whether the interventions are appropriate, and provide greater transparency to enhance market efficiency.

Fast start pricing, implemented on September 1, 2021, has disconnected pricing from dispatch instructions and despite the stated goal of reducing overall uplift, created a greater reliance on uplift rather than price as an incentive to follow PJM's instructions. The objective of efficient short run price signals is to minimize system production costs, not to minimize uplift. Repricing the market to reflect commitment costs using fast start pricing prioritizes minimizing uplift over minimizing production costs.[73] The tradeoff exists because when commitment costs are included in prices, the price signal no longer equals the short run marginal cost and therefore no longer provides the correct signal for efficient behavior for market participants making decisions on the margin, whether resources, load, interchange transactions, or virtual traders. Units that start in one hour are not actually fast start units, and their commitment costs are not marginal in a five minute market. The differences between the actual LMP and the fast start LMP distort the incentive for market participants to behave competitively and to follow PJM's dispatch instructions. PJM is paying uplift in an attempt to counter the distorted incentives inherent in fast start pricing. PJM is also using the pricing run to implement administrative

71 177 FERC ¶ 61,209 (2021).
72 155 FERC ¶ 61,276 (2016).
73 See 173 FERC ¶ 61,244 (2020).

pricing rules that are not related to fast start pricing. Specifically, PJM uses lower transmission constraint penalty factors in the day-ahead pricing run than in the dispatch run and implements system marginal price capping in the pricing run. Every difference between the dispatch run and the pricing run introduces another inefficiency in the market. In the four years since fast start pricing was introduced, the market has not responded with new entry of fast start units despite consistently higher LMPs when a fast start unit sets price.

PJM's arguments for changing energy market price formation asserted that fast start pricing and PJM's rejected extended ORDC would price flexibility in the market, but instead they benefit inflexible units. The fast start pricing and extended ORDC solutions undercut LMP logic rather than directly addressing the underlying issues. The solution is not to accept that the inflexible CT should be paid or set price based on its commitment costs rather than its short run marginal costs. The question of why units make inflexible offers should be addressed directly. Are units inflexible because they are old and inefficient, because owners have not invested in increased flexibility or because they serve as a mechanism for the exercise of market power? Are units inflexible because the PJM software does not model combined cycle transitions? The question of how to provide market incentives for investment in flexible units, for investment in increased flexibility of existing units, and for operating at the full extent of existing flexibility should be addressed directly. The question of whether inflexible units should be paid uplift at all should be addressed directly. Marginal cost pricing without paying excess uplift to inflexible units would create incentives for market participants to provide flexible solutions including replacing inefficient units with flexible, efficient units.

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

The three pivotal supplier test is applied by PJM on an ongoing basis for local energy markets in order to determine whether offer capping is required for transmission constraints.[74] However, there are issues with the application of market power mitigation in the day-ahead energy market and the real-time energy market when market sellers fail the TPS test. The Commission recognized some of these issues in its order issued on June 17, 2021, but failed to address them in its November 30, 2023 order.[75] [76] PJM continued to ignore the evidence cited by the Commission and denies the prevalence of these issues, instead of ensuring that market power mitigation works as intended and results in efficient market outcomes.[77] Many of these issues can be resolved by simple rule changes. The MMU proposed these rule changes in its response submitted on October 15, 2021, and in the stakeholder

74 The MMU reviews PJM's application of the TPS test and brings issues to the attention of PJM.
75 See 175 FERC ¶ 61,231 (2021).
76 185 FERC ¶ 61,158 (2023).
77 See Answer of PJM Interconnection L.L.C., Docket No. EL21-78-000 (September 15, 2021).

process.[78] [79] The MMU recommendations would shorten the solution time of the day-ahead market software, which would help facilitate enhanced combined cycle modelling. The proposal that PJM filed with FERC on March 1, 2024, would have weakened market power mitigation as part of implementing the enhanced combined cycle modelling project, although PJM failed to explain why such weakening makes sense. PJM's proposal would have ensured that the identified issues with the implementation of market power mitigation in the energy market would never have been addressed and would have been exacerbated. On April 30, 2024, FERC rejected PJM's proposal because "PJM's proposal would create the ability for Market Sellers to exercise market power, which the Commission has found unjust and unreasonable."[80] PJM filed and, on October 25, 2024, FERC accepted a revised proposal that would require that sellers that fail the TPS test will be offer capped at their cost-based offers and that operating parameters will be mitigated. That order has no current effect because FERC approved the PJM filing that linked, for no logical reason, implementing the improved rules to PJM's adoption of an improved combined cycle model with no defined date. The flawed rules remain in place. PJM's proposal also uses the flawed formula rejected by FERC to select among cost-based offers. This will result in the illogical selection of cost-based offers in some circumstances, particularly if a dual fuel unit submits offers for both oil and gas on a day when the economics change between the two fuels midday. PJM should modify its implementation to address that issue. The result would allow market sellers to select the correct cost-based fuel schedule. There is no reason to delay implementation until PJM addresses combined cycle modelling. The changes would decrease the solution time for the day-ahead market and enhance market efficiency. The new approach, modified to correct the cost offer selection issue, should be implemented as soon as possible to help ensure effective market power mitigation.

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

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

78 *See* "Comments of the Independent Market Monitor for PJM," Docket No. EL21-78 (October 15, 2021).

79 *See* "Schedule Selection Proposal," MMU presentation to the Markets and Reliability Committee (October 25, 2023), <https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_MRC_Schedule_Selection_20231025.pdf>; "Schedule Selection: IMM Package," MMU Presentation to the Market Implementation Committee (September 6, 2023), <https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_MIC_Schedule_Selection_IMM_Package_20230906.pdf>; "Schedule Selection: IMM Proposal," MMU Presentation to the Market Implementation Committee (August 9, 2023), <https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_MIC_Schedule_Selection_IMM_Proposal_20230809.pdf>; "Least Cost Schedule Analysis," MMU Presentation at the MIC Special Session (July 17, 2023), <https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_MIC_Special_Session_Least_Cost_Schedule_Analysis_20230717.pdf>; "Multischedule Model and Mitigation: IMM Package," MMU Presentation to the MIC Special Session (May 24, 2023), <https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_MIC_Multischedule_Model_and_Mitigation_IMM_Package_20230524.pdf>; "Education: Schedule Selection and Market Power Mitigation," MMU Presentation to the MIC Special Session (March 29, 2023), <https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_MIC_Special_Session_Education_Schedule_%20Selection_and_Market_Power_Mitigation_20230330.pdf>; "Offer Schedule Selection," MMU Presentation to the Market Implementation Committee (February 8 2023), <https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_MIC_Offer_Schedule_Selection_20230208.pdf>.

80 187 FERC 61,051 at P 25 (2024).

for implementing an aggregate market power test and correcting the offer capping process for resources with local market power. The MMU concludes that the PJM energy market results were competitive in the first three months of 2025.

Overview: Section 4, Energy Uplift

Energy Uplift Credits

- **Energy uplift credits.** Total energy uplift credits increased by $385.3 million, or 498.4 percent, in the first three months of 2025 compared to the first three months of 2024, from $76.3 million to $462.7 million.
- **Types of energy uplift credits.** In the first three months of 2025, total energy uplift credits included $162.5 million in day-ahead generator credits, $288.9 million in balancing generator credits, $9.7 million in lost opportunity cost credits. Dispatch differential lost opportunity credits, which are a subset of balancing operating reserves, were implemented as part of fast start pricing on September 1, 2021, and were $1.1 million in the first three months of 2025.
- **Types of units.** In the first three months of 2025, steam coal units received 8.5 percent of day-ahead generator credits, and combustion turbines received 45.5 percent of balancing generator credits and 33.3 percent of lost opportunity cost credits. Combined cycle units and combustion turbines received 26.7 percent of dispatch differential lost opportunity credits, and hydro units received 64.3 percent of dispatch differential lost opportunity credits
- **Concentration of energy uplift credits.** In the first three months of 2025, the top 10 units receiving energy uplift credits received 44.3 percent of all credits and the top 10 organizations received 73.9 percent of all credits.
- **Lost opportunity cost credits.** Lost opportunity cost credits increased by $5.9 million, or 159.0 percent, in the first three months of 2025, compared to the first three months of 2024, from $3.7 million to $9.7million.

  Some combustion turbines and diesels are scheduled day-ahead but not requested in real time, and receive day-ahead lost opportunity cost credits as a result. This was the source of 90.3 percent of the $3.7 million of lost opportunity costs.
- **Following dispatch.** Some units are incorrectly paid uplift despite not meeting uplift eligibility requirements, including not following dispatch, not having the correct commitment status, or not operating with PLS offer parameters. Since 2018, the MMU has made cumulative resettlement requests for the most extreme overpaid units of $17.9 million, of which PJM has resettled only $3.9 million, or 22.0 percent.

Energy Uplift Charges

- **Energy Uplift Charges.** In the first three months of 2025, total energy uplift charges increased by $385.3 million, or 498.4 percent, compared to the first three months of 2024, from $77.3 million to $462.6 million.
- **Types of Energy Uplift Charges.** In the first three months of 2025, total uplift charges included $162.5 million in day-ahead operating reserve charges, $299.5 million in balancing generator charges, $0.5 million in reactive charges, and less than $0.1 million in black start services.

Section 4 Recommendations

- The MMU recommends that uplift be paid only based on operating parameters that reflect the flexibility of the benchmark new entrant unit (CONE unit) in the PJM Capacity Market. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM not pay uplift to units not following dispatch, including uplift related to fast start pricing, and require refunds where it has made such payments. This includes units whose offers are flagged for fixed generation in Markets Gateway because such units are not dispatchable. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM pay uplift based on the offer at the lower of the actual unit output or the dispatch signal MW. (Priority: Medium. First reported 2018. Status: Not adopted.)

- The MMU recommends eliminating intraday segments from the calculation of uplift payments and returning to calculating the need for uplift based on the entire 24 hour operating day. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends the elimination of day-ahead uplift to ensure that units receive an energy uplift payment based on their real-time output and not their day-ahead scheduled output. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that units not be paid lost opportunity cost uplift credits when PJM directs a unit to reduce output based on a transmission constraint or other reliability issue. There is no lost opportunity because the unit is required to reduce for the reliability of the unit and the system. (Priority: High. First reported 2021. Status: Not adopted.)
- The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing generator credits. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that self scheduled units not be paid energy uplift credits for their startup cost when the units are scheduled by PJM to start before the self scheduled hours. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends three modifications to the energy lost opportunity cost calculations:
- The MMU recommends calculating LOC based on 24 hour daily periods for combustion turbines and diesels scheduled in the day-ahead energy market, but not committed in real time. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that units scheduled in the day-ahead energy market and not committed in real time should be compensated for LOC based on their real-time desired and achievable output, not their scheduled day-ahead output. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that only flexible fast start units (startup plus notification times of 10 minutes or less) and units with short minimum run times (one hour or less) be eligible by default for the LOC compensation to units scheduled in the day-ahead energy market and not committed in real time. Other units should be eligible for LOC compensation only if PJM explicitly cancels their day-ahead commitment. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that up to congestion (UTC) transactions be required to pay energy uplift charges for both the injection and the withdrawal sides of the UTC. (Priority: High. First reported 2011. Status: Partially adopted.)
- The MMU recommends allocating the energy uplift credits paid to units scheduled by PJM as must run in the day-ahead energy market for reasons other than voltage/reactive or black start services as a reliability charge to real-time load, real-time exports and real-time wheels. (Priority: Medium. First reported 2014. Status: Not adopted. Stakeholder process.)
- The MMU recommends that the total cost of providing reactive support be categorized and allocated as reactive services. Reactive services credits should be calculated consistent with the balancing generator credit calculation. (Priority: Medium. First reported 2012. Status: Not adopted. Stakeholder process.)
- The MMU recommends including real-time exports and real-time wheels in the allocation of the cost of providing reactive support to the 500 kV system or above, in addition to real-time load. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends modifications to the calculation of lost opportunity costs credits paid to wind units. The lost opportunity costs credits paid to wind units should be based on the lesser of the desired output, the estimated output based on actual wind conditions and the capacity interconnection rights (CIRs). The MMU recommends that PJM require wind units to request CIRs based on the maximum output used in the ELCC calculation for wind units. (Priority: Low. First reported 2012. Status: Partially adopted.)

- The MMU recommends that PJM clearly identify and classify all reasons for incurring uplift in the day-ahead and the real-time energy markets and the associated uplift charges in order to make all market participants aware of the reasons for these costs and to help ensure a long term solution to the issue of how to allocate the costs of uplift. (Priority: Medium. First reported 2011. Status: Partially adopted.)
- The MMU recommends that PJM revise the current uplift confidentiality rules in order to allow the disclosure of complete information about the level of uplift by unit and the detailed reasons for the level of uplift credits by unit in the PJM region. (Priority: High. First reported 2013. Status: Partially adopted.)[81]

Section 4 Conclusion

Competitive market outcomes result from energy offers equal to short run marginal costs that incorporate flexible operating parameters. When PJM permits a unit to include inflexible operating parameters in its offer and pays uplift based on those inflexible parameters, there is an incentive for the unit to remain inflexible. The rules regarding operating parameters should be implemented in a way that creates incentives for flexible operations rather than inflexible operations. The standard for paying uplift should be the maximum achievable flexibility, based on OEM standards for the benchmark new entrant unit (CONE unit) in the PJM Capacity Market demand (VRR) curve. Applying a weaker standard effectively subsidizes inflexible units by paying them based on inflexible parameters that result from lack of investment and that could be made more flexible. The result inflates uplift costs, suppresses energy prices, and is an incentive to inflexibility.

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

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

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

Accurate short run price signals, equal to the short run marginal cost of generating power, provide market incentives for cost minimizing production to all economically dispatched resources and provide market incentives to load based on the marginal cost of additional consumption. The objective of efficient short run price signals is to minimize system production costs, not to minimize uplift. Repricing the market to reflect commitment costs creates a tradeoff between minimizing production costs and reduction of uplift. The tradeoff exists because when commitment costs are included in prices, the price

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

signal no longer equals the short run marginal cost and therefore no longer provides the correct signal for efficient behavior for market participants making decisions on the margin, whether resources, load, interchange transactions, or virtual traders. This tradeoff now exists based on PJM's recently implemented fast start pricing approach.[82] Fast start pricing affects uplift calculations by introducing a new category of uplift in the balancing market, and changing the calculation of uplift in the day-ahead market.

When units routinely receive substantial revenues through energy uplift payments, these payments are not fully transparent to the market, in part because of the current confidentiality rules. As a result, other market participants, including generation and transmission developers, do not have the opportunity to compete to displace them. As a result, substantial energy uplift payments to a concentrated group of units and organizations have persisted. FERC Order No. 844 authorized the publication of unit specific uplift payments for credits incurred after July 1, 2019.[83] However, Order No. 844 failed to require the publication of unit specific uplift credits for the largest units receiving significant uplift payments, inflexible steam units committed for reliability by PJM in the day-ahead market.

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

82 Fast start pricing was approved by FERC and implemented on September 1, 2021. See 173 FERC ¶ 61,244 (2020).

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

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

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

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

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

Overview: Section 5, Capacity Market

RPM Capacity Market

Market Design

The Reliability Pricing Model (RPM) Capacity Market is a three year forward looking, annual, locational market, with a must offer requirement for Existing Generation Capacity Resources and a must buy requirement for load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand side resources.[84] PJM introduced the Capacity Performance design for the 2017/2018 BRA. PJM introduced a new ELCC method for defining capacity MW offered in the 2025/2026 BRA.[85]

Under RPM, capacity obligations are annual.[86] By design, Base Residual Auctions (BRA) are held for delivery years that are three years in the future despite recent auction delays. First, Second and Third Incremental Auctions (IA) are held for each delivery year.[87] First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year although some incremental auctions have not been held as a result of delays in holding BRAs.[88] A Conditional Incremental Auction may be held if there is a need to procure additional capacity resulting from a delay in a planned large transmission upgrade that was modeled in the BRA for the relevant delivery year.[89] A Reliability Backstop Auction may be conducted if tariff defined criteria are met to resolve reliability criteria violations caused by lack of sufficient capacity procured through RPM auctions.[90] If the installed reserve margin resulting from the total UCAP committed through self supply or BRAs for three consecutive years is more than one percent lower than the approved PJM installed reserve margin, PJM will make a filing with FERC to conduct a Reliability Backstop Auction. If the total UCAP committed for all base load generation resources in BRAs for three consecutive years is less than the forecasted minimum hourly load, PJM will make a filing with FERC to conduct a Reliability Backstop Auction.

The 2025/2026 RPM Third Incremental Auction was conducted in the first three months of 2025.

Market Structure

- **RPM Installed Capacity.** In the first three months of 2025, RPM installed capacity decreased 639.6 MW or 0.4 percent, from 179,656.2 MW on January 1, to 179,016.6 MW on March 31. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- **Reserves.** For the 2025/2026 RPM Base Residual Auction, the sum of cleared MW that were considered categorically exempt from the must offer requirement and the cleared MW of DR is 14,319.1 MW, or 71.1 percent of required reserves and 68.1 percent of total reserves. The fact that almost one third (30.2 percent of required reserves and 29.0 percent of total reserves) of the PJM reserves depend on demand resources that are not subject to the RPM must offer requirement, a core part of the capacity market design, means that reliability is significantly less certain than the stated reserve margins indicate.

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

- **RPM Installed Capacity by Fuel Type.** Of the total installed capacity on March 31, 2025, 49.6 percent was gas; 20.9 percent was coal; 18.0 percent was nuclear; 4.3 percent was hydroelectric; 2.1 percent was oil; 2.0 percent was wind; 0.3 percent was solid waste; and 2.9 percent was solar.
- **Market Concentration.** In the 2025/2026 RPM Third Incremental Auction, all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[91] Offer caps were applied to all sell offers for resources which were subject to mitigation when the capacity market seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[92] [93] [94]
- **Imports and Exports.** Of the 1,268.5 MW of imports offered in the 2025/2026 RPM Base Residual Auction, 1,268.5 MW cleared. Of the cleared imports, 700.5 MW (55.2 percent) were from MISO.
- **Demand Resources.** Committed DR was 7,699.9 MW for June 1, 2024, as a result of cleared capacity for demand resources in RPM auctions for the 2024/2025 Delivery Year (8,064.7 MW) less replacement capacity (364.8 MW).
- **Energy Efficiency Resources.** EE is not a capacity resource but is paid the capacity market clearing price as a subsidy. Committed EE was 7,668.0 MW for June 1, 2024, as a result of MW offered at a price less than or equal to the RPM auction clearing price in RPM auctions for the 2024/2025 Delivery Year (7,716.0 MW) less replacement MW (48.0 MW).

Market Conduct

- **2025/2026 RPM Third Incremental Auction.** Of the 307 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for two generation resources (0.7 percent).

Market Performance

- The 2025/2026 RPM Third Incremental Auction was conducted in the first three months of 2025. The weighted average capacity price for the 2024/2025 Delivery Year is $45.57 per MW-day, including all RPM auctions for the 2024/2025 Delivery Year. The weighted average capacity price for the 2025/2026 Delivery Year is $296.98 per MW-day, including all RPM auctions for the 2025/2026 Delivery Year.
- For the 2024/2025 Delivery Year, RPM annual charges to load are $2.5 billion.
- In the 2025/2026 RPM Base Residual Auction, the market performance was determined to be not competitive.

Part V Reliability Service (RMR)

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

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd in the first three months of 2025 was 6.5 percent, an increase from 4.5 percent in the first three months of 2024.[95]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor in the first three months of 2025 was 85.4 percent, a decrease from 87.9 percent in the first three months of 2024.

91 There are 27 Locational Deliverability Areas (LDAs) identified to recognize locational constraints as defined in "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 10.1. PJM determines, in advance of each BRA, whether the defined LDAs will be modeled in the given delivery year using the rules defined in OATT Attachment DD § 5.10(a)(ii).

92 See OATT Attachment DD § 6.5.

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

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

95 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM generator availability data systems (GADS) database. Data was downloaded from the PJM GADS database on April 23, 2025. EFORd data presented in state of the market reports may be revised based on data submitted after the publication of the reports as generation owners may submit corrections at any time with permission from PJM GADS administrators.

Section 5 Recommendations[96]

Definition of Capacity

- The MMU recommends elimination of the key remaining components of the CP model because they interfere with competitive outcomes in the capacity market and create unnecessary complexity and risk. (Priority: High. First reported 2022. Status: Not adopted.)
- The MMU recommends the enforcement of a consistent definition of capacity resources. The MMU recommends that the tariff requirement to be a physical resource be enforced and enhanced. The requirement to be a physical resource should apply at the time of auctions and should also constitute a commitment to be physical in the relevant delivery year. The requirement to be a physical resource should be applied to all resource types, including planned generation, demand resources, and imports.[97] [98] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that DR providers be required to have a signed contract with specific customers for specific facilities for specific levels of DR at least six months prior to any capacity auction in which the DR is offered. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that Energy Efficiency Resources (EE) not be included in the capacity market construct because PJM's load forecasts have accounted for EE since the 2016 load forecast for the 2019/2020 delivery year. EE is not a capacity resource as defined in the tariff, and there is no reason to continue to pay large subsidies to EE providers.[99] (Priority: Medium. First reported 2016. Status: Adopted 2024.)[100]
- The MMU recommends that intermittent resources, including storage, not be permitted to offer capacity MW based on energy deliveries that exceed their defined deliverability rights (CIRs). Only energy output for such resources at or below the designated CIR/deliverability level should be recognized in the definition of derated capacity (e.g. ELCC). Correctly defined ELCC derating factors are lower than the CIRs required to meet those derating factors. (Priority: High. First reported 2021. Status: Adopted 2023.)
- The MMU recommends that PJM require all market participants to meet their deliverability requirements under the same rules. PJM should end the practice of giving away winter CIRs to intermittent resources that appear to exist because other resources paid for the supporting network upgrades. (Priority: High. First reported 2017. Status: Not adopted.)[101]
- The MMU recommends that the must offer rule in the capacity market apply to all capacity resources. There is no reason to exempt intermittent and capacity storage resources, including hydro, and demand resources from the must offer requirement. The same rules should apply to all capacity resources in order to ensure open access to the transmission system and prevent the exercise of market power through withholding. (Priority: High. First reported 2021. Status: Partially adopted.)
- The MMU recommends that PJM require all market sellers of proposed generation capacity resources, including thermal and intermittent, to submit a binding notice of intent to offer at least six months prior to the base residual auction. This is consistent with the overall MMU recommendation that all capacity resources have a must offer obligation in the capacity market auctions. (Priority: High. First reported 2023. Status: Partially adopted.)
- The MMU recommends that the ELCC be significantly refined to include hourly data that would permit unit specific ELCC ratings, to weight summer and winter risk in a more balanced manner, to eliminate PAI risks, and to pay for actual hourly performance rather than based on relatively inflexible class capacity accreditation ratings derived from a small number of hours of poor performance. (Priority: High. First reported 2023. Status: Not adopted.)

96 The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues. These recommendations have been made in public reports. See Table 5-2.
97 See also Comments of the Independent Market Monitor for PJM, Docket No. ER14-503-000 (December 20, 2013).
98 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).
99 "PJM Manual 19: Load Forecasting and Analysis," § 3.2 Development of the Forecast, Rev. 37 (Dec. 18, 2024).
100 See 189 FERC ¶ 61,095 (2024).
101 This recommendation was first made in the 2020/2021 BRA report in 2017. See the "Analysis of the 2020/2021 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Analysis_of_the_20202021_RPM_BRA_20171117.pdf> (November 11, 2017).

Market Design and Parameters

- The MMU recommends that PJM reevaluate the shape of the VRR curve. The shape of the VRR curve directly results in load paying substantially more for capacity than load would pay with a vertical demand curve. More specifically, the MMU recommended that the VRR curve be rotated half way towards the vertical demand curve at the reliability requirement in the 2022 Quadrennial Review. (Priority: High. First reported 2021. Status: Partially adopted.)
- The MMU recommends that the maximum price on the VRR curve be defined as 1.5 times Net CONE, capped at Gross CONE. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that the reference resource be a CT rather than a CC. The MMU recommends that the ELCC value used to convert the gross CONE in ICAP terms for a CT to the gross CONE in UCAP terms be the ELCC based on winter ratings. (Priority: High. First reported Q3 2024. Status: Adopted.)
- The MMU recommends that the test for determining modeled Locational Deliverability Areas (LDAs) in RPM be redefined. A detailed reliability analysis of all at risk units should be included in the redefined model including transmission constraints inside LDAs. The market design should clear and pay units that are needed for reliability per PJM's transmission reliability analysis in order to forestall RMRs. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM clear the capacity market based on nodal capacity resource locations and the characteristics of the transmission system inside and outside LDAs consistent with the actual electrical facts of the grid. Absent a fully nodal capacity market clearing process, the MMU recommends that PJM use a non-nested model with all LDAs modeled including VRR curves for all LDAs. Each LDA requirement should be met with the capacity resources located within the LDA and exchanges from neighboring LDAs up to the transmission limit. LDAs should be allowed to price separate if that is the result of the LDA supply curves and the transmission constraints between LDAs. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that the net revenue offset calculation used by PJM to calculate the net Cost of New Entry (CONE) and net ACR be based on a forward looking calculation of expected energy and ancillary services net revenues using historical net revenues that are scaled based on forward prices for energy and fuel. (Priority: High. First reported 2014. Status: Not adopted.)[102]
- The MMU recommends that PJM reduce the number of incremental auctions to a single incremental auction held three months prior to the start of the delivery year and reevaluate the triggers for holding conditional incremental auctions. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM not sell back any capacity in any IA procured in a BRA. If PJM continues to sell back capacity, the MMU recommends that PJM offer to sell back capacity in incremental auctions only at the BRA clearing price for the relevant delivery year. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM not buy any capacity in any IA if PJM has already procured excess reserves. (Priority: Medium. First reported 2023. Status: Not adopted.)
- The MMU recommends changing the RPM solution method to explicitly incorporate the cost of uplift (make whole) payments in the objective function. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that the Fixed Resource Requirement (FRR) rules, including obligations and performance requirements, be revised and updated to ensure that the rules reflect current market realities and that FRR entities do not unfairly take advantage of those customers paying for capacity in the PJM capacity market. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that the value of CTRs be defined by the total MW cleared in the capacity market, the internal MW cleared and the imported

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

MW cleared, and not redefined later prior to the delivery year. (Priority: Medium. First reported 2021. Status: Not adopted.)

- The MMU recommends that the market clearing results be used in settlements rather than the reallocation process currently used, or that the process of modifying the obligations to pay for capacity be reviewed. (Priority: Medium. First reported 2021. Status: Not adopted.)[103]
- The MMU recommends that PJM improve the clarity and transparency of its CETL calculations. The MMU also recommends that CETL for capacity imports into PJM be based on the ability to import capacity only where PJM capacity exists and where that capacity has a must offer requirement in the PJM Capacity Market. (Priority: Medium. First reported 2021. Status: Partially adopted 2022.)

Offer Caps, Offer Floors, and Must Offer

- The MMU recommends using the lower of the cost or price-based energy market offer to calculate energy costs in the calculation of the historical net revenues which are an offset to gross ACR in the calculation of unit specific capacity resource offer caps based on net ACR. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that modifications to existing resources, including relatively small proposed increases in the capability of a Generation Capacity Resource be treated as an existing resource and subject to the corresponding market power mitigation rules and no longer be treated as planned and exempt from offer capping. (Priority: Medium. First reported 2012. Status: Not adopted.)[104]
- The MMU recommends that the RPM market power mitigation rule be modified to apply offer caps in all cases when the three pivotal supplier test is failed and the sell offer is greater than the offer cap. This will ensure that market power does not result in an increase in uplift (make whole) payments for seasonal products. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that any combined seasonal resources be required to be in the same LDA and at the same location, in order for the energy market and capacity market to remain synchronized and reliability metrics correctly calculated. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that the definition of avoidable costs in the tariff be corrected to be consistent with the economic definition. Avoidable costs are costs that are neither short run marginal costs, like fuel or consumables, nor fixed costs like depreciation and rate of return. Avoidable costs are the marginal costs of capacity and therefore the competitive offer level for capacity resources and therefore the market seller offer cap. Avoidable costs are the marginal costs of capacity for both new resources and existing resources. (Priority: Medium. First reported 2017. Status: Not adopted.)[105]
- The MMU recommends that major maintenance costs be included in the definition of avoidable costs and removed from energy offers because such costs are avoidable costs and not short run marginal costs. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that capacity market sellers be required to explicitly request and support the use of minimum MW quantities (inflexible sell offer segments) and that the requests only be permitted for defined physical reasons. (Priority: Medium. First reported 2018. Status: Not adopted.)

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

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

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

- The MMU recommends that, as part of the MOPR unit specific standard of review, all projects be required to use the same basic modeling assumptions. That is the only way to ensure that projects compete on the basis of actual costs rather than on the basis of modeling assumptions.[106] (Priority: High. First reported 2013. Status: Not adopted.)

Performance Incentive Requirements of RPM

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

Capacity Imports and Exports

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

Deactivations/Retirements

- The MMU recommends that the notification requirement for deactivations be extended from the current one quarter prior (See Table 5-29) to 12 months prior to an auction in which the unit will not be offered due to deactivation; and no less than 12 months prior to the date of deactivation (Priority: Low. First reported 2012. Status: Partially adopted.)
- The MMU recommends elimination of both the cost of service recovery rate option and the deactivation avoidable cost rate option for providing Part V reliability service (RMR), and their replacement with clear language that provides for the recovery of 100 percent of the actual incremental costs required to operate to provide the service plus a defined incentive. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that units recover all and only the incremental costs, including incremental investment costs without a cap, required to provide Part V reliability service (RMR service) that the unit owner would not have incurred if the unit owner had deactivated its unit as it proposed, plus a defined incentive payment. Customers should bear

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

no responsibility for paying previously incurred (sunk) costs, including a return on or of prior investments. (Priority: High. First reported 2010. Status: Not adopted.)

- The MMU recommends that the same reliability standard be used in capacity auctions as is used by PJM transmission planning. One result of the current design is that a unit may fail to clear in a BRA, decide to retire as a result, but then be found to be needed for reliability by PJM planning and paid under Part V of the OATT (RMR) to remain in service while transmission upgrades are made. (Priority: High. First reported 2023. Status: Not adopted.)
- The MMU recommends that if units that are paid under Part V of the OATT (RMR) are included in the calculation of CETO and/or reliability in the relevant LDA, the capacity of the RMR resources should also be included in capacity market supply at zero cost, but without all the obligations of a capacity resource, in order to ensure that the capacity market price signal reflects the appropriate supply and demand conditions. (Priority: High. First reported 2023. Status: Partially adopted.)
- The MMU recommends that units that are paid under Part V of the OATT (RMR) not be included in the calculation of CETO or reliability in the relevant LDA, in order to ensure that the capacity market price signal reflects the appropriate supply and demand conditions. (Priority: High. First reported 2023. Status: Not adopted.)
- The MMU recommends that all CIRs be returned to the pool of available interconnection capability on the retirement date of generation resources in order to facilitate timely and competitive entry into the PJM markets, open access to the transmission system and maintain the priority order defined by the queue process. (Priority: High. First reported 2023. Status: Not adopted.)

Section 5 Conclusion

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

The MMU concludes that the results of the 2025/2026 RPM Base Residual Auction were significantly affected by flawed market design decisions including by the CP design, by PJM's ELCC approach, by the definition of the maximum VRR price as gross CONE, by the failure to extend the RPM must offer requirement to all resources, including, in some cases, the exercise of market power through the withholding of categorically exempt resources, by the product definition and lack of market power mitigation for demand resources, and by the exclusion from supply of the defined RMR resources. The BRA prices do not reflect supply and demand fundamentals but reflect, in significant part, PJM decisions about the definition of supply and demand. The auction results were not solely the result of the introduction of the ELCC market design and do also reflect, in part, the tightening of supply and demand conditions in the PJM Capacity Market.[107] PJM subsequently filed changes that were approved by FERC to adopt two of the MMU's recommendations, the inclusion of specific RMR resources as supply in the next two BRAs and the elimination of the categorical exemption to the RPM must offer requirement for all but demand resources.[108] [109]

The capacity market is, by design, always tight in the sense that total supply is generally only slightly larger than demand. While the market may be long at times, that is not the equilibrium state. Market power is and will remain endemic to the structure of the PJM Capacity Market. Nonetheless, a competitive outcome can be assured by appropriate market power mitigation

107 PJM's ELCC filing that created many of these issues was approved by FERC. 186 FERC ¶ 61,080 (January 30, 2024).
108 See Letter Order, FERC Docket No. ER25-682-001 (April 29, 2025).
109 190 FERC ¶ 61,117 (2025).

rules within an effective market design. Detailed market power mitigation rules are included in the PJM Open Access Transmission Tariff (OATT or Tariff). Reliance on the RPM design for competitive outcomes means reliance on the market power mitigation rules.

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

For the 2025/2026 RPM Base Residual Auction, the level of committed demand resources (6,085.6 MW UCAP) exceeds the entire level of excess capacity (870.9 MW). This is not consistent with the defined obligations of DR compared to other capacity resources. DR capacity resources do not have a must offer obligation in the energy market. DR capacity resources do not have a must offer obligation in the capacity market. The definition of performance for DR is not to provide a defined incremental level of MW when called but is only to be at a defined level of demand. DR capacity resources do not have a defined market seller offer cap. PJM markets for the first time in 2025/2026 will rely on demand response resources as part of the required reserve margin, rather than as excess above the required reserve margin. PJM markets for the first time in 2025/2026 will experience the implications of the definition of demand resources as a purely emergency capacity resource, when demand resources are a significant share of required reserves. Nonetheless, as another significant flaw in the market design, PJM does not include DR in its definition of primary or secondary reserves in the energy market. DR, for all these reasons, is an inferior resource in the capacity market. PJM does not have clear rules defining when the operators must call on DR.

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

All participants to which the three pivotal supplier (TPS) test was applied (in the RTO, BGE, and Dominion RPM markets) failed the three pivotal supplier test. The result was that offer caps were applied to all sell offers for Existing Generation Capacity Resources when the capacity market seller did not pass the test, the submitted sell offer exceeded the tariff defined offer cap, and the submitted sell offer, absent mitigation, would have resulted in a higher market clearing price.[110] [111]

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

The MMU recommends elimination of the key remaining components of the CP model because they interfere with competitive outcomes in the capacity market and create unnecessary complexity and risk. The use of Net CONE as the basis for the PAI penalty rate is unsupported by economic logic. The use of Net CONE to establish penalties is a form of arbitrary administrative pricing that creates arbitrarily high risk for generators, creates an artificial rationale for not having a must offer obligation for intermittent and storage resources, creates complexity in the calculation of CPQR and increases CPQR above rational levels, and ultimately raises the price of capacity above the competitive level. Given PJM's recent decision to rely on conservative

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

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

operations during tight market conditions as evidenced during Polar Vortex 2025 in January 2025, the probability of a PAI is extremely small. In addition, PJM tightened the definition of a PAI and capped the total annual penalty at 1.5 times the resource's capacity market BRA clearing price. As a result, there is no effective performance incentive remaining in the capacity market.

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

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

The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[112] [113] [114] [115] [116] [117] [118] [119] [120] [121] [122] In the first three months of 2025, the MMU prepared a number of RPM related reports and testimony, shown in Table 5-2.

The PJM markets have worked to provide incentives to entry and to retain capacity. A majority of capacity investments in PJM were financed by market sources. Of the 55,064.5 MW of additional capacity that cleared in RPM auctions for the 2007/2008 through 2023/2024 Delivery Years, 42,444.9 MW (77.1 percent) were based on market funding. Of the 4,955.0 MW of additional capacity that cleared in RPM auctions for the 2024/2025 and 2025/2026 Delivery Year, 3,239.4 MW (65.4 percent) were based on market funding. Those investments were made based on the assumption that markets would be allowed to work and that inefficient units would exit.

It is essential that any approach to the PJM markets incorporate a consistent view of how the preferred market design is expected to provide competitive results in a sustainable market design over the long run. A sustainable market design means a market design that results in appropriate incentives

112 See "Analysis of the 2018/2019 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20182019_RPM_Base_Residual_Auction_20160706.pdf> (July 6, 2016).
113 See "Analysis of the 2019/2020 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20192020_RPM_BRA_20160831-Revised.pdf> (August 31, 2016).
114 See "Analysis of the 2020/2021 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Analysis_of_the_20202021_RPM_BRA_20171117.pdf> (November 11, 2017).
115 See "Analysis of the 2021/2022 RPM Base Residual Auction - Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).
116 See "Analysis of the 2022/2023 RPM Base Residual Auction," <https://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20222023_RPM_BRA_20220222.pdf> (February 22, 2022).
117 See "Analysis of the 2023/2024 RPM Base Residual Auction," <https://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf> (October 28, 2022).
118 See the "Analysis of the 2024/2025 RPM Base Residual Auction," <https://www.monitoringanalytics.com/reports/Reports/2023/IMM_Analysis_of_the_20242025_RPM_Base_Residual_Auction_20231030.pdf> (October 30, 2023).
119 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2017," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Report_on_Capacity_Replacement_Activity_4_20171214.pdf> (December 14, 2017).
120 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).
121 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part A," <https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_A_20240920.pdf> (September 20, 2024).
122 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part B," <https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_B_20241015.pdf> (October 15, 2024).

to competitive market participants to retire units and to invest in new units over time such that reliability is ensured as a result of the functioning of the market.

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

Overview: Section 6, Demand Response

- **Demand Response Activity.** Demand response activity includes economic demand response (economic resources), emergency and pre-emergency demand response (demand resources), synchronized reserves and regulation. Economic demand response participates in the energy market. Emergency and pre-emergency demand response participates in the capacity market and energy market.[123] Demand response resources participate in the synchronized reserve market. Demand response resources participate in the regulation market.

  Total demand response revenue increased by $5.9 million, 15.9 percent, from $37.1 million in the first three months of 2024 to $43.1 million in the first three months of 2025, primarily due to increases in economic and regulation market revenue. Emergency demand response revenue accounted for 67.3 percent of all demand response revenue, economic demand response for 12.8 percent, demand response in the synchronized reserve market for 7.7 percent and demand response in the regulation market for 12.2 percent.

  Total emergency demand response revenue increased by $0.4 million, 1.4 percent, from $28.6 million in the first three months of 2024 to $29.0 million in the first three months of 2025.[124] This increase consisted entirely of capacity market revenue.

  Economic demand response revenue increased by $2.7 million, 99.1 percent, from $2.8 million in the first three months of 2024 to $5.5 million in the first three months of 2025.[125] Demand response revenue in the synchronized reserve market increased by $0.7 million, 26.3 percent, from $2.6 million in the first three months of 2024 to $3.3 million in the first three months of 2025. Demand response revenue in the regulation market increased by $2.1 million, 65.4 percent, from $3.2 million in the first three months of 2024 to $5.2 million in the first three months of 2025.

- **Demand Response Energy Payments are Uplift.** Energy payments to emergency and economic demand response resources are uplift. LMP does not cover energy payments although emergency and economic demand response can and does set LMP. Energy payments to emergency demand resources are paid by PJM market participants in proportion to their net purchases in the real-time market. Energy payments to economic demand resources are paid by real-time exports from PJM and real-time loads in each zone for which the load-weighted, average real-time LMP for the hour during which the reduction occurred is greater than or equal to the net benefits test price for that month.[126]

- **Demand Response Market Concentration.** The ownership of economic load response resources was highly concentrated in the first three months of 2024 and 2025. The HHI for economic resource reductions decreased by 531 points from 9235 in the first three months of 2024 to 8703 in the first three months of 2025. The ownership of emergency load response resources is highly concentrated. The HHI for emergency load response committed MW was 2295 for the 2023/2024 Delivery Year. In the 2023/2024 Delivery Year, the four largest CSPs owned 85.6 percent of all committed demand response UCAP MW. The HHI for emergency demand response committed MW is 2387 for the 2024/2025 Delivery Year. In the 2024/2025 Delivery Year, the four largest CSPs own 88.5 percent of all committed demand response UCAP MW.

123 Emergency demand response refers to both emergency and pre-emergency demand response. With the implementation of the Capacity Performance design, and prior to the July 30, 2023 FERC approved revisions to PJM's Tariff to eliminate the dispatch of demand response as a trigger for calling an emergency and for defining a Performance Assessment Interval (PAI), there is no functional difference between the emergency and pre-emergency demand response resource.

124 The total credits and MWh numbers for demand resources were downloaded as of April 11, 2025, and may change as a result of continued PJM billing updates. As a result, March 2025 figures were not yet available.

125 Economic credits are synonymous with revenue received for reductions under the economic load response program.

126 "PJM Manual 28: Operating Agreement Accounting," § 11.2.2, Rev. 98 (Dec. 17, 2024).

- **Limited Locational Dispatch of Demand Resources.** With full implementation of the Capacity Performance rules in the capacity market in the 2020/2021 Delivery Year, PJM should be able to individually dispatch any capacity performance resource, including demand resources. PJM cannot dispatch demand resources by node with the current rules because demand resources are not registered to a node. Aggregation rules allow a demand resource that incorporates many small End Use Customers to span an entire zone, which is inconsistent with nodal dispatch.
- **Energy Efficiency.** Energy efficiency resources are not capacity resources in PJM. The total MW of energy efficiency resources paid decreased by 80.6 percent, from 7,716.0 MW in the 2024/2025 Delivery Year to 1,493.2 MW in the 2025/2025 Delivery Year. In the 2025/2026 Delivery Year, although EE is not a capacity resource and did not clear in the capacity market, the EE MW paid for the Delivery Year were equal to 1.1 percent of all actual cleared capacity MW.
- **Energy Efficiency Payments are a Subsidy and Uplift.** Payments from the buyers of capacity to energy efficiency providers are a subsidy and uplift. Energy efficiency is not a capacity resource and does not contribute to reliability.
- **Energy Efficiency Market Concentration.** The HHI for Energy Efficiency on an aggregate market basis shows that ownership is highly concentrated. The four largest companies typically own 90 percent or more of all paid Energy Efficiency MW. The HHI for Energy Efficiency resources also shows that ownership is highly concentrated for the 2024/2025 Delivery Year, with an HHI value of 5749. In the 2024/2025 Delivery Year, the four largest companies own 98.0 percent of all paid Energy Efficiency MW.

Section 6 Recommendations

- The MMU recommends that PJM report the response of demand capacity resources to dispatch by PJM as the actual change in load rather than simply the difference between the amount of capacity purchased by the customer and the actual metered load. The current approach significantly overstates the response to PJM dispatch. (Priority: High. First reported 2023. Status: Not adopted.)
- The MMU recommends that demand resources offering as supply in the capacity market be required to offer a guaranteed load drop (GLD) below their PLC to ensure that demand resources provide an identifiable MW resource to PJM when called. (Priority: High. First reported 2023. Status: Not adopted.)
- The MMU recommends, as an alternative to including demand resources as supply in the capacity market, that demand resources have the option to be on the demand side of the markets, that customers be able to avoid capacity and energy charges by not using capacity and energy at their discretion, that customer payments be determined only by metered load, and that PJM forecasts immediately incorporate the impacts of demand side behavior. (Priority: High. First reported 2014. Status: Not adopted.)
- The MMU recommends that the option to specify a minimum dispatch price (strike price) for demand resources be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate.[127] (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that the maximum offer for demand resources be the same as the maximum offer for generation resources and that the same cost verification rules applied to generation resources apply to demand resources. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that the demand resources be treated as economic resources, responding to economic price signals like other capacity resources. The MMU recommends that demand resources not be treated as emergency resources, not trigger a PJM emergency and not trigger a Performance Assessment Interval. The MMU recommends that demand resources be available for every hour of the year. (Priority: High. First reported 2012. Status: Partially adopted.)

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

- The MMU recommends that the Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market incentive is already provided in the economic program. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends that, if demand resources remain in the capacity market, a daily energy market must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources.[128] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that demand resources be required to provide their nodal location, comparable to generation resources. (Priority: High. First reported 2011. Status: Not adopted.)
- The MMU recommends that PJM require nodal dispatch of demand resources with no advance notice required or, if nodal location is not required, subzonal dispatch of demand resources with no advance notice required. The MMU recommends that, if PJM continues to use subzones for any purpose, PJM clearly define the role of subzones in the dispatch of demand response. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not remove any defined subzones and maintain a public record of all created and removed subzones. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM eliminate the measurement of compliance across zones within a compliance aggregation area (CAA). The multiple zone approach is less locational than the zonal and subzonal approach and creates larger mismatches between the locational need for the resources and the actual response. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that measurement and verification methods for demand resources be modified to reflect compliance more accurately. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and that negative values be included when calculating event compliance across hours and registrations. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM adopt the ISO-NE five-minute metering requirements in order to ensure that operators have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions.[129] (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends demand response event compliance be calculated on a five minute basis for all capacity performance resources and that the penalty structure reflect five minute compliance. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends that load management testing be initiated by PJM with advance notice to CSPs identical to the actual lead time required in an emergency in order to accurately represent the conditions of an emergency event. (Priority: Low. First reported 2012. Status: Partially adopted.)
- The MMU recommends that shutdown cost be defined as the cost to curtail load for a given period that does not vary with the measured reduction or, for behind the meter generators, be the start cost defined in Manual 15 for generators. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the Net Benefits Test be eliminated and that demand response resources be paid LMP less any generation component of the applicable retail rate. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the tariff rules for demand response clarify that a resource and its CSP, if any, must notify PJM of material changes affecting the capability of the resource to perform as registered and must terminate or modify registrations that are no longer capable of responding to PJM dispatch directives at defined levels because load has been reduced or eliminated, as in the case of bankrupt and/or out of service facilities. (Priority: Medium. First reported 2015. Status: Not adopted.)

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

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

- The MMU recommends that there be only one demand response product in the capacity market, with an obligation to respond when called for any hour of the delivery year. (Priority: High. First reported 2011. Status: Partially adopted.[130])
- The MMU recommends that the lead times for demand resources be shortened to 30 minutes with a one hour minimum dispatch for all resources. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends setting the baseline for measuring capacity compliance under winter compliance at the customers' PLC, similar to GLD, to avoid double counting. (Priority: High. First reported 2010. Status: Partially adopted.)
- The MMU recommends the Relative Root Mean Squared Test be required for all demand resources with a CBL. (Priority: Low. First reported 2017. Status: Partially adopted.)
- The MMU recommends that 30 minute pre-emergency and emergency demand response be considered to be 30 minute reserves. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that energy efficiency resources (EE) not be included in the capacity market mechanism and that PJM should ensure that the impact of EE measures on the load forecast is incorporated immediately. (Priority: Medium. First reported 2018. Status: Adopted 2024.)[131] [132]
- The MMU recommends that demand reductions based entirely on behind the meter generation be capped at the lower of economic maximum or actual generation output. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that all demand resources register as Pre-Emergency Load Response and that the Emergency Load Response Program be eliminated. (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends that EDCs not be allowed to participate in markets as DER aggregators in addition to their EDC role. (Priority: High. First reported 2021. Status: Not adopted.)
- The MMU recommends that PJM include a 5.0 MW maximum size cap on DER aggregations. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that PJM use a nodal approach for DER participation in PJM markets that excludes multinodal aggregation. (Priority: Medium. First reported 2022. Status: Partially adopted.)
- The MMU recommends that the Commission require PJM to include in OATT Attachment M the explicit statement that the Market Monitor's role includes the right to collect information from EDCs and DERA related to actions taken on the distribution system related to DERs. (Priority: Medium. First reported 2023. Status: Not adopted.)
- The MMU recommends that PJM revise the requirements for reporting expected real time energy load reductions by CSPs to PJM to improve the accuracy and usefulness to PJM's system operators. (Priority: Medium. First reported 2023. Status: Not adopted.)
- The MMU recommends that PJM define when operators can and should call on demand resources, given that a call on demand resources no longer triggers a PAI. The MMU recommends that PJM revise the performance requirements for demand resources to include an event specific measurement for dispatch occurring outside of Performance Assessment Events and penalties for nonperformance. (Priority: Medium. First reported 2023. Status: Not adopted.)

Section 6 Conclusion

A fully functional demand side of the electricity market means that End Use Customers or their designated intermediaries will have the ability to see real-time energy price signals in real time, will have the ability to react to real-time prices in real time and will have the ability to receive the direct benefits

130 PJM's Capacity Performance design requires resources to respond when called for any hour of the delivery year, but demand resources still have a limited mandatory compliance window.
131 189 FERC ¶ 61,095 (2024).
132 Originally incorporated with auctions conducted in 2016 for the 2016/2017 Delivery Year and forward. The mechanics of the EE addback mechanism were modified beginning with the 2023/2024 Delivery Year.

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

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

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

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

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

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

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

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

In order to be a substitute for generation, compliance by demand resources with PJM dispatch instructions should include both increases and decreases in load. Compliance of demand resources for capacity purposes during a Performance Assessment Event is measured relative to either Peak Load Contribution or Winter Peak Load, which are static values. If a demand resource's metered load increases above these reference values during a PAI, the current method applied by PJM simply ignores increases in load and thus artificially overstates compliance.[133]

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

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

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

The MMU peak shaving proposal at the Summer-Only Demand Response Senior Task Force (SODRSTF) is an example of how to create a demand side product that is on the demand side of the market and not on the supply side.[134] The MMU proposal was based on the BGE load forecasting program and the Pennsylvania Act 129 Utility Program.[135] [136] Under the MMU proposal, participating load would inform PJM prior to an RPM auction of the MW participating, the months and hours of participation and the temperature humidity index (THI) threshold at which load would be reduced. PJM would reduce the load forecast used in the RPM auction based on the designated reductions. Load would agree to curtail demand to at or below a defined FSL, less than the customer PLC, when the THI exceeds a defined level or load exceeds a specified threshold. By relying on metered load and the PLC, load can reduce its demand for capacity and that reduction can be verified without complicated and inaccurate metrics to estimate load reductions. Under PJM's weakened version of the program, performance is measured under the current economic demand response CBL rules which means relying on load estimates rather than actual metered load.[137] PJM's proposal includes only a THI curtailment trigger and not an overall load curtailment trigger.

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

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

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

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

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

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

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

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

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

2018).

This approach would work under the CP design in the capacity market. This approach is entirely consistent with the Supreme Court decision in *EPSA* as it does not depend on whether FERC has jurisdiction over the demand side.[138] This approach will allow FERC to more fully realize its overriding policy objective to create competitive and efficient wholesale energy markets. The decision of the Supreme Court addressed jurisdictional issues and did not address the merits of FERC's approach. The Supreme Court's decision has removed the uncertainty surrounding the jurisdictional issues and created the opportunity for FERC to revisit its approach to demand side.

Any discussion of demand resource performance during a PAI must recognize the significant problems with the definition of performance for demand resources. As defined by PJM rules, performance, contrary to intuition, does not mean actually reducing load in response to a PJM request for demand resources. Performance means only that, on a net portfolio basis, the amount of capacity paid for in the capacity market (PLC) minus actual metered load is equal to the amount of demand side capacity sold in the capacity market (ICAP). If a demand resource location was already at a reduced load level when PJM called a PAI, the demand resource would be deemed to have performed if the PLC less the metered load level was equal to the ICAP sold in the capacity market. The standard reporting of demand side response is therefore misleading because it includes loads that were already lower for any reason as a response. That is exactly what happened during Elliott.

Overview: Section 7, Net Revenue

Net Revenue

- Energy market net revenues are significantly affected by energy prices and fuel prices. Energy prices, gas prices and coal prices increased in the first three months of 2025 compared to the first three months of 2024. The net effects were that in the first three months of 2025, average energy market theoretical net revenues increased by 45 percent for a new combustion turbine (CT), increased by 51 percent for a new combined cycle (CC), increased by 202 percent for a new coal plant (CP), increased by 67 percent for a new nuclear plant, increased by 243 percent for a new

138 577 U.S. 260 (2016).

diesel (DS), increased by 82 percent for a new onshore wind installation, increased by 80 percent for a new offshore wind installation and increased by 121 percent for a new solar installation.

- The price of natural gas and coal increased in the first three months of 2025. The marginal costs of a new CT were greater than the marginal cost of a new CP in January, February and March 2025. The marginal costs of a new CC were greater than the marginal cost of a new CP in January and February, 2025.
- In the first three months of 2025, spark spreads and dark spreads and the volatility of spark spreads and dark spreads increased in BGE, COMED and Western Hub compared to the first three months of 2024. In the first three months of 2025, spark spreads decreased while dark spreads and the volatility of both spark spreads and dark spreads increased in PSEG compared to the first three months of 2024.
- Of the 16 PJM nuclear plants analyzed, all are expected to cover their avoidable costs from energy and capacity market revenues in 2025 and 2026, without any subsidies.

Section 7 Recommendations

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

Section 7 Conclusion

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

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

Overview: Section 8, Environmental and Renewables

Federal Environmental Regulation

- **MATS.** The U.S. Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards rule (MATS) applies the Clean Air Act (CAA) maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide.[139] On April 24, 2024, the EPA finalized a strengthened and

139 See *National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil Fuel Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234, 77 Fed. Reg. 9304 (Feb. 16, 2012).

updated MATS rule reflecting recent developments in control technologies and the performance of coal fired plants.[140]

- **Air Quality Standards (NO_x and SO_2 Emissions).** The CAA requires each state to attain and maintain compliance with fine particulate matter (PM) and ozone national ambient air quality standards (NAAQS). The CAA also requires that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS.[141] (Transport Rule) On March 15, 2021, the EPA finalized decreases to allowable emissions under the Cross-State Air Pollution Rule (CSAPR) and the 2008 ozone NAAQS for 10 PJM states.[142] On February 28, 2022, the EPA issued a federal implementation plan for implementation of CSAPR (also known as the Good Neighbor Plan),[143] which applies when no state implementation plan has been approved. On June 27, 2024, the Supreme Court of the United States granted a stay of the federal implementation plan pending judicial review.[144] The effect of the stay is to eliminate the ozone season NO_x emissions budgets for electric generating units in the PJM states. Unless and until the stay is lifted, no federal implementation plan is effective in PJM states and the state emissions budgets are not effective. The EPA had previously rejected all proposed state implementation plans for PJM states. Under the new administration the future of the federal implementation plan is uncertain, and attempts to create state implementation plans are expected to resume.
- **NSR.** The CAA's NSR program is a preconstruction permitting program that requires certain stationary sources of air pollution to obtain permits prior to beginning construction. Parts C and D of Title I of the CAA provide for New Source Review (NSR) in order to prevent new projects and projects receiving major modifications from increasing emissions in areas currently meeting NAAQS or from inhibiting progress in areas that do not.[145] NSR requires permits before construction commences. NSR review applies a two part analysis to projects at facilities such as power plants, some of which involve multiple units and combinations of new and existing units.[146].
- **RICE.** Stationary reciprocating internal combustion engines (RICE) are electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power. RICE must be tested annually.[147] RICE do not have to meet the same emissions standards if they are stationary emergency RICE. Environmental regulations allow stationary emergency RICE participating in demand response programs to operate for up to 100 hours per calendar year when providing emergency demand response when there is a PJM declared NERC Energy Emergency Alert Level 2 or there are five percent voltage/frequency deviations.

  PJM does not prevent stationary emergency RICE that cannot meet its capacity market obligations as a result of EPA emissions standards from participating in PJM markets as DR. Some stationary emergency RICE that cannot meet its capacity market obligations as a result of emissions standards are now included in DR portfolios. Stationary emergency RICE should be prohibited from participation as DR either when registered individually or as part of a portfolio if it cannot meet its capacity market obligations as a result of emissions standards.
- **Greenhouse Gas Emissions.** On April 25, 2024, the EPA issued a rule (called "Carbon Emissions Rule" in this report) taking four separate actions under CAA § 111(a)(1) addressing greenhouse gas (GHG) emissions from fossil fuel-fired electric generating units (EGUs):[148] the rule repeals the Affordable Clean Energy (ACE) Rule; the rule finalizes emission guidelines for GHG emissions from existing coal fired and oil/gas fired steam generating EGUs; the rule revises the New Source Performance Standards (NSPS) for GHG emissions from new and reconstructed fossil fuel-fired stationary combustion turbine EGUs; the rule revises the NSPS for GHG emissions from fossil fuel-fired steam generating units that undertake a large modification, based upon the 8-year review required by the CAA.

140 See *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, Final Rule, Docket No. EPA-HQ-OAR-2018-0794, 89 Fed. Reg. 38508 (May 7, 2024).
141 CAA § 110(a)(2)(D)(i)(I).
142 *Revised Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS*, Docket No. EPA-HQ-OAR-2020-0272; FRL-10013-42- OAR, 85 Fed. Reg. 23054 (Apr. 30, 2021).
143 See *Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard*, Docket No. EPA-HQ-OAR-2021-0668; FRL 8670-01-OAR, 87 Fed. Reg. 20036 (April 6, 2022).
144 Ohio v. EPA, Slip Op. No. 23A349. (S. Ct. June 27, 2024); Utah v. EPA, D.C. Cir. Case No. Case No. 23-1157, et al.
145 42 U.S.C § 7470 et seq.
146 40 CFR § 52.21.
147 See 40 CFR § 63.6640(f).
148 See *New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule*, Proposed Rule, Docket No. EPA-HQ-OAR-2023-0072, 89 Fed. Reg. 39798 (May 9, 2024) ("Carbon Emissions Rule").

The rule deferred action on emission guidelines for GHG emissions from existing fossil fuel-fired stationary combustion turbines.

The Carbon Emissions Rule reflects the application of the best system of emission reduction (BSER). The proposal includes emission guidelines for GHG emissions from existing fossil fuel-fired steam generating EGUs (including coal, oil or gas). For coal fired EGUs, compliance is required by January 1, 2030, with standards that vary based on whether the EGU commits to retire before 2032, 2035, 2040, or does not commit to retire before 2040.[149] The EPA proposes to repeal the Affordable Clean Energy Rule.[150]

- **Cooling Water Intakes.** An EPA rule implementing Section 316(b) of the Clean Water Act (CWA) requires that cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts.[151]
- **Waters of the United States.** On August 29, 2023, the EPA issued a final rule defining adjacent wetlands consistent with the Supreme Court holding that an adjacent wetland is "... a relatively permanent body of water connected to traditional interstate navigable waters ... and ... that the wetland has a continuous surface connection with that water."[152] The rule became effective on September 8, 2023.[153]
- **Effluents.** Under the CWA, the EPA regulates (National Pollutant Discharge Elimination System (NPDES)) discharges from and intakes to power plants, including water cooling systems at steam electric power generating stations. Since 2015, the EPA has been strengthening certain discharge limits applicable to steam generating units, and some plant owners have already indicated an intent to close certain generating units as a result. In May 2024, the EPA finalized a rule strengthening regulation of effluent discharges.[154]

149 Carbon Emissions Rule at 33371-33373.
150 Carbon Emissions Rule at 33243.
151 See EPA, *National Pollutant Discharge Elimination System—Final Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities*, EPA-HQ-OW-2008-0667, 79 Fed. Reg. 48300 (August 15, 2014).
152 See Revised Definition of "Waters of the United States," EPA-HQ-OW-2023-0346, 88 Fed. Reg. 61964 (September 8, 2023).
153 See *id.*
154 See *Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, Final Rule, EPA Docket No. EPA-HQ-OW-2009-0819; FRL-8794-01- OW, 89 Fed. Reg. 40199 (May 9, 2024).

- **Coal Ash.** The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.[155] The EPA has adopted significant changes to the implementing regulations that will require closing noncompliant impoundments, and, as a result, the host power plant. The EPA is implementing a process for extensions to as late as October 17, 2028. The EPA is reviewing applications received from PJM plant owners for extensions of the deadline for compliance with the revised Coal Combustion Residuals Rule.

State Environmental Regulation

- **Regional Greenhouse Gas Initiative (RGGI).** The Regional Greenhouse Gas Initiative (RGGI) is a CO_2 emissions cap and trade agreement among Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont that applies to power generation facilities. The most recent RGGI auction, held on March 12, 2025, cleared at $19.76 per short ton, or $21.78 per metric tonne.
- **Illinois Climate and Equitable Jobs Act (CEJA).** On September 16, 2021, the Climate and Equitable Jobs Act (CEJA) became effective. CEJA created an expanded nuclear subsidy program. CEJA mandated that all fossil fuel plants close by 2045. CEJA established emissions caps for investor owned, gas-fired units with three years of operating history, effective October 1, 2021, on a rolling 12 month basis. More than 10,000 MW of capacity are currently affected. The CEJA operating hour limits have resulted in significant opportunity cost adders to cost-based energy market offers for affected units.
- **Carbon Price.** If the price of carbon were $50.00 per metric tonne, short run marginal costs would have increased by $24.45 per MWh or 45.0 percent for a new combustion turbine (CT) unit, $16.85 per MWh or 41.6 percent for a new combined cycle (CC) unit and $43.12 per MWh or 122.0 percent for a new coal plant (CP) for the first three months of 2025.

155 42 U.S.C. §§ 6901 *et seq.*

State Renewable Portfolio Standards

- **RPS.** In PJM, ten of 14 jurisdictions have enacted legislation requiring that a defined percentage of retail suppliers' load be served by renewable resources, for which definitions vary. These are typically known as renewable portfolio standards, or RPS. As of March 31, 2025, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Virginia and Washington, DC have renewable portfolio standards. Indiana has a voluntary renewable portfolio standard. Kentucky, Tennessee and West Virginia do not have renewable portfolio standards.
- **RPS Cost.** The cost of complying with RPS, as reported by the states, is $11.8 billion over the nine year period from 2014 through 2022, an average annual RPS compliance cost of $1.3 billion. The compliance cost for 2022, the most recent year with almost complete data, was $2.4 billion.[156]

Emissions Controls in PJM Markets

- **Regulations.** Environmental regulations affect decisions about emission control investments in existing units, investment in new units and decisions to retire units. As a result of environmental regulations and agreements to limit emissions, many PJM units burning fossil fuels have installed emission control technology.
- **Emissions Controls.** In PJM, as of March 31, 2025, 97.4 percent of coal steam MW had some type of flue-gas desulfurization (FGD) technology to reduce SO_2 emissions, 99.8 percent of coal steam MW had some type of particulate matter (PM) control, and 99.8 percent of coal steam MW had NO_X emission control technology. All coal steam units in PJM are compliant with the state and federal emissions limits established by MATS.

156 The 2022 compliance cost value for PJM states does not include Delaware, Michigan or North Carolina. Based on past data these states generally account for approximately 2.0 percent of the total RPS compliance cost of PJM states.

Renewable Generation

- **Renewable Generation.** Wind and solar generation was 7.2 percent of total generation in PJM for the first three months of 2025. RPS Tier I generation was 8.4 percent of total generation in PJM and RPS Tier II generation was 1.7 percent of total generation in PJM for the first three months of 2025. Only Tier I generation is defined to be renewable but Tier 1 includes some carbon emitting generation.
- PJM states with RPS rely heavily on imports and generation from behind the meter resources for RPS compliance. In the first three months of 2025, Tier I generation from PJM generators met only 53.0 percent of the Tier I RPS requirements.

Section 8 Recommendations

- The MMU recommends that renewable energy credit markets based on state renewable portfolio standards be brought into PJM markets as they are an increasingly important component of the wholesale energy market. The MMU recommends that there be a single PJM operated forward market for RECs, for a single product based on a common set of state definitions of renewable technologies, with a single clearing price, trued up to real-time delivery. (Priority: High. First reported 2010. Status: Not adopted.)
- The MMU recommends that jurisdictions with a renewable portfolio standard make the price and quantity data on supply and demand more transparent. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that the Commission reconsider its disclaimer of jurisdiction over RECs markets because, given market changes since that decision, it is clear that RECs materially affect jurisdictional rates. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM provide a full analysis of the impact of carbon pricing on PJM generating units and carbon pricing revenues to the PJM states in order to permit the states to consider a potential agreement on the development of a multistate framework for carbon pricing and the distribution of carbon revenues. (Priority: High. First reported 2018. Status: Not adopted.)

- The MMU recommends that load and generation located at separate nodes be treated as separate resources in order to ensure that load and generation face consistent incentives throughout the markets. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that stationary emergency RICE be prohibited from participation as DR either when registered individually or as part of a portfolio if it cannot meet the capacity market requirements to be DR as a result of emissions standards that impose environmental run hour limitations. (Priority: Medium. First reported 2019. Status: Not adopted.)

Section 8 Conclusion

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

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

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

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

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

Existing REC markets are not consistently or adequately transparent. Data on REC prices, clearing quantities and markets are not publicly available for all PJM states. The economic logic of RPS programs and the associated REC and SREC prices is not always clear. The price of carbon implied by REC prices ranges from $11.32 per tonne in Ohio to $65.85 per tonne in Virginia. The price of carbon implied by SREC prices ranges from $70.23 per tonne in Pennsylvania to $824.78 per tonne in Washington, DC. The effective prices for carbon compare to the RGGI clearing price in March 2025 of $21.78 per tonne and to the social cost of carbon which is estimated in the range of $50 per tonne.[157] [158] The impact on the cost of generation from a new combined cycle unit of a $50 per tonne carbon price would be $16.85 per MWh.[159] The impact of an $800 per tonne carbon price would be $269.59 per MWh. This wide range of implied carbon prices is not consistent with an efficient, competitive, least cost approach to the reduction of carbon emissions.

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

PJM markets provide a flexible mechanism for incorporating the costs of environmental controls and meeting environmental requirements in a cost effective manner. Costs for environmental controls are part of offers for capacity resources in the PJM Capacity Market. The costs of emissions credits are included in energy offers. PJM markets also provide a flexible mechanism that incorporates renewable resources and the impacts of renewable energy credit markets, and ensures that renewable resources have access to a broad market. PJM markets provide efficient price signals that permit valuation of resources with very different characteristics when they provide the same product.

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

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

The annual average cost of complying with RPS over the nine year period from 2014 through 2022 for the ten jurisdictions that had RPS was $1.3 billion, or a total of $11.8 billion over nine years. The RPS compliance cost for 2022, the most recent year for which there is almost complete data, was $2.4 billion.[160]

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

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

159 The cost impact calculation assumes a heat rate of 6.296 MMBtu per MWh and a carbon emissions rate of 52.91 kg per MMBtu. The $800 per tonne carbon price represents the approximate upper end of the carbon prices implied by the 2022 REC and SREC prices in the PJM jurisdictions with RPS. Additional cost impacts are provided in Table 8-9.

160 The 2022 compliance cost value for PJM states does not include Delaware, Michigan or North Carolina. Based on past data these states generally account for approximately 2.0 percent of the total RPS compliance cost of PJM states.

RPS costs are payments by customers to the sellers of qualifying resources. The revenues from carbon pricing flow to the states.

If all the PJM states participated in a regional carbon market, the estimated revenue returned to the states/customers from selling carbon allowances would be approximately $6.9 billion per year if the carbon price were $19.76 per short ton and emissions levels were five percent below 2022 emission levels. If all the PJM states participated in a regional carbon market, the estimated revenue returned to the states/customers from selling carbon allowances would be approximately $17.5 billion if the carbon price were $50 per short ton and emission levels were five percent below 2022 levels. If only the current RPS states participated in a regional carbon market, the estimated revenue returned to the states/customers from selling carbon allowances at $19.76 per short ton would be about $4.6 billion. The costs of a carbon price are the impact on energy market prices, net of the revenue returned to states/customers.

Overview: Section 9, Interchange Transactions

Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Energy Market.** In the first three months of 2025, PJM was a monthly net exporter of energy in the real-time energy market in all months.[161] In the first three months of 2025, the real-time net interchange was -8,994.5 GWh. The real-time net interchange in the first three months of 2024 was -10,191.8 GWh.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** In the first three months of 2025, PJM was a monthly net exporter of energy in the day-ahead energy market in all months. In the first three months of 2025, the total day-ahead net interchange was -9,305.7 GWh. The day-ahead net interchange in the first three months of 2024 was -9,957.4 GWh.
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In the first three months of 2025, gross imports in the day-ahead energy market were 59.5 percent of gross imports in the real-time energy market (78.2 percent in the first three months of 2024). In the first three months of 2025, gross exports in the day-ahead energy market were 88.3 percent of the gross exports in the real-time energy market (92.2 percent in the first three months of 2024).
- **Interface Imports and Exports in the Real-Time Energy Market.** In the first three months of 2025, there were net scheduled exports at 12 of PJM's 19 interfaces in the real-time energy market.
- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In the first three months of 2025, there were net scheduled exports at five of PJM's seven interface pricing points eligible for real-time transactions in the real-time energy market.
- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the first three months of 2025, there were net scheduled exports at 15 of PJM's 19 interfaces in the day-ahead energy market.
- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the first three months of 2025, there were net scheduled exports at six of PJM's seven interface pricing points eligible for day-ahead transactions in the day-ahead energy market.
- **Up To Congestion Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the first three months of 2025, up to congestion transactions were net exports at four of PJM's seven interface pricing points eligible for day-ahead transactions in the day-ahead energy market.
- **Inadvertent Interchange.** In the first three months of 2025, net scheduled interchange was -8,994.5 GWh and net actual interchange was -8,911.7 GWh, a difference of 82.8 GWh. In the first three months of 2024, the difference was 9.6 GWh. This difference is inadvertent interchange.
- **Loop Flows.** In the first three months of 2025, the Northern Indiana Public Service (NIPS) Interface had the largest loop flows of any interface with -193.1 GWh of net scheduled interchange and -3,424.7 GWh of net actual interchange, a difference of 3,231.6 GWh. In the first three months of 2025, the SOUTH interface pricing point had the largest loop flows of any interface pricing point with 1,082.4 GWh of net scheduled interchange and 2,814.3 GWh of net actual interchange, a difference of 1,731.8 GWh.

161 Calculated values shown in Section 9, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In the first three months of 2025, the direction of the hourly flow was consistent with the real-time hourly price differences between the PJM/MISO Interface and the MISO/PJM Interface in 49.0 percent of the hours.
- **PJM and New York ISO Interface Prices.** In the first three months of 2025, the direction of the hourly flow was consistent with the real-time hourly price differences between the PJM/NYIS Interface and the NYISO/PJM proxy bus in 59.6 percent of the hours.
- **Neptune Underwater Transmission Line to Long Island, New York.** In the first three months of 2025, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Neptune Interface and the NYISO Neptune bus in 91.6 percent of the hours.
- **Linden Variable Frequency Transformer (VFT) Facility.** In the first three months of 2025, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Linden Interface and the NYISO Linden bus in 85.5 percent of the hours.
- **Hudson DC Line.** In the first three months of 2025, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Hudson Interface and the NYISO Hudson bus in 88.4 percent of the hours.

Interchange Transaction Issues

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued two TLRs of level 3a or higher in the first three months of 2025, and zero such TLRs in the first three months of 2024.
- **Up To Congestion.** The average number of up to congestion bids submitted in the day-ahead energy market increased by 43.3 percent, from 35,315 bids per day in the first three months of 2024 to 50,614 bids per day in the first three months of 2025. The average cleared volume of up to congestion bids submitted in the day-ahead energy market decreased by 18.9 percent, from 328,959 MWh per day in the first three months of 2024, to 266,942 MWh per day in the first three months of 2025.

Section 9 Recommendations

- The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU recommends that PJM apply after the fact market settlement adjustments to identified sham scheduling segments to ensure that market participants cannot benefit from sham scheduling. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule by concealing the true source or sink of the transaction. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on paths that reflect the expected actual power flow in order to reduce unscheduled loop flows. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that transactions sourcing in the Western Interconnection be priced at either the MISO interface pricing point or the SOUTH interface pricing point based on the locational price impact of flows between the DC tie line point of connection with the Eastern Interconnection and PJM. (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends that PJM eliminate the IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing authority to the MISO interface pricing point. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions. (Priority: Low. First reported 2009. Status: Adopted 2024.)

- The MMU recommends that PJM review the mappings of external balancing authorities to individual interface pricing points to reflect changes to the impact of the external power source on PJM tie lines as a result of system topology changes. The MMU recommends that this review occur at least annually. (Priority: Low. First reported 2009. Status: Not adopted.)
- The MMU recommends that, in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC. (Priority: Medium. First reported 2003. Status: Not adopted.)
- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that would remove the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized, but limited, joint dispatch approach that uses supply curves and treats seams between balancing authorities as constraints, similar to other constraints within an LMP market. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM permit unlimited spot market imports as well as unlimited nonfirm point to point willing to pay congestion imports and exports at all PJM interfaces in order to improve the efficiency of the market. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that the emergency interchange cap be replaced with a market based solution. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1800 on the day prior, to three hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes. These changes would give PJM a more flexible product that could be used to meet load in the most economic manner. (Priority: Medium. First reported 2014. Status: Partially adopted, 2015.)
- The MMU recommends eliminating the mechanism that defines FFE and M2M payments. These mechanisms are not consistent with markets and are not needed for efficient interface pricing. The MMU recommends that PJM file with the Commission to eliminate the FFE calculation and M2M payment of the PJM and MISO joint operating agreement. (Priority: Medium. First reported Q2 2024. Status: Not adopted.)
- The MMU recommends clear, explicit and detailed rules that define the conditions under which PJM will and will not recall energy from PJM capacity resources and prohibit new energy exports from PJM capacity resources. The MMU recommends that those rules define the conditions under which PJM will purchase emergency energy while at the same time not recalling energy exports from PJM capacity resources. The MMU recommends clear rules governing when PJM may recall capacity backed exports. (Priority: Medium. First reported 2010. Status: Partially adopted.)

Section 9 Conclusion

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

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

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

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

Overview: Section 10, Ancillary Services

Primary Reserve

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

Market Structure

- **Supply.** Primary reserve is provided by both synchronized reserve (generation or demand response currently synchronized to the grid and available within 10 minutes) and nonsynchronized reserve (generation currently offline but available to start and provide energy within 10 minutes).
- **Demand.** The primary reserve reliability requirement is equal to 150 percent of the synchronized reserve reliability requirement. The primary reserve requirement is equal to the primary reserve reliability requirement, with a shortage penalty price of $850 per MWh, plus the extended reserve requirement (190 MW), with a shortage penalty price of $300 per MWh. The synchronized reserve requirement is equal to the synchronized reserve reliability requirement plus the extended reserve requirement, with a default level of 190 MW. The synchronized reserve reliability requirement is normally equal to the most severe single contingency (MSSC). Starting in May 2023, PJM increased the size of the synchronized reserve reliability requirement in the RTO Reserve Zone by 30 percentage points to 130 percent of the most severe single contingency (MSSC), in effect increasing the primary reserve reliability requirement to 195 percent of the MSSC. In the first three months of 2025, the real-time average primary reserve requirement was 3,329.8 MW in the RTO Reserve Zone and 2,664.1 MW in the Mid-Atlantic Dominion Reserve Subzone.
- **Market Concentration.** Both the Mid-Atlantic Dominion (MAD) Reserve Subzone Market and the RTO Reserve Zone Market for primary reserve were characterized by structural market power in the first three months of 2025. The average HHI for real-time primary reserve in the RTO Reserve Zone was 1127, which is classified as moderately concentrated. The average HHI for day-ahead primary reserve in the RTO Zone was 992, which is classified as unconcentrated. The average HHI for real-time primary reserve in the MAD Reserve Subzone was 1805, which is classified as highly concentrated. The average HHI for day-ahead primary

reserve in the MAD Reserve Subzone was 1598, which is classified as moderately concentrated.

Synchronized Reserve Market

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

Market Structure

- **Supply.** In the first three months of 2025, the real-time average supply of available synchronized reserve was 5,697.3 MW in the RTO Zone, of which 2,938.5 MW on average was located in the Mid-Atlantic Dominion Reserve Subzone.
- **Demand.** The synchronized reserve requirement is equal to the synchronized reserve reliability requirement, with a shortage penalty price of $850 per MWh, plus the extended reserve requirement, with a shortage penalty price of $300 per MWh and a default value of 190 MW. The synchronized reserve reliability requirement is normally equal to the most severe single contingency (MSSC). Since May 19, 2023, PJM has inappropriately set the synchronized reserve reliability requirement to 130 percent of the MSSC for the RTO Reserve Zone. The real-time average synchronized reserve requirement in the first three months of 2025 was 2,283.2 MW in the RTO Reserve Zone and 1,839.4 MW in the Mid-Atlantic Dominion Reserve Subzone. The day-ahead average synchronized reserve requirement in the first three months of 2025 was 2,270.5 MW in the RTO Reserve Zone and 1,836.2 MW in the Mid-Atlantic Dominion Reserve Subzone.
- **Market Concentration.** The Mid-Atlantic Dominion (MAD) Reserve Subzone Market for synchronized reserve was characterized by structural market power in the first three months of 2025. The average HHI for real-time synchronized reserve in the RTO Reserve Zone was 1018, which is classified as moderately concentrated. The average HHI for day-ahead synchronized reserve in the RTO Zone was 871, which is classified as unconcentrated. The average HHI for real-time synchronized reserve in the MAD Reserve Subzone was 1839, which is classified as highly concentrated. The average HHI for day-ahead synchronized reserve in the MAD Reserve Subzone was 1423, which is classified as moderately concentrated.

Market Conduct

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

  Significant communications technology issues when calling resources during spinning events result in slow response.

Market Performance

- **Price.** In the first three months of 2025, for the Mid-Atlantic Dominion Reserve Subzone, the weighted average real-time price for synchronized reserve was $4.41 per MWh and the weighted average day-ahead price was $5.50 per MWh. In the first three months of 2025, for the RTO Reserve Zone, the weighted average real-time price for synchronized reserve was $3.82 per MWh and the weighted average day-ahead price was $5.74 per MWh.

Nonsynchronized Reserve

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

Market Structure

- **Supply.** In the first three months of 2025, the average supply of eligible and available nonsynchronized reserve was 1,078.1 MW in the RTO Reserve Zone, of which 698.9 MW on average was available in the Mid-Atlantic Dominion Reserve Subzone.
- **Demand.** Demand for nonsynchronized reserve is the primary reserve requirement less the amount of synchronized reserves cleared by PJM.[162] Although nonsynchronized reserve can be used to meet the 30-minute reserve requirement, any 30-minute reserve beyond the primary reserve requirement is usually provided by secondary reserves due to its lower cost and greater availability.

Market Conduct

- **Offers.** Generation owners do not submit supply offers for nonsynchronized reserve from non-hydroelectric units. Nonemergency generation resources that are available to provide energy and can start in 10 minutes or less are defined to be available for nonsynchronized reserves. For non-hydroelectric units, PJM calculates the MW available from a unit based on the unit's energy offer. Hydroelectric units set their own offered reserve amount. For all units, the offer price of nonsynchronized reserve is $0 per MWh.[163] Hybrid units and energy storage resources are not eligible to provide nonsynchronized reserves.

Market Performance

- **Price.** The nonsynchronized reserve price is determined by the marginal primary reserve resource. In the first three months of 2025, the nonsynchronized reserve weighted average real-time price for all intervals in the RTO Reserve Zone was $1.66 per MWh and the weighted average day-ahead price was $1.64 per MWh. In the first three months of 2025, the nonsynchronized reserve weighted average real-time price for all intervals in the MAD Reserve Subzone was $1.92 per MWh and the weighted average day-ahead price was $1.86 per MWh.

30-Minute Reserve Market

The supply of 30-minute reserves consists of resources, online or offline, which can respond within 30 minutes. This includes primary reserves and secondary reserves.

Market Structure

- **Supply.** The supply of 30-minute reserve is provided by both primary reserve (synchronized and nonsynchronized resources that can provide energy within 10 minutes) and secondary reserve (synchronized and nonsynchronized resources that can provide energy within 30 minutes but that take more than 10 minutes). In the first three months of 2025, the real-time average supply of available 30-minute reserve was 22,314.4 MW in the RTO Zone.
- **Demand.** The 30-minute reserve requirement is equal to the 30-minute reserve reliability requirement, with a shortage penalty price of $850 per MWh, plus the extended reserve requirement (190 MW), with a shortage penalty price of $300 per MWh. The 30-minute reserve reliability requirement is equal to the maximum of: the primary reserve reliability requirement; the largest active gas contingency; and 3,000 MW. Since PJM increased the synchronized reserve reliability requirement, the 30-minute

162 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.1 Overview of the PJM Reserve Markets, Rev. 133 (Dec. 17, 2024).

163 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.3 Reserve Market Resource Offer Structure, Rev. 133 (Dec. 17, 2024).

reserve reliability requirement is frequently equal to the primary reserve reliability requirement. In the first three months of 2025, the average 30-minute reserve requirement was 3,471.9 MW in the real-time market and 3,460.0 MW in the day-ahead market.

- **Market Concentration.** The RTO Reserve Zone Market for 30-minute reserves was characterized by moderate structural market power in the first three months of 2025. In the first three months of 2025, the average HHI for real-time 30-minute reserves was 976, which is classified as unconcentrated. In the first three months of 2025, the average HHI for day-ahead 30-minute reserves was 887, which is classified as unconcentrated.

Secondary Reserve

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

Market Structure

- **Supply.** In the first three months of 2025, the real-time average supply of available secondary reserve was 22,314.4 MW in the RTO Reserve Zone. As with the 30-minute reserve service, there is no defined reserve subzone for secondary reserves.
- **Demand.** Demand for secondary reserve is the 30-minute reserve requirement less the amount of primary reserves cleared by PJM.[164]

Market Conduct

- **Offers.** Energy storage resources, hydroelectric resources, hybrid resources, and demand-side response resources submit their available secondary reserve MW. For all other resource types, PJM calculates the MW available from a resource based on the resource's energy offer. For all resources, the offer price of secondary reserve is $0 per MWh.[165] In both the day-ahead and real-time secondary reserves markets, PJM uses lost opportunity costs as the offers and not offers submitted by market participants. For online secondary reserves, PJM calculates an opportunity cost based on LMP.

Market Performance

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

Regulation Market

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

PJM filed significant changes to the regulation market design on April 16, 2024 that were accepted as filed by order of June 17, 2024.[166] PJM will implement the changes to the regulation market in two phases. Phase 1, scheduled to be implemented on October 1, 2025, will result in a single product, single signal market with one clearing price. Phase 2, to be implemented on October

164 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.1 Overview of the PJM Reserve Markets, Rev. 133 (Dec. 17, 2024).

165 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.3 Reserve Market Resource Offer Structure, Rev. 133 (Dec. 17, 2024).

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

1, 2026, will result in separate regulation up and regulation down markets. The proposed Phase 1 changes will eliminate many of the significant issues identified by the MMU that have resulted from a two product, two signal market design including the incorrect and inconsistent use and application of the MBF/MRTS.

This report analyzes the current regulation market design and results during the first three months of 2025.

Market Structure

- **Supply.** In the first three months of 2025, the average hourly offered supply of regulation for nonramp hours was 779.4 performance adjusted MW (775.6 effective MW). This was an increase of 74.6 performance adjusted MW (an increase of 59.9 effective MW) from the first three months of 2024, when the average hourly offered supply of regulation was 704.8 actual MW (715.7 effective MW). In the first three months of 2025, the average hourly offered supply of regulation for ramp hours was 1,042.3 performance adjusted MW (1,099.4 effective MW). This was an increase of 83.2 performance adjusted MW (an increase of 77.6 effective MW) from the first three months of 2024, when the average hourly offered supply of regulation was 959.1 performance adjusted MW (1,021.9 effective MW).
- **Demand.** The hourly regulation demand is 525.0 effective MW for nonramp hours and 800.0 effective MW for ramp hours.
- **Supply and Demand.** The nonramp regulation requirement of 525.0 effective MW was provided by a combination of cleared RegA and RegD resources equal to 488.5 hourly average performance adjusted actual MW in the first three months of 2025. This is an increase of 10.1 performance adjusted actual MW from the first three months of 2024, when the average hourly total regulation cleared performance adjusted actual MW for nonramp hours were 478.4 performance adjusted actual MW. The ramp regulation requirement of 800.0 effective MW was provided by a combination of cleared RegA and RegD resources equal to 693.6 hourly average performance adjusted actual MW in the first three months of 2025. This is a decrease of 1.8 performance adjusted actual MW from the first three months of 2024, where the average hourly regulation cleared MW for ramp hours were 695.3 performance adjusted actual MW.

  The ratio of the average hourly offered supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for nonramp hours was 1.59 in the first three months of 2025 (1.47 in the first three months of 2024). The ratio of the average hourly offered supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for ramp hours was 1.50 in the first three months of 2025 (1.38 in the first three months of 2024).
- **Market Concentration.** In the first three months of 2025, the three pivotal supplier test was failed in 94.5 percent of hours. In the first three months of 2025, the effective MW weighted average HHI of RegA resources was 2489 which is highly concentrated and the effective MW weighted average HHI of RegD resources was 1892 which is also highly concentrated. The effective MW weighted average HHI of all resources was 1235, which is moderately concentrated.

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. Owners are required to submit a cost-based offer and may submit a price-based offer. Offers include both a capability offer and a performance offer. Owners must specify which signal type the unit will be following, RegA or RegD.[167] In the first three months of 2025, there were 189 resources following the RegA signal and 58 resources following the RegD signal.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $46.64 per MW of regulation in the first three months of 2025, an increase of $18.64 per MW, or 66.6 percent, from the weighted average clearing price of $28.00 per MW in the first three months of 2024. The weighted average cost of regulation in the first three months of 2025 was $58.86 per MW of regulation, an increase of 65.6 percent, from the weighted average cost of $35.55 per MW in the first three months of 2024.

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

- **Prices.** RegD resources continue to be incorrectly compensated relative to RegA resources due to an inconsistent application of the marginal benefit factor in the optimization, assignment and settlement processes. If the regulation market were functioning efficiently and competitively, RegD and RegA resources would be paid the same price per effective MW.
- **Marginal Benefit Factor.** The marginal benefit factor (MBF) is intended to measure the operational substitutability of RegD resources for RegA resources. The marginal benefit factor is incorrectly defined and applied in the PJM market clearing. The current incorrect and inconsistent implementation of the MBF has resulted in the PJM Regulation Market over procuring RegD relative to RegA in most hours and in an inefficient market signal about the value of RegD in every hour.

Black Start Service

Black start service is required for the reliable restoration of the grid following a blackout. Black start service is the ability of a generating unit to start without an outside electrical supply, or is the demonstrated ability of a generating unit to automatically remain operating at reduced levels when disconnected from the grid (automatic load rejection or ALR).[168]

In the first three months of 2025, total black start charges were $15.9 million, including $15.9 million in revenue requirement charges and $0.002 million in uplift charges. Black start revenue requirements consist of fixed black start service costs, variable black start service costs, training costs, fuel storage costs, and an incentive payment. Black start uplift charges are paid to units scheduled in the day-ahead energy market or committed in real time to provide black start service under the ALR option or for black start testing. Black start zonal charges in the first three months of 2025 ranged from $0 in the OVEC and REC Zones to $2.4 million in the AEP Zone.

CRF values are a key determinant of total payments to black start units. The CRF values in PJM tariff tables should have been changed for both black start and the capacity market when the tax laws changed effective January 1, 2018. As a result of the failure to reduce the CRF values, black start units have been and continue to be significantly overcompensated since the changes to the tax code. In March 2023, FERC issued an order establishing hearing and settlement judge procedures.[169] Hearing procedures have been terminated while the Commission's consideration of settlement options is pending.

Reactive

Reactive service, reactive supply and voltage control are provided by generation and other sources of reactive power (measured in MVAr). Reactive power helps maintain appropriate voltage levels on the transmission system and is essential to the flow of real power (measured in MW). The same equipment provides both MVAr and MW. Generation resources are required to meet defined reactive capability requirements as a condition to receive interconnection service in PJM.[170] RTOs and their customers are not required to separately compensate generation resources for such reactive capability.[171] In the first three months of 2025, PJM customers paid $92.9 million for reactive capability based on archaic, nonmarket and unsupported assertions about cost allocation and a regulatory review process of filings by individual units that results in unsupported black box settlements. The current rules have permitted over recovery of reactive costs through reactive capability charges. All costs of generators should be incorporated in the market.

The nonmarket approach to reactive capability payments will be eliminated effective June 1, 2026, based on FERC's Order No. 904.[172]

Reactive service charges based on opportunity costs are appropriately paid to units that operate in real time outside of their normal range at the direction of PJM for the purpose of providing real-time reactive power.

Total reactive charges decreased 2.78 percent from $96.1 million in the first three months of 2024 to $93.4 million in the first three months of 2025.

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

169 182 FERC ¶ 61,194 (2023).

170 OATT Attachment O.

171 *See* 182 FERC ¶ 61,033 at P 52 (January 27, 2023); *see also Standardization of Generator Interconnection Agreements & Procedures*, Order No. 2003, 104 FERC ¶ 61,103 at P 546 (2003), *order on reh'g*, Order No. 2003-A, 106 FERC ¶ 61,220 at P 28, *order on reh'g*, Order No. 2003-B, 109 FERC ¶ 61,287 (2004), *order on reh'g*, Order No. 2003-C, 111 FERC ¶ 61,401 (2005), *aff'd sub nom. National Association of Regulatory Utility Commissioners v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007); *California ISO*, 160 FERC ¶ 61,035 at P 19 (2017); 119 FERC ¶ 61,199 at P 28 (2007), *order on reh'g*, 121 FERC ¶ 61,196 (2007); *see also* 178 FERC ¶ 61,088, at PP 29–31 (2022); 179 FERC ¶ 61,103, at PP 20-21 (2022).

172 *Compensation for Reactive Power within the Standard Power Factor Range*, Order No. 904, 189 FERC ¶ 61,034 (2024); PJM compliance filing, Docket No. ER24-1073 (January 28, 2025).

Reactive capability charges decreased 2.42 percent from $95.2 million in 2024 to $92.9 million in the first three months of 2025. Total zonal reactive service charges ranged from $0 in the REC and OVEC Zones, to $14.3 million in the AEP Zone in the first three months of 2025.

Frequency Response

The PJM Tariff requires that all new generator interconnection customers, both synchronous and nonsynchronous, have hardware and/or software that provides primary frequency responsive real power control with the ability to sense changes in system frequency and autonomously adjust real power output to correct for frequency deviations.[173] Primary frequency response begins within a few seconds and extends up to a minute. The purpose of primary frequency response is to arrest and stabilize the system until other measures (secondary and tertiary frequency response) become active. This includes a governor or equivalent controls capable of operating with a maximum five percent droop and a +/- 36 mHz deadband.[174] In addition to resource capability, resource owners must comply by setting control systems to autonomously adjust real power output in a direction to correct for frequency deviations.

The response of generators within PJM to NERC identified frequency events remains under evaluation. A frequency event is declared whenever the system frequency goes outside of 60 Hz by +/- 40 mHz and stays there for 60 continuous seconds. Effective June 2024 through May 2025, the NERC BAL-003-2 requirement for balancing authorities (PJM is a balancing authority) uses a threshold value (L_{10}) equal to +/- 258.3 MW/0.1 Hz.[175]

As a balancing authority, PJM requires all generators to be capable of providing primary frequency response and to operate with primary frequency response controls enabled.[176] [177] PJM does monitor primary frequency response during NERC identified frequency events for all resources 50 MW or greater. Exclusions to PJM monitoring include nuclear plants, offline units, units with no available headroom, units assigned to regulation, and units with a current outage ticket in eDART.

Market Procurement of Real-Time Ancillary Services

PJM uses market mechanisms to varying degrees in the procurement of ancillary services, including primary reserves, secondary reserves, and regulation. Ideally, all ancillary services would be procured taking full account of the interactions with the energy market. When a resource is used for an ancillary service instead of providing energy in real time, the cost of removing the resource, either fully or partially, from the energy market should be included in the offer for the ancillary service. The degree to which PJM markets account for these interactions depends on the timing of the product clearing, software limitations, and the accuracy of unit parameters and offers.

The synchronized reserve market clearing is more integrated with the energy market clearing than the other ancillary services. Synchronized reserves are jointly cleared with energy in every real-time market solution. Given the joint clearing of energy and flexible synchronized reserves, the synchronized reserve market clearing price should always cover the opportunity cost of providing flexible synchronized reserves. Inflexible synchronized reserves, provided by resources that require hourly commitments due to run-time or staffing constraints, are not cleared with energy in the real-time market solution.[178] Instead, inflexible synchronized reserves are cleared hourly by the Ancillary Service Optimizer (ASO) or the day-ahead energy market. The ASO considers energy market price forecasts, availability of resources for flexible synchronized reserves, and regulation requirements to estimate the costs and benefits of using a resource for inflexible synchronized reserves. The ASO selected inflexible reserves are a fixed input to RT SCED, which clears the balance of the requirement with flexible synchronized reserves.

Nonsynchronized reserves and offline secondary reserves are cleared with every real-time energy market solution. The energy commitment decisions to keep the resources offline have already been made when the RT SCED

173 Nuclear Regulatory Commission (NRC) regulated facilities are exempt from this provision. Behind the meter generation that is sized to load is also exempt.
174 OATT Attachment O § 4.7.2 (Primary Frequency Response).
175 See NERC. "2024 Frequency Bias Settings," June 11, 2024. <https://www.nerc.com/comm/OC/Documents/OY_2024_Frequency_Bias_Annual_Calculations_correction_06112024.pdf>.
176 OATT Attachment O § 4.7.2 (Primary Frequency Response).
177 See PJM. "PJM Manual 12: Balancing Operations," § 3.6 Primary Frequency Response, Rev. 54 (Dec. 17, 2024).
178 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.4.3 Reserve Market Clearing, Rev. 133 (Dec 17, 2024).

clears the five-minute reserves markets. Therefore, offline reserves have no lost opportunity cost. They will not be called on for energy during the market interval for which they are assigned as offline resources.

Prices for the regulation and reserve markets are set by the pricing calculator (LPC), which uses the RT SCED solution as an input. The LPC includes fast start pricing logic and system marginal price caps, so the final prices can be inconsistent with the marginal cost of the resources that clear regulation and reserves.

Section 10 Recommendations

Reserve Markets

- The MMU recommends that to minimize lag and improve performance, PJM use an electronic synchronized reserve event notification process for all resources and that all resources be required to have the ability to receive and respond to the notifications. (Priority: Medium. First reported 2023. Status: Partially adopted December 17, 2024.)
- The MMU recommends that PJM replace the Mid-Atlantic Dominion Reserve Subzone with a reserve zone structure consistent with the actual deliverability of reserves based on current transmission constraints. (Priority: High. First reported 2019. Status: Partially adopted October 1, 2022.)
- The MMU recommends that the components of the cost-based offers for providing regulation and synchronous condensing be defined in Schedule 2 of the Operating Agreement. (Priority: Low. First reported 2019. Status: Not adopted.)
- The MMU recommends that, for calculating the penalty for a synchronized reserve resource failing to meet its scheduled obligation during a spinning event, the unit repay all credits back to the last time that the unit successfully responded to an event 10 minutes or longer. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that, for calculating the penalty for a synchronized reserve resource failing to meet its scheduled obligation during a spinning event, the synchronized reserve shortfall penalty should include LOC payments as well as SRMCP and MW of shortfall. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that aggregation not be permitted to offset unit specific penalties for failure to respond to a synchronized reserve event. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM immediately remove the 30 percent increase to the synchronized reserve reliability requirement. (Priority: High. First reported 2024. Status: Not adopted.)

Regulation Market

- The MMU recommends that the two signal regulation market design be replaced with a one signal regulation market design. (Priority: Medium. First reported 2023. Status: Not adopted.)[179]
- The MMU recommends that the ability to make dual offers (to make offers as both a RegA and a RegD resource in the same market hour) be removed from the regulation market. (Priority: High. First reported 2019. Status: Not adopted.)[180]
- The MMU recommends that the regulation market be modified to incorporate a consistent application of the marginal benefit factor (MBF) throughout the optimization, assignment and settlement process. The MBF should be defined as the Marginal Rate of Technical Substitution (MRTS) between RegA and RegD. (Priority: High. First reported 2012. Status: Not adopted. FERC rejected.[181])[182]
- The MMU recommends that the current calculation of the performance score (based on precision, delay and correlation metrics) be replaced with the current calculation of the precision score. (Priority: Medium. First reported 2023. Status: Not adopted.).

179 PJM filed proposed changes to the regulation market with the FERC on April 16, 2024 (Regulation Market Design Filing," Docket No. ER24-1772-000). The Commission Order on June 17, 2024 accepted the PJM Proposal as filed. PJM will implement the changes to the regulation market in two phases. Phase 1, scheduled to be implemented on October 1, 2025, will result in a single signal, bidirectional market with one clearing price that eliminates the need for an MBF. Phase 1 will eliminate RegA and RegD dual offers. Phase 1 will reduce the regulation commitment period from a 60-minute commitment to a 30-minute commitment. In Phase 1 the lost opportunity cost calculation used in the regulation market will be based on the resource's dispatched energy offer schedule, not the lower of its price or cost offer schedule.

180 Id.

181 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).

182 Id.

- The MMU recommends that the regulation market commitment period be reduced from a 60-minute commitment to a 30-minute commitment. (Priority: Medium. First reported 2023. Status: Not adopted.).[183]
- The MMU recommends that the lost opportunity cost in the ancillary services markets be calculated using the schedule on which the unit was scheduled to run in the energy market. (Priority: High. First reported 2010. Status: Not adopted.[184] FERC rejected.)[185]
- The MMU recommends that the lost opportunity cost calculation used in the regulation market be based on the resource's dispatched energy offer schedule, not the lower of its price or cost offer schedule. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected.)[186] [187]
- The MMU recommends that the $12.00 margin adder be eliminated from the definition of the cost based regulation offer because it is a markup and not a cost. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that the ramp rate limited desired MW output be used in the regulation uplift calculation, to reflect the physical limits of the unit's ability to ramp and to eliminate overpayment for opportunity costs when the payment uses an unachievable MW. (Priority: Medium. First reported 2022. Status: Not adopted.)[188]
- The MMU recommends enhanced documentation of the implementation of the regulation market design. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected.)[189]
- The MMU recommends that PJM be required to save data elements necessary for verifying the performance of the regulation market. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that all data necessary to perform the regulation market three pivotal supplier test be saved by PJM so that the test can be replicated. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that the total regulation (TReg) signal sent on a fleet wide basis be eliminated and replaced with individual regulation signals for each unit. (Priority: Low. First reported 2019. Status: Not adopted.)
- The MMU recommends that, to prevent gaming, there be a penalty enforced in the regulation market as a reduction in performance score and/or a forfeiture of revenues when resource owners elect to deassign assigned regulation resources within the hour. (Priority: Medium. First reported 2016. Status: Not adopted. FERC rejected.)[190]

Frequency Response, Reactive, and Black Start

- The MMU recommends that all resources, new and existing, have a requirement to include and maintain equipment for primary frequency response capability as a condition of interconnection service. The PJM markets already compensate resources for frequency response capability and any marginal costs. (Priority: Medium. First reported 2018. Status: Partially adopted.)
- The MMU recommends that all data necessary to perform the generator primary frequency response evaluation be saved by PJM so that the test can be replicated. (Priority: Medium. First reported 2023. Status: Not adopted.)
- The MMU recommends that PJM maintain a full list of all units subject to the Primary Frequency Response generator requirements. (Priority: Medium. New Recommendation. Status: Not adopted.)
- The MMU recommends that PJM create the necessary tariff/manual language to properly enforce compliance with the NERC mandated Primary Frequency Response generator requirements. (Priority: Medium. New Recommendation. Status: Not adopted.)

183 Id.
184 This recommendation was adopted by PJM for the energy market. Lost opportunity costs in the energy market are calculated using the schedule on which the unit was scheduled to run. In the regulation market, this recommendation has not been adopted, as the LOC continues to be calculated based on the lower of price or cost in the energy market offer.
185 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).
186 *Id.*
187 Id.
188 In Phase 1 the ramp rate limited desired MW output will be used in the regulation uplift calculation. The MMU does not agree with how this change will be implemented and will be reviewing the market results in Phase 1.
189 *Id.*
190 *Id.*

- The MMU recommends that separate cost of service payments for reactive capability be eliminated and the cost of reactive capability be recovered in PJM markets. (Priority: Medium. First reported 2016. Status: Not adopted.)[191]
- The MMU recommends that payments for reactive capability, if continued, be based on the 0.95 power factor included in the voltage schedule in Interconnection Service Agreements. (Priority: Medium. First reported 2018. Status: Not adopted.)[192]
- The MMU recommends that, if payments for reactive are continued, fleet wide cost of service rates used to compensate resources for reactive capability be eliminated and replaced with compensation based on unit specific costs. (Priority: Low. First reported 2019. Status: Not adopted.)[193]
- The MMU recommends that, if payments for reactive are continued, Schedule 2 to OATT be revised to state explicitly that only generators that provide reactive capability to the transmission system that PJM operates and has responsibility for are eligible for reactive capability compensation. (Priority: Medium. First reported 2020. Status: Not adopted.)[194]
- The MMU recommends that new CRF rates for black start units, incorporating current tax code changes, be implemented immediately. The new CRF rates should apply to all black start units. Black start units should be required to commit to providing black start service for the life of the unit. (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends that black start planning and coordination be on a regional basis and not on a zonal basis and that the costs of black start service be shared on an equal per MWh basis across the region. (Priority: Medium. First reported 2023. Status: Not adopted.)

191 On October 17, 2024, the Commission issued a final rule, Order No. 904, eliminating separate payments for reactive in all jurisdictional markets, including PJM. On January 28, 2025, PJM submitted a compliance filing to implement Order No. 904 ("Compliance Filing") that proposed a transition mechanism lasting through May 31, 2026. See Docket No. ER25-1073.

192 Id.

193 Id.

194 Id.

Section 10 Conclusion

The October 1, 2022, changes to the reserve markets included a synchronized reserve must offer requirement applicable to all generation capacity resources. This resulted in an increase in available supply. Combined with the removal of the $7.50 per MWh margin and the invalid variable operations and maintenance cost, supply and demand logic predicts lower prices, which occurred in 2022, except during Winter Storm Elliott. This is evidence of market efficiency. With the elimination of tier 1 reserves, the total reserve market clearing price credits, while based on lower prices, are paid to a larger MW quantity. However, prices have been higher since PJM increased the demand for reserves in May 2023.

The new reserve market design has been called into question by PJM based on a slow response during synchronized reserve events. In all cases, other than during Winter Storm Elliott, the ACE recovered within the required time frame. No reliability problems have occurred. While the total response met the needs of the system, PJM responded to the poor performance of individual units by unilaterally and inappropriately increasing reserve requirements. This increase shifts the burden of poor resource performance from the resources themselves to customers, clearing more reserves instead of directly dealing with the causes of poor performance. These increases were the primary cause of higher reserve prices in 2023, 2024, and the first three months of 2025, including 35 intervals of shortage pricing in May 2023 and several intervals of shortage pricing during spin events on January 29, 2024, June 3, 2024, July 8, 2024, February 5, 2025, and February 11, 2025, even while reserve markets cleared over 1,000 MW more than what was normally cleared in the months and years prior.

The data on synchronized reserve event recovery do not support the conclusion that there was or is a need to increase the demand for reserves. The focus should be on correcting issues related to the responses of individual units rather than increasing demand.

The immediate solution is to improve the deployment of reserves in synchronized reserve events by requiring the capability to use an electronic signal for all synchronized reserves. The archaic telephone communications technology has been a source of slow response times. Phone calls are not an effective or efficient method for deploying resources for immediate response. The MMU recommends that to minimize lag and improve performance, PJM use an electronic synchronized reserve event notification process for all resources and that all resources be required to have the ability to receive and respond to the notifications. On December 17, 2024, PJM partially adopted this recommendation by implementing an electronic deployment of reserves via an augmented dispatch signal, but PJM does not require that resources be able to receive this signal. Further improvements in communications technology are necessary and PJM should pursue them immediately.

Along with changes to the communications and deployment process, PJM and the MMU have worked with generators to identify circumstances where reserves were not accurately measured based on the energy and reserve offer parameters. More broadly, the MMU's proposal is to buy the correct amount of reserves. No increase in demand is required. There has been no change in the need/demand for reserves. PJM ignored the supply side. The issue is that resources have not provided the reserves that were offered and paid for. With the improved communications, instead of buying more MW of poorly performing reserves, PJM will be able to accurately recognize the actual supply of reserves and to more efficiently deploy them in synchronized reserve events. PJM should immediately remove the 30 percent increase to the synchronized reserve reliability requirement in place from May 2023 through March 2025.

The design of the current PJM Regulation Market is significantly flawed.[195] The market design does not correctly incorporate the marginal rate of technical substitution (MRTS) in market clearing and settlement. The market design uses the marginal benefit factor (MBF) to incorrectly represent the MRTS and uses a mileage ratio instead of the MBF in settlement. The current market design allows regulation units that have the capability to provide both RegA and RegD MW to submit an offer for both signal types in the same market hour. However, the method of clearing the regulation market for an hour in which one or more units has a dual offer incorrectly accounts for the amount of RegD and the effective MW of the RegD that it clears. The result of the flaw is that the MBF in the clearing phase is incorrectly low compared to the MBF in the solution phase and the actual amount of effective MW procured is higher than the regulation requirement. This failure to correctly and consistently incorporate the MRTS into the regulation market design has resulted in both underpayment and overpayment of RegD resources and in the over procurement of RegD resources in all hours. Under the current design, slower response RegA resources (generating units) must provide additional regulation to offset the negative impact of RegD resources (largely batteries) that are charging in the middle of a regulation hour. The ability of some resources to submit offers for both RegA and RegD (dual offers) results in inefficient high prices. The market results continue to include the incorrect definition of opportunity cost. These issues are the basis for the MMU's conclusion that the regulation market design is flawed.

PJM filed proposed changes to the regulation market with the FERC on April 16, 2024.[196] The MMU filed a protest to the PJM filing on May 7, 2024, and answer to PJM's answer on June 7, 2024. The Commission Order on June 17, 2024 accepted the PJM Proposal as filed. PJM will implement the changes to the regulation market in two phases. Phase 1, scheduled to be implemented on October 1, 2025, will result in a single signal, bidirectional market with one clearing price. Phase 2, to be implemented on October 1, 2026, will result in separate regulation up and regulation down markets. The proposed changes to move to a single signal market, as approved by FERC, will eliminate the issues caused by the incorrect and inconsistent use and application of the MBF/MRTS in the regulation market.

The benefits of markets can be realized under the current approach to ancillary service markets. Even in the presence of structurally noncompetitive markets, there can be transparent, market clearing prices based on competitive offers that account explicitly and accurately for opportunity cost. This is consistent with the market design goal of ensuring competitive outcomes that provide appropriate incentives without reliance on the exercise of market power and

195 The current PJM regulation market design that incorporates two signals using two resource types was a result of FERC Order No. 755 and subsequent orders. Order No. 755, 137 FERC ¶ 61,064 at PP 197–200 (2011).

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

with explicit mechanisms to prevent the exercise of market power. However, there are significant issues with the PJM ancillary services markets.

The MMU concludes that the synchronized reserve market results were not competitive. The MMU concludes that the nonsynchronized reserve market results were competitive. The MMU concludes that the secondary reserve market results were competitive. The MMU concludes that the regulation market results were not competitive, and the market design is significantly flawed.

Overview: Section 11, Congestion and Marginal Losses

Congestion Cost

- **Total Congestion.** Total congestion costs increased by $182.3 million or 56.8 percent, from $321.0 million in the first three months of 2024 to $503.3 million in the first three months of 2025.
- **Day-Ahead Congestion.** Day-ahead congestion costs increased by $304.8 million or 76.4 percent, from $398.7 million in the first three months of 2024 to $703.5 million in the first three months of 2025.
- **Balancing Congestion.** Negative balancing congestion costs increased by $122.5 million, from -$77.7 million in the first three months of 2024 to -$200.2 million in the first three months of 2025. Negative balancing explicit charges increased by $42.7 million, from -$51.8 million in the first three months of 2024 to -$94.5 million in the first three months of 2025.
- **Real-Time Congestion.** Real-time congestion costs increased by $463.7 million, from $390.5 million in the first three months of 2024 to $854.2 million in the first three months of 2025.
- **Monthly Congestion.** Monthly total congestion costs in the first three months of 2025 ranged from $124.5 million in February to $227.8 million in January.
- **Geographic Differences in CLMP.** Differences in CLMP between southern and eastern control zones in PJM were primarily a result of binding constraints on the Lenox – North Meshoppen Line, the AP South Interface, the Dune Acres – Michigan City Flowgate, the Chaparral – Carson Line, and the AEP – DOM Interface.
- **Congestion Frequency.** Congestion frequency continued to be significantly higher in the day-ahead energy market than in the real-time energy market in the first three months of 2025. The number of congestion event hours in the day-ahead energy market was about three times the number of congestion event hours in the real-time energy market.

  Day-ahead congestion frequency increased by 7.4 percent from 19,390 congestion event hours in the first three months of 2024 to 20,823 congestion event hours in the first three months of 2025.

  Real-time congestion frequency increased by 34.2 percent from 6,273 congestion event hours in the first three months of 2024 to 8,416 congestion event hours in the first three months of 2025.
- **Congested Facilities.** Day-ahead, congestion event hours decreased on transformers and lines and increased on interfaces and flowgates.

  The Lenox – North Meshoppen Line was the largest contributor to congestion costs in the first three months of 2025. With $88.3 million in total congestion costs, it accounted for 17.5 percent of the total PJM congestion costs in the first three months of 2025.
- **CT Price Setting Logic and Closed Loop Interface Related Congestion.** PJM's use of CT pricing logic officially ended with the implementation of fast start pricing on September 1, 2021. While CT pricing logic was officially discontinued, PJM continues to use a related logic to force inflexible units and demand response to be on the margin in both real time and day ahead. None of the PJM defined closed loop interfaces were binding in the first three months of 2024 or 2025.
- **Zonal Congestion.** AEP had the highest zonal congestion costs among all control zones in the first three months of 2025. AEP had $81.9 million in zonal congestion costs, comprised of $111.1 million in day-ahead congestion costs and -$29.2 million in balancing congestion costs.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs increased by $211.9 million or 97.7 percent, from $217.0 million in the first three months of 2024 to $428.9 million in the first three months of 2025. The loss MWh in PJM increased by 682.0 GWh or 16.6 percent, from 4,112.8 GWh in the first three months of 2024 to 4,794.8 GWh in the first three months of 2025. The loss component of real-time LMP in the first three months of 2025 was $0.04, compared to $0.02 in the first three months of 2024.
- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs increased by $213.5 million or 90.4 percent, from $236.2 million in the first three months of 2024 to $449.7 million in the first three months of 2025.
- **Balancing Marginal Loss Costs.** Negative balancing marginal loss costs increased by $1.6 million or 8.1 percent, from -$19.3 million in the first three months of 2024 to -$20.8 million in the first three months of 2025.
- **Total Marginal Loss Surplus.** The total marginal loss surplus increased by $85.9 million or 120.4 percent, from $71.4 million in the first three months of 2024, to $157.3 million in the first three months of 2025.
- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in the first three months of 2025 ranged from $90.2 million in March to $222.8 million in January.

System Energy Cost

- **Total System Energy Costs.** Total system energy costs decreased by $125.3 million or 86.1 percent, from -$145.6 million in the first three months of 2024 to -$270.9 million in the first three months of 2025.
- **Day-Ahead System Energy Costs.** Day-ahead system energy costs decreased by $131.8 million or 75.1 percent, from -$175.6 million in the first three months of 2024 to -$307.5 million in the first three months of 2025.
- **Balancing System Energy Costs.** Balancing system energy costs increased by $9.6 million or 32.4 percent, from $29.5 million in the first three months of 2024 to $39.0 million in the first three months of 2025.
- **Monthly Total System Energy Costs.** Monthly total system energy costs in the first three months of 2025 ranged from -$137.8 million in January to -$56.9 million in March.

Section 11 Conclusion

Congestion is defined as the total payments by load in excess of the total payments to generation, excluding marginal losses. The level and distribution of congestion reflects the underlying characteristics of the power system, including the nature and defined capability of transmission facilities, the offers and geographic distribution of generation facilities, the level and geographic distribution of incremental bids and offers and the geographic and temporal distribution of load.

Total congestion costs increased by $182.3 million or 56.8 percent, from $321.0 million in the first three months of 2024 to $503.3 million in the first three months of 2025.

Monthly total congestion costs ranged from $124.5 million in February to $227.8 million in January in the first three months of 2025.

The current ARR/FTR design does not ensure that load receives the rights to all congestion revenues. The congestion offset provided by ARRs and self-scheduled FTRs in the first ten months of the 2024/2025 planning period was 51.3 percent. The cumulative offset of congestion by ARRs for the 2011/2012 planning period through the first ten months of the 2024/2025 planning period, using the rules effective for each planning period, was 68.7 percent. Load has received $4.8 billion less than load should have received from the 2011/2012 planning period through the first ten months of the 2024/2025 planning period.

Overview: Section 12, Generation and Transmission Planning

Generation Interconnection Planning

Existing Generation Mix

- As of March 31, 2025, PJM had a total installed capacity of 199,092.6 MW, of which 38,366.4 MW (19.3 percent) are coal fired steam units, 56,124.2 MW (28.2 percent) are combined cycle units and 33,452.6 MW (16.8 percent) are nuclear units. This measure of installed capacity differs from capacity market installed capacity because it includes energy only units, excludes all external units, and uses nameplate values for solar and wind resources.
- Of the 199,092.6 MW of installed capacity, 69,815.2 MW (35.1 percent) are from units older than 40 years, of which 30,814.3 MW (44.1 percent) are coal fired steam units, 191.0 MW (0.3 percent) are combined cycle units and 23,264.6 MW (33.3 percent) are nuclear units.

Generation Retirements[197]

- There are 62,810.2 MW of generation that have been, or are planned to be, retired between 2011 and 2028, of which 45,302.8 MW (72.1 percent) are coal fired steam units.
- In the first three months of 2025, 410.0 MW of generation retired. The largest generator that retired in the first three months of 2025 was the 410.0 MW Indian River 4 coal fired steam unit located in the DPL Zone. Of the 410.0 MW of generation that retired in the first three months of 2025, 410.0 MW (100.0 percent) were located in the DPL Zone.
- As of March 31, 2025, there are 7,654.9 MW of generation that have requested retirement after March 31, 2025, of which 2,700.0 MW (35.3 percent) are located in the AEP Zone. Of the generation requesting retirement in the AEP Zone, 2,620.0 MW (97.0 percent) are coal fired steam units.

197 See PJM. Planning. "Generator Deactivations," (Accessed on March 31, 2025) <https://www.pjm.com/planning/service-requests/gen-deactivations>.

Generation Queue[198]

- On November 29, 2022, the Commission issued an order accepting PJM's tariff revisions to improve the queue process.[199] The new queue process includes modifications to implement a cluster/cycle based processing method to replace the first in/first out processing method.[200] This change will allow projects to move forward based on a first ready/first out analysis, where readiness is demonstrated through site control and financial milestones and there is an option to exit the study process early based on system impacts. The transition to the new queue process began on July 10, 2023.
- As of March 31, 2025, a total of 167,067.4 MW, on an energy basis, were in generation request queues in the status of active, under construction or suspended.[201] Based on historical completion rates, 33,489.2 MW (20.0 percent), on an energy basis, of new generation in the queue are expected to go into service. As projects move through the queue process, projects can be removed from the queue due to incomplete or invalid data, withdrawn by the market participant or placed in service.
- Of the 7,664.8 MW, on an energy basis, of combined cycle projects in the queue, 4,194.3 MW (54.7 percent) are expected to go in service based on historical completion rates as of March 31, 2025.
- Of the 37,000.4 MW, on an energy basis, of battery projects in the queue, only 1,294.3 MW (3.5 percent) are expected to go in service based on historical completion rates as of March 31, 2025.
- Of the 120,350.5 MW, on an energy basis, of renewable projects in the queue, 26,775.4 MW (22.3 percent) are expected to go in service based on historical completion rates as of March 31, 2025.
- Of the 7,463.1 MW, on a capacity basis that requested CIRs, of combined cycle projects requested in the generation queues in the status of active, under construction or suspended, 3,987.1 MW (53.3 percent) are expected

198 See PJM. Planning. "New Services Queue," (Accessed on March 31, 2025) <https://www.pjm.com/planning/service-requests/serial-service-request-status>.

199 See 181 FERC ¶ 61,162 (2022).

200 See "Interconnection Process Reform," presented at April 27, 2022 meeting of the Members Committee. <https://www.pjm.com/-/media/committees-groups/committees/mc/2022/20220427/20220427-item-01a-1-interconnection-process-reform-presentation.ashx>.

201 Unless otherwise noted, the queue totals in this report are the winter net MW energy for the interconnection requests ("MW Energy") as shown in the queue.

to go into service based on historical completion rates. Based on historical completion rates and the ELCC derate factors using the class ratings for the 2026/2027 Base Residual Auction,[202] the 7,463.1 MW of capacity requests currently under construction, suspended or active in the queue would be reduced to 2,943.8 MW of capacity (39.4 percent of the total requested capacity).[203]

- Of the 32,993.3 MW, on a capacity basis that requested CIRs, of battery projects requested in the generation queues in the status of active, under construction or suspended, 194.7 MW (0.6 percent) are expected to go into service based on historical completion rates. Based on historical completion rates and the ELCC derate factors using the class ratings for the 2026/2027 Base Residual Auction,[204] the 32,993.3 MW of capacity requests currently under construction, suspended or active in the queue would be reduced to 97.3 MW of capacity (0.3 percent of the total requested capacity).[205]
- Of the 65,103.4 MW, on a capacity basis that requested CIRs, of renewable projects requested in the generation queues in the status of active, under construction or suspended, 13,240.3 MW (20.3 percent) are expected to go into service based on historical completion rates. Based on historical completion rates and the ELCC derate factors using the class ratings for the 2026/2027 Base Residual Auction,[206] the 65,103.4 MW of capacity requests currently under construction, suspended or active in the queue would be reduced to 1,844.2 MW of capacity (2.8 percent of the total requested capacity).[207]
- As of March 31, 2025, 107,595.6 MW of capacity requests (requested CIRs) were in the generation queues in the status of active, under construction or suspended. Based on historical completion rates, 18,598.3 MW (17.3 percent) are expected to go into service. Based on historical completion rates and the ELCC derate factors using the class ratings for the 2026/2027 Base Residual Auction, the 107,595.6 MW of capacity requests currently under construction, suspended or active in the queue would be reduced to 5,610.6 MW of capacity (5.2 percent of the total requested capacity).
- As of March 31, 2025, 8,190 projects, representing 824,096.3 MW, have entered the queue process since its inception in 1998. Of those, 1,244 projects, representing 93,129.4 MW (11.3 percent of the MW), went into service. Of the projects that entered the queue process, 4,915 projects, representing 563,899.4 MW (68.4 percent of the MW) withdrew prior to completion. Such projects may create barriers to entry for projects that would otherwise be completed, by taking up queue positions, increasing interconnection costs and creating uncertainty.
- In the first three months of 2025, 994.8 MW from the queue went into service. Of the 994.8 MW that went in service, 994.8 MW (100.0 percent) were solar units.
- The number of queue entries increased during the past several years, primarily renewable projects. Of the 5,538 projects that entered the queue from January 1, 2015, through March 31, 2025, 4,111 projects (74.2 percent) were renewable. Of the 467 projects that entered the queue in 2023, 414 projects (88.7 percent) were renewable. Renewable projects make up 77.5 percent of all projects in the queue and account for 72.0 percent of the nameplate MW currently active, suspended or under construction in the queue as of March 31, 2025.
- On March 31, 2025, 37,335.2 MW, on an energy basis, were in generation request queues that had reached the construction service agreement milestone or equivalent, in the status of active, suspended or under construction. Of the 37,335.2 MW, 18,572.4 MW (49.7 percent) had not begun construction, 11,219.6 MW (30.0 percent) had begun construction, but are now suspended, and 7,563.2 MW (20.3 percent) are currently under construction. Reaching the final milestone required prior to construction does not mean a project will immediately begin construction or even that it necessarily will ever begin construction.

202 *ELCC Class Ratings for 2026/2027 Base Residual Auction*, PJM Interconnection L.L.C. (February 28, 2025) <https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/2026-27-bra-elcc-class-ratings.pdf>.
203 The 2026/2027 Base Residual Auction ELCC factors are used for the ELCC derate adjusted MW. The adjusted MW are calculated using the four hour storage ELCC derate for battery resources, tracking solar for solar resources and onshore wind for wind resources.
204 *ELCC Class Ratings for 2026/2027 Base Residual Auction*, PJM Interconnection L.L.C. (February 28, 2025) <https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/2026-27-bra-elcc-class-ratings.pdf>.
205 The 2026/2027 Base Residual Auction ELCC factors are used for the ELCC derate adjusted MW. The adjusted MW are calculated using the four hour storage ELCC derate for battery resources, tracking solar for solar resources and onshore wind for wind resources.
206 *ELCC Class Ratings for 2026/2027 Base Residual Auction*, PJM Interconnection L.L.C. (January 23, 2025) <https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/2026-27-bra-elcc-class-ratings.pdf>.
207 The 2026/2027 Base Residual Auction ELCC factors are used for the ELCC derate adjusted MW. The adjusted MW are calculated using the four hour storage ELCC derate for battery resources, tracking solar for solar resources and onshore wind for wind resources.

Regional Transmission Expansion Plan (RTEP)

Market Efficiency Process

- There are significant issues with PJM's benefit/cost analysis that should be addressed prior to approval of additional projects. If done correctly and if FTRs/ARRs returned 100 percent of congestion to load, the benefit/cost analysis would include the total net change in production costs and would not include congestion. In addition, PJM's benefit/cost analysis includes only the decreases in costs to load and ignores the increases in costs to load associated with market efficiency projects.
- Through March 31, 2025, PJM has completed five market efficiency cycles under Order No. 1000.[208] PJM delayed the opening of the 2022/2023 Long-Term Window until the reliability violations for the 2022 Window 3 were addressed. In January 2024, PJM completed updating the 2022/2023 market efficiency base case to include the solution selected from the 2022 Window 3. No flowgates experienced historical congestion that required an open window. PJM will continue to analyze the congestion patterns as part of the 2024/25 Market Efficiency cycle. In February 2024, PJM completed the 2024/2025 market efficiency base case. In May 2024, PJM posted the 2024/2025 Market Efficiency planning assumptions. PJM posted an updated 2024/2025 base case in July 2024, and requested stakeholder feedback by August 31, 2024. PJM is currently preparing the final base case, sensitivity scenarios and congestion drivers. The long term market efficiency window is expected to open on April 11, 2025 and close on June 10, 2025.

PJM MISO Interregional Market Efficiency Process (IMEP)

- PJM and MISO developed a process to facilitate the construction of interregional projects in response to the Commission's concerns about interregional coordination along the PJM-MISO seam. This process, called the Interregional Market Efficiency Process (IMEP), operates on a two year study schedule and is designed to address forward looking congestion.

  The simultaneous use for joint projects of an incorrectly defined benefit/cost method by PJM and the correct method by MISO results in an over allocation of the costs associated with joint PJM/MISO projects to PJM participants and in some cases approval of projects that do not pass a correctly defined benefit/cost test.

PJM MISO Targeted Market Efficiency Process (TMEP)

- PJM and MISO developed the Targeted Market Efficiency Process (TMEP) to facilitate the resolution of historic congestion issues that could be addressed through small, quick implementation projects.

PJM MISO Interregional Transfer Capability Study (ITCS)

- PJM and MISO developed the Interregional Transfer Capability Study (ITCS) to help identify potential transmission projects that could incrementally improve the systems' ability to mitigate constraints, improve market efficiency, respond to extreme weather and increase interregional transfer capability.

Supplemental Transmission Projects

- Supplemental projects are defined to be "transmission expansions or enhancements that are not required for compliance with PJM criteria and are not state public policy projects according to the PJM Operating Agreement. These projects are used as inputs to RTEP models, but are not required for reliability, economic efficiency or operational performance criteria, as determined by PJM."[209] Supplemental projects are exempt from competition.
- The average number of supplemental projects in each expected in service year increased by 1,155.0 percent, from 20 for years 1998 through 2007 (pre Order No. 890) to 251 for years 2008 through 2025 (post Order 890).[210]

208 See *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011) (Order No. 1000), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132 (2012).

209 See PJM. "Transmission Construction Status," (Accessed on March 31, 2025) <https://www.pjm.com/planning/m/project-construction>.

210 See *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 118 FERC ¶ 61,119, *order on reh'g*, Order No. 890-A, 121 FERC ¶ 61,297 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

End of Life Transmission Projects

- An end of life transmission project is a project submitted for the purpose of replacing existing infrastructure that is at, or is approaching, the end of its useful life. End of life transmission projects should be included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to require competition to build the project. Under the current approach, end of life projects are excluded from the RTEP process and exempt from competition.

Board Authorized Transmission Upgrades

- The Transmission Expansion Advisory Committee (TEAC) reviews proposals to improve transmission reliability in PJM and between PJM and neighboring regions. These proposals, which include reliability baseline, network, market efficiency and targeted market efficiency projects, as well as scope changes and project cancellations, but exclude supplemental and end of life projects, are periodically presented to the PJM Board of Managers for authorization.[211] In the first three months of 2025, the PJM Board approved $7.73 billion in upgrades. As of March 31, 2025, the PJM Board has approved $57.8 billion in system enhancements since 1999.

Transmission Competition

- The MMU makes several recommendations related to the competitive transmission planning process. The recommendations include improved process transparency, incorporation of competition between transmission and generation alternatives, and the removal of barriers to competition from nonincumbent transmission. These recommendations would help ensure that the process is an open and transparent process that results in the most competitive solutions.
- On May 24, 2018, the PJM Markets and Reliability Committee (MRC) approved a motion that required PJM, with input from the MMU, to develop a comparative framework to evaluate the quality and effectiveness of competitive transmission proposals with binding cost containment proposals compared to proposals from incumbent and nonincumbent transmission companies without cost containment provisions.

Qualifying Transmission Upgrades (QTU)

- A Qualifying Transmission Upgrade (QTU) is an upgrade to the transmission system, financed and built by market participants, that increases the Capacity Emergency Transfer Limit (CETL) into an LDA and can be offered into capacity auctions as capacity. Once a QTU is in service, the upgrade is eligible to continue to offer the approved incremental import capability into future RPM Auctions. As of March 31, 2025, no QTUs have cleared a Base Residual Auction or an Incremental Auction.

Transmission Facility Outages

- PJM maintains a list of reportable transmission facilities. When a reportable transmission facility needs to be taken out of service, PJM transmission owners are required to report planned transmission facility outages as early as possible. PJM processes the transmission facility outage requests according to rules in PJM's Manual 3 to decide if the outage is on time or late and whether or not they will allow the outage.[212]
- There were 15,975 transmission outage requests submitted in the first 10 months of the 2024/2025 planning period. Of the requested outages, 73.9 percent were planned for less than or equal to five days and 10.3 percent were planned for greater than 30 days. Of the requested outages, 41.3 percent were late according to the rules in PJM's Manual 3.

Section 12 Recommendations

Generation Retirements

- The MMU recommends that CIRs should end on the date of retirement in order to help ensure competitive markets and competitive access to the grid. The rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors or to exercise market

211 Supplemental Projects, including the end of life subset of supplemental projects, do not require PJM Board of Managers authorization.

212 See "PJM Manual 03: Transmission Operations," Rev. 67 (November 21, 2024).

power by requiring high payments for CIRs.[213] (Priority: Medium. First reported 2013. Status: Partially adopted, 2012.)

Generation Queue

- Given the significance of data to market participants and regulators, the MMU recommends that all queue data and supplemental, network and baseline project data, including projected in service dates and estimated and final costs, be regularly updated with accurate and verifiable data. PJM does not update this data. (Priority: High. First reported 2023. Not adopted.)
- The MMU recommends that barriers to entry be addressed in a timely manner in order to help ensure that the capacity market will result in the entry of new capacity to meet the needs of PJM market participants. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM establish an expedited PJM managed queue process to identify commercially viable projects that could help eliminate or reduce the need for specific RMRs or that could address specific reliability needs and allow the identified projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming. (Priority: High. First reported Q2, 2024. Status: Not adopted.)
- The MMU recommends improvements in queue management including that PJM establish a review process to ensure that projects are removed from the queue if they are not viable, as well as an expedited process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming.[214] (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends continuing analysis of the study phase of PJM's transmission planning to reduce the need for postponements of study results, to decrease study completion times, and to improve the likelihood that a project at a given phase in the study process will successfully go into service.[215] (Priority: Medium. First reported 2014. Status: Partially adopted.)
- The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest. Currently, these studies are performed by incumbent transmission owners under PJM's direction. This creates potential conflicts of interest, particularly when transmission owners are vertically integrated and the owner of transmission also owns generation. (Priority: Low. First reported 2013. Status: Not adopted.)

Market Efficiency Process

- The MMU recommends that the market efficiency process be eliminated because it is not consistent with a competitive market design. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that, if the market efficiency process is retained, PJM modify the rules governing benefit/cost analysis, the evaluation process for selecting among competing market efficiency projects and cost allocation for economic projects in order to ensure that all changes in production costs but not congestion costs, including increased costs to load and the risk of project cost increases, in all zones are included in order to ensure that the correct metrics are used for defining benefits. The MMU also recommends that, if the market efficiency process is retained, market efficiency projects that fail to meet PJM benefit/cost criteria in a Schedule 6 annual reevaluation, prior to construction commencing or prior to state approval, be canceled and removed from further consideration. (Priority: Medium. First reported 2018. Status: Not adopted.)

Comparative Cost Framework

- The MMU recommends that PJM modify the project proposal templates to include data necessary to perform a detailed project lifetime financial analysis. The required data includes, but is not limited to: capital expenditure; capital structure; return on equity; cost of debt; tax assumptions; ongoing capital expenditures; ongoing maintenance; and expected life. (Priority: Medium. First reported 2020. Status: Not adopted.)

213 See Comments of the Independent Market Monitor for PJM, Docket No. ER12-1177-000 (March 12, 2012) <http://www.monitoringanalytics.com/Filings/2012/IMM_Comments_ER12-1177-000_20120312.PDF>.
214 PJM Filing, FERC Docket No. ER22-2110-000 (June 14, 2022); 181 FERC ¶ 61,162 (2022).
215 Ibid.

Transmission Competition

- The MMU recommends, to increase the role of competition, that the exemption of supplemental projects from the Order No. 1000 competitive process be terminated and that the basis for all such exemptions be reviewed and modified to ensure that the supplemental project designation is not used to exempt transmission projects from a transparent, robust and clearly defined mechanism to require competition to build such projects or to effectively replace the RTEP process. (Priority: Medium. First reported 2017. Status: Not adopted. Rejected by FERC.)[216]
- The MMU recommends, to increase the role of competition, that the exemption of end of life projects from the Order No. 1000 competitive process be terminated and that end of life transmission projects be included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to require competition to build such projects. (Priority: Medium. First reported 2019. Status: Not adopted. Rejected by FERC.)[217]
- The MMU recommends that PJM enhance the transparency and queue management process for nonincumbent transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from nonincumbent transmission providers. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM incorporate the principle that the goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible. (Priority: Low. First reported 2001. Status: Not adopted.)
- The MMU recommends the creation of a mechanism to permit a direct comparison, or competition, between transmission and generation alternatives, including which alternative is less costly and who bears the risks associated with each alternative. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM establish fair terms of access to rights of way and property, such as at substations, in order to remove any barriers to entry and require competition between incumbent transmission providers and nonincumbent transmission providers in the RTEP. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that rules be implemented to require competition to provide financing for transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that storage resources not be includable as transmission assets for any reason. (Priority: High. First reported 2020. Status: Not adopted.)

Cost Allocation

- The MMU recommends a comprehensive review of the ways in which the solution based dfax allocation method is implemented. The goal for such a process would be to ensure that the most rational and efficient approach to implementing the solution based dfax method is used in PJM. Such an approach should allocate costs consistent with benefits and appropriately calibrate the incentives for investment in new transmission capability. No replacement approach should be approved until all potential alternatives, including the status quo, are thoroughly reviewed. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends changing the minimum distribution factor in the allocation from 0.01 to 0.00 and adding a threshold minimum usage impact on the transmission facilities.[218] (Priority: Medium. First reported 2015. Status: Not adopted.)

216 The FERC accepted tariff provisions that exclude supplemental projects from competition in the RTEP. 162 FERC ¶ 61,129 (2018), *reh'g denied*, 164 FERC ¶ 61,217 (2018).

217 In recent decisions addressing competing proposals on end of life projects, the Commission accepted a transmission owner proposal excluding end of life projects from competition in the RTEP process, 172 FERC ¶ 61,136 (2020), *reh'g denied*, 173 FERC ¶ 61,225 (2020), *affirmed*, American Municipal Power, Inc., et al. v. FERC, Case No. 20-1449 (D.C. Cir. November 17, 2023), and rejected a proposal from PJM stakeholders that would have included end of life projects in competition in the RTEP process, 173 FERC ¶ 61,242 (2020).

218 See *2015 State of the Market Report for PJM*, Volume 2, Section 12: Generation and Transmission Planning, at 463, Cost Allocation Issues.

Transmission Line Ratings

- The MMU recommends that all PJM transmission owners use the same methods to define line ratings and that all PJM transmission owners implement dynamic line ratings (DLR), subject to NERC standards and guidelines, subject to review by NERC, PJM and the MMU, and approval by FERC. (Priority: Medium. First reported 2019. Status: Partially adopted.)
- The MMU recommends that all PJM transmission owners investigate the applicability and potential cost savings of Grid Enhancing Technology (GET) and that all PJM transmission owners implement cost effective GET, subject to NERC standards and guidelines, subject to review by NERC, PJM and the MMU, and approval by FERC. (Priority: Medium. First reported Q2, 2024. Status: Not adopted.)
- The MMU recommends that the implementation of Grid Enhancing Technology (GET) be opened to competition from third parties, subject to NERC standards and guidelines, subject to review by NERC, PJM and the MMU, and approval by FERC. (Priority: Medium. First reported Q3, 2024. Status: Not adopted.)

Transmission Facility Outages

- The MMU recommends that PJM reevaluate all transmission outage tickets as on time or late as if they were new requests when an outage is rescheduled, create options for late requests based on the reasons, and apply the modified rules for late submissions to any such outages. The MMU recommends that PJM create options for treatment of late outages. The current rules apply more stringent rules, based on controlling actions, to late outages without distinguishing among reasons for late outages. (Priority: Low. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM draft a definition of the economic and physical congestion analysis required for transmission outage requests and associated triggers, including both the extent of overloaded facilities and the level of economic congestion, to include in PJM manuals after appropriate review with appropriate rules for on time and late outage requests. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM create options for late requests based on the reasons, and modify the rules to reduce or eliminate the approval of late outage requests submitted or rescheduled after the FTR auction bidding opening date, based on those options. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not permit transmission owners to divide long duration outages into smaller segments to avoid complying with the requirements for long duration outages. (Priority: Low. First reported 2015. Status: Not adopted.)

Section 12 Conclusion

The goal of the PJM market design should be to enhance competition and to ensure that competition is the core element of all PJM markets. Transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities has significant impacts on the energy and capacity markets. When generating units retire or load increases, there is no market mechanism in place that would require or even permit direct competition between transmission and generation to meet loads in the affected area. In addition, despite FERC Order No. 1000, there is not yet a transparent, robust and clearly defined mechanism to require competition to build transmission projects, to ensure that competitors provide a total project cost cap, or to obtain least cost financing through the capital markets.

The MMU recognizes that the Commission has issued orders that are inconsistent with the recommendations of the MMU and that PJM cannot unilaterally modify those directives. It remains the recommendation of the MMU that the PJM rules for competitive transmission development through the RTEP should build upon FERC Order No. 1000 to create real competition between incumbent transmission providers and nonincumbent transmission providers. The ability of transmission owners to block competition for supplemental projects and end of life projects and the reasons for that policy should be reevaluated. PJM should enhance the transparency and queue management process for nonincumbent transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from nonincumbent transmission.

Order No. 1000 removed the right of first refusal (ROFR) for transmission projects for incumbent transmission owners except for the case of supplemental projects. This created an incentive for incumbent transmission owners to designate projects as supplemental projects to avoid the Order No. 1000 competitive provisions. Two PJM states, Indiana and Michigan, have passed laws that provide ROFR to incumbent utilities/transmission owners.[219] [220]

Given the significant impact of transmission line ratings on all aspects of wholesale power markets, ensuring and improving the accuracy and transparency of line ratings is essential. Line ratings should incorporate ambient temperature conditions, wind speed and other relevant operating conditions. PJM real-time prices are calculated every five minutes for thousands of nodes. PJM prices are extremely sensitive to transmission line ratings. For consistency with the dynamic nature of wholesale power markets, line ratings should be updated in real time to reflect real time conditions and to help ensure that real-time prices are based on actual current line ratings. New technologies that permit dynamic line ratings (DLR) should be implemented. All PJM Transmission Owners should be required to immediately adopt current dynamic line rating (DLR) methods for all transmission facilities, subject to NERC standards and guidelines, subject to review by NERC, PJM and the MMU, and approval by FERC.

Given the slow pace of adoption by Transmission Owners of Grid Enhancing Technologies (GETs), PJM and the Commission should introduce rules that would allow third parties to propose adding GETs to the transmission system, subject to NERC standards and guidelines, subject to review by NERC, PJM and the MMU, and approval by FERC. The third parties would be compensated in the same way that TOs would be compensated for comparable investments.

Another element of opening competition would be to consider transmission owners' ownership of property and rights of way at or around transmission substations. In many cases, the land acquired included property intended to support future expansion of the grid. Incumbents have included the costs of the property in their rate base, paid for by customers. PJM now has the responsibility for planning the development of the grid under its RTEP process. Property bought to facilitate future expansion should be a part of the RTEP process and be made available to all providers on equal terms.

The process for determining the reasonableness or purpose of supplemental transmission projects that are asserted to be not needed for reliability, economic efficiency or operational performance as defined under the RTEP process needs additional oversight and transparency. If there is a need for a supplemental project, that need should be clearly defined and there should be a transparent, robust and clearly defined mechanism to require competition to build the project. If there is no defined need for a supplemental project for reliability, economic efficiency or operational performance then the project should not be included in rates.

Managing the generation queues is a complex process. The PJM queue evaluation process will be significantly improved, based on the proposal submitted by PJM on June 14, 2022, and approved by FERC on November 29, 2022.[221] [222] The new rules include significant modifications to the interconnection process designed to address some of the key underlying issues and significantly improve the efficiency of the process. These modifications include process efficiency enhancements, recognition of project clusters affecting the same transmission facilities, incentives to reduce the entry of speculative projects in the queue, and incentives to remove projects that are not expected to reach commercial operation. The new process should help to reduce backlog and to remove projects that are not viable earlier to help improve the overall efficiency of the queue process.

While the changes in the queue process will clearly improve the process, the MMU's recommendations related to the queue process will remain until the new process is in place and it can be evaluated. The impact of the modifications to the queue process will need to be evaluated to determine if they successfully remove projects from the queue if they are not viable, and

219 See IN Code § 8-1-38-9, effective 7/1/2023. Applies to transmission facilities approved for construction through an RTO planning process. Incumbent Transmission Owner must exercise within 90 days.

220 See MCL §460.593, effective 12/17/2021. Applies to regionally cost shared transmission lines included in a plan adopted by a recognized planning authority. Must be exercised by the incumbent (s) within 90 days after plan is adopted/approved.

221 See *PJM*, Docket No. ER22-2110 (June 14, 2022).

222 See 181 FERC ¶ 61,162 (2022).

allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress. The behavior of project developers also creates issues with queue management. When developers put multiple projects in the queue to maintain their own optionality while planning to build only one they also affect all the projects that follow them in the queue. Project developers may also enter speculative projects in the queue and then put the project in suspended status while they address financing. The impacts of such behavior and the incentives for such behavior are addressed in the new process which includes nonrefundable fees, credit requirements, enhanced site control, elimination of the ability to suspend a project and milestone requirements. The impact of these aspects of the revised interconnection process should continue to be evaluated to ensure that they are having the desired effect on project developer behavior. The PJM queue evaluation process should continue to be improved to help ensure that barriers to competition for new generation investments are not created. Issues that need to be addressed include the ownership rights to CIRs and whether transmission owners should perform interconnection studies.

The roles and efficiency of PJM, TOs and developers in the queue process all need to be examined and enhanced in order to help ensure that the queue process can function effectively and efficiently as the gateway to competition in the energy and capacity markets and not as a barrier to competition.

The Commission should require PJM, for example, to enhance the transparency and queue management process for nonincumbent transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from nonincumbent transmission.

On January 31, 2025, PJM submitted revisions to the PJM Tariff to expedite the transfer of CIRs from deactivating generating resources to new replacement resources.[223] The suggestion that generation owners should be permitted to avoid the queue process and directly transfer the generation CIRs to an affiliate or directly sell the CIRs to an unaffiliated entity should be rejected.[224] [225] This proposed approach is about creating a process to maximize the value of existing CIRs to incumbent generators and not about facilitating the efficient replacement of retiring resources. In effect, this approach, if adopted by the large number of retiring units, would create a chaotic, bilateral private queue process that would create market power and facilitate the exercise of market power in the sale of CIRs by incumbent generators. In effect the proposed approach would replace a significant part of the recently redesigned PJM queue process. The proposed continuation of retention of CIRs by incumbent generators creates the potential for delays of up to a year and the proponents have proposed the option to request further delays. This approach would inappropriately delegate the authority from PJM to the incumbent generator to choose the new resource based on highest offer for CIRs rather than based on PJM defined system reliability needs. There would be no requirement to even be a capacity resource and there would be no requirement to offer the capacity into the capacity market. After the entire process, the contribution to PJM reliability could be zero. PJM's recently proposed expedited process for addressing reliability needs (RRI) is preferable and should be considered as the preferred alternative to the proposed approach from the Planning Committee stakeholder process.

The MMU recommends that PJM establish an expedited PJM managed queue process to identify commercially viable projects that could help eliminate or reduce the need for specific RMRs or that could address specific reliability needs and allow the identified projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming. Rules should be developed to permit PJM to advance projects in the queue if they would resolve immediate reliability issues that result, for example, from unit retirements. The rules should be consistent with the flexibility included in the new queue process but add the option for PJM to expedite the interconnection and commercial operation of projects in the queue that

223 See PJM Interconnection, L.L.C., Docket No. ER25-1128 (January 31, 2025).

224 See PJM. "*Enhancing Capacity Interconnection Rights (CIR) Transfer Efficiency: Problem / Opportunity Statement*," <https://www.pjm.com/-/media/committees-groups/subcommittees/ips/2023/20230731/20230731-item-08b---enhancing-capacity-interconnection-rights---cir---transfer-efficiency-problem-statement.ashx>.

225 On April 30, 2024, the CIR Transfer Efficiency issue was transferred from the Interconnection Process Subcommittee (IPS) to the Planning Committee (PC).

would address identified reliability issues, consistent with the standing of the projects in the queue.

The PJM queue process should continue to define available and needed CIRs for all capacity queue projects. CIRs from retiring units should be made available to the next resource in the queue that can use them, on the retirement date of the retiring resource. Generation owners do not have property rights in CIRs. The value of CIRs is a result of the entire transmission system which has been paid for by customers and other generators. The value of CIRs is a result of the existence of a network and is not a result solely or even primarily of the investment that may or may not have been required in order to get CIRs. The cost of CIRs is part of project costs included in generation owners' investment decisions like any other project cost and subject to the same risk and reward structure. Open access to the transmission system by new resources should not be limited by claims to own the access rights by retiring units. In addition, the proposal to bypass the PJM interconnection process with a private, bilateral process ignores the fact that if the new resource is a renewable resource or a storage resource, the new resource does not have a capacity market must offer requirement. The PJM interconnection process could be bypassed, CIRs transferred and then the resource does not offer into the capacity market. In that case, scarce CIRs will be withheld by a generator who does not provide capacity and customers have to pay for an additional capacity resource instead.

The fundamental purpose of the queue process is to provide open access to the grid for supply resources. More specifically, the fundamental purpose of the queue process for capacity resources is to provide open access to the grid and to ensure that the energy from capacity resources is deliverable so that capacity resources can meet their must offer obligations in the energy market and provide reliable energy supply during all conditions. In order to ensure that open access, all capacity resources should be required to have a must offer obligation in the capacity market. If they do not, such resources are effectively withholding access to the grid from capacity resources that would take on a must offer obligation in the capacity market. The result creates market power for the resources with no must offer obligation, noncompetitively limits access to the grid, increases capacity market prices above the competitive level, and creates uncertainty and unpredictable volatility in the capacity market.

The addition of a planned transmission project changes the parameters of the capacity auction for the area, changes the amount of capacity needed in the area, changes the capacity market supply and demand fundamentals in the area and may effectively forestall the ability of generation to compete. But there is no mechanism to permit a direct comparison, let alone competition, between transmission and generation alternatives. There is no mechanism to evaluate whether the generation or transmission alternative is less costly, whether there is more risk associated with the generation or transmission alternatives, or who bears the risks associated with each alternative. Creating such a mechanism should be an explicit goal of PJM market design.

The current market efficiency process does exactly the opposite by permitting transmission projects to be approved without competition from generation. The broader issue is that the market efficiency project approach explicitly allows transmission projects to compete against future generation projects, but without allowing the generation projects to compete. Projecting speculative transmission related benefits for 15 years based on the existing generation fleet and existing patterns of congestion eliminates the potential for new generation to respond to market signals. The market efficiency process allows assets built under the cost of service regulatory paradigm to displace generation assets built under the competitive market paradigm. In addition, there are significant issues with PJM's current benefit/cost analysis which cause it to consistently overstate the potential benefits of market efficiency projects. The market efficiency process is misnamed. The MMU recommends that the market efficiency process be eliminated.

In addition, the use of an incorrectly defined cost-benefit method by PJM and the correct method by MISO results in an over allocation of the costs associated with joint PJM/MISO transmission projects to PJM participants and in some cases approval of projects that do not pass a correctly defined benefit/cost test.

If it is retained, there are significant issues with PJM's benefit/cost analysis that should be addressed prior to approval of additional projects. The current benefit/cost analysis explicitly and incorrectly ignores the increased costs to load in zones that results from an RTEP project when calculating the energy market benefits. All increases and decreases in costs should be included in all zones and LDAs. The definition of benefits should also be reevaluated.

The benefit/cost analysis should also account for the fact that the transmission project costs are not subject to cost caps and may exceed the estimated costs by a wide margin. When actual costs exceed estimated costs, the benefit/cost analysis is effectively meaningless and low estimated costs may result in inappropriately favoring transmission projects over market generation projects. The risk of cost increases for transmission projects should be incorporated in the benefit/cost analysis.

There are currently no market incentives for transmission owners to plan, submit and complete transmission outages in a timely and efficient manner. Requiring transmission owners to pay does not create an effective incentive when those payments are passed through to transmission customers. The process for the submission of planned transmission outages needs to be carefully reviewed and redesigned to limit the ability of transmission owners to submit transmission outages that are late for FTR auction bid submission dates and are late for the day-ahead energy market and that have large and unnecessary impacts on the PJM energy market. The submission of late transmission outages can inappropriately affect market outcomes when market participants do not have the ability to modify market bids and offers. The PJM process for evaluating the congestion impact of transmission outages needs to be clearly defined and upgraded to provide for management of transmission outages to minimize market impacts. The MMU continues to recommend that PJM draft a clear and expanded definition of the congestion analysis required for transmission outage requests that is incorporated in the PJM Market Rules. PJM Manual 38 currently defines congestion resulting from a transmission outage as an overload on transmission facilities rather than using the general economic definition of congestion resulting from out of merit generation to control constraints. PJM does not currently evaluate the economic impact of congestion when reviewing proposed transmission outages.[226]

The treatment by PJM and Dominion Virginia Power of the outage for the Lanexa – Dunnsville Line illustrates some of the issues with the current process. The outage was submitted and delayed more than once. PJM's analysis of expected congestion did not highlight the magnitude of the issue. Dominion Virginia Power did not stage the outage so as to minimize market disruption and congestion until after there were significant disruptions and congestion.

As an example of the complexities of defining the benefits of transmission investments, the reduction in congestion is frequently and incorrectly cited as a metric of benefits. Congestion is frequently misunderstood. Congestion is not static. Congestion exhibits dynamic intertemporal variability and dynamic locational variability. More importantly, congestion is not the correct metric for evaluating the potential benefits of enhancing the transmission grid. The correct metric is the total net change in production costs.

There is not a secular trend towards increasing congestion in PJM. Congestion is volatile on a monthly basis. Congestion is also volatile on an hourly and daily basis. For example, higher congestion can result from changes in seasonal and daily/hourly fuel costs.

The level and distribution of congestion at a point in time is a function of the location and size of generating units, the relative costs of the fuels burned and the associated marginal costs of generating units, the location and size of load and the locational capability of the transmission grid. Each of these factors changes over time.

The geographic distribution of congestion is dynamic. The nature and location of congestion in the PJM system has changed significantly over the last 10 years and continues to change. The nature and location of congestion in PJM can also change from one day to the next as a result of changes in relative fuel costs. As a result, building transmission to address a specific pattern of congestion does not make sense, unless the technology can be easily moved to new locations as conditions change. The transmission system is only one

226 PJM, "Manual 38: Operations Planning," Rev. 19 (January 23, 2025) at 19-20.

of many reasons that congestion exists. The dynamic nature of congestion and the multiple, interactive causes of congestion make it virtually impossible to identify the standalone impacts of an individual transmission investment on future congestion. It is possible, for example, that congestion occurring during a period of a few days in the winter as a result of very high fuel prices, significantly increases the reported level of congestion for the entire year. This has occurred in PJM. It would be a mistake to consider that level of congestion to be a signal to build transmission.

At a more fundamental level, congestion is not the correct metric for evaluating the potential benefits of enhancing the transmission grid. When there are binding transmission constraints and locational price differences, load pays more for energy than generation is paid to produce that energy. The difference is congestion. Congestion is neither good nor bad, but is a direct measure of the extent to which there are multiple marginal generating units with different offers dispatched to serve load as a result of transmission constraints. Congestion occurs when available, least-cost energy cannot be delivered to all load because transmission facilities are not adequate to deliver that energy to one or more areas, and higher cost units in the constrained area(s) must be dispatched to meet the load. The result is that the price of energy in the constrained area(s) is higher than in the unconstrained area. Load in the constrained area pays the higher price for all energy including energy from low cost generation and energy from high cost generation, while only high cost generators are paid the high price at their bus and low cost generators are paid only the low price at their bus.

If FTRs worked perfectly and were assigned directly to load, FTRs would return all congestion to the load that paid the congestion. Congestion is not a cost, it is an accounting result of a market based on locational energy prices in which all load in a constrained area pays the higher single market clearing locational price, resulting in excess payments by load that are not paid to generation, which should be returned to load.

Counterintuitively, congestion actually increases when the transmission capacity between areas with lower cost generation and areas with higher cost generation increases but does not fully eliminate the need for some higher cost local generation. The smaller the amount of higher cost local generation needed to meet load, the more of the local load is met via low cost generation delivered over the transmission system and therefore the higher is the difference between what load pays and generation receives, congestion.

For all these reasons, if done correctly and if FTRs/ARRs returned 100 percent of congestion to load, the benefit/cost analysis for transmission projects would include the total net change in production costs and would not include congestion. The change in production costs correctly measures the changes in cost to load that result from a project.

The PJM Regional Transmission Expansion Plan (RTEP) successfully addresses the need for transmission investment to reliably meet load. Together with the requirement that new generation pay interconnection costs, the RTEP process has resulted in the appropriate level of new transmission investment in PJM. There is no evidence that the PJM planning process is not adequate to meet the requirements of the PJM markets. Additional transmission investment is not a panacea. Transmission investment is expensive and long lived and it is essential that transmission investments be carefully planned for clearly identified needs in order to ensure that power markets can continue to provide reliable service at a competitive price.

PJM must make out of market payments to units that want to retire (deactivate) but that PJM requires to remain in service, for limited operation, for a defined period because the unit is needed for reliability.[227] This provision has been known as Reliability Must Run (RMR) service but RMR is not defined in the PJM tariff. The correct term is Part V reliability service. The need to retain uneconomic units in service reflects a flawed market design and/or planning process problems. If a unit is needed for reliability, the market should reflect a locational value consistent with that need which would result in the unit remaining in service or being replaced by a competitor unit. The planning process should evaluate the impact of the loss of units at risk and determine in advance whether transmission upgrades are required in order to limit the duration of Part V service for individual units. It is essential that the deactivation provisions of the tariff be evaluated and modified. It

227 OATT Part V §114.

is also essential that PJM look forward and attempt to plan for foreseeable unit retirements, whether for economic or regulatory reasons. PJM should consider an expedited queue process for projects that could replace the retiring capacity including the immediate transfer of the retiring unit's CIRs to units in the queue in order to permit generation to compete as an alternative to the current transmission only approach.

An area in northern Virginia in the Dominion Transmission Zone, known as Data Center Alley, has experienced significant load growth from data centers. Dominion has presented 44 supplemental project requests to serve the increase in load through the summer of 2025. As part of the supplemental planning process, PJM performs a do no harm analysis. PJM identified the need for additional baseline reinforcements to support the load growth. These baseline reinforcements were addressed in the 2022 RTEP Window 3, when the PJM board approved $1.4 billion of necessary baseline upgrades specific to the Data Center Alley reinforcements.[228] These regional transmission costs were allocated according to Schedule 12 of PJM's Open Access Transmission Tariff (OATT), where costs are shared across all zones by a combination of load ratio share and distribution factor impacts. The transmission owners include these project costs in their base case, and all retail customers in the PJM footprint pay for those upgrade costs through increased energy bills. The cost allocation of the $1.4 billion in baseline upgrades are assigned to all retail customers and not solely to the customers requesting interconnection.

The high level of customer requests in Data Center Alley resulted in the need for significant baseline reliability upgrades. These costs were allocated per Schedule 12 of the PJM OATT. Not all customer requests result in reliability upgrades. Transmission upgrades for customer requests that are submitted through the supplemental planning process are allocated 100 percent to the zone where they are interconnecting. The transmission owner of that zone then includes those project costs in their rate base, and all retail customers in that zone pay those costs.

228 See "*Transmission Expansion Advisory Committee (TEAC) Recommendations to the PJM Board*," December 2023. <https://www.pjm.com/-/media/committees-groups/committees/teac/2023/20231205/20231205-pjm-teac-board-whitepaper-december-2023.ashx>.

The main focus of PJM's planning requirements has been to ensure adequate transmission to allow for generation to reliably serve load. Historically, PJM has had enough excess generation to serve the forecasted load in the RTEP process. In recent years, due in part to the significant increase in load resulting from large load interconnection requests and an increase in thermal unit deactivations, meeting forecasted loads and reserves with existing generation has become an issue. In order to solve the RTEP study cases, PJM must make assumptions about the existing and future generation to include in the RTEP model based on the need to serve load. The RTEP analysis first includes all existing generation that is expected to remain in service for the year being studied. When the forecasted load exceeds the expected in service generation, the RTEP analysis includes future generation. Planned generators with a signed interconnection service agreement (ISA) or generation interconnection agreement (GIA), or that cleared a BRA, are included. When the PJM load in the RTEP analysis exceeds the sum of existing generation and generation with an executed final agreement, the RTEP analysis adds speculative new generation that is in its Phase 3 system impact study status to meet the load. If needed, additional generation (pre-GIA stage or with a suspended status) may be modeled consistent with the procedures noted in Manual 14B.[229] [230] The RTEP analysis is not adequately coordinated with PJM markets analysis including the energy and capacity markets.

229 See "Review of 2025 RTEP Assumptions," presented at the January 7, 2025 meeting of the Transmission Expansion Advisory Committee. <https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2025/20250107/20250107-item-11---2025-rtep-assumption.pdf>.

230 See "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 57 (September 25, 2024).

Overview: Section 13, FTRs and ARRs

Auction Revenue Rights

Market Structure

- **ARR Ownership.** In the 2024/2025 planning period ARRs were allocated to 1,523 individual participants, held by 126 parent companies, up from 1,504 individual parents, held by 123 parent companies in the 2023/2024 planning period. ARR ownership for the 2024/2025 planning period was unconcentrated with an HHI of 610, down from 617 for the 2023/2024 planning period.

Market Behavior

- **Self Scheduled FTRs.** For the 2024/2025 planning period, 25.3 percent of eligible ARRs were self scheduled as FTRs, up from 24.1 percent for the 2023/2024 planning period.

Market Performance

- **ARRs as an Offset to Congestion.** ARRs have not served as an effective mechanism to return all congestion revenues to load. For the first ten months of the 2024/2025 planning period, ARRs and self scheduled FTRs offset only 51.3 percent of total congestion. Congestion payments by load in some zones were more than offset and congestion payments in some zones were less than offset. Load has been underpaid congestion revenues by $4.8 billion from the 2011/2012 planning period through the first ten months of the 2024/2025 planning period. The cumulative offset for that period was only 68.7 percent of total congestion.
- **ARR Payments.** For the first ten months of the 2024/2025 planning period, the ARR target allocations, which are based on the nodal price differences from the Annual FTR Auction, were $1,443.9 million, while PJM collected $1,661.8 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions. For the 2023/2024 planning period, the ARR target allocations were $1,592.2 million while PJM collected $1,874.5 million from the combined Annual and Monthly Balance of Planning Period FTR Auctions.
- **ARR.** For the first ten months of the 2024/2025 planning period there was not enough day-ahead congestion and FTR auction revenue to pay FTR target allocations. As a result, all $159.6 million of FTR auction revenue over ARR target allocations was transferred from ARR holders (load) to FTR holders. Although PJM refers to this as a surplus, there is no such thing as surplus FTR auction revenue based on market logic. FTR Auction revenue results from the market prices paid by willing FTR buyers, should be paid to ARR holders, and should not be returned to FTR buyers for any reason.
- **Residual ARRs.** Residual ARRs are only available on contract paths prorated in Stage 1 of the annual ARR allocation, are only effective for single, whole months and cannot be self scheduled. Residual ARR clearing prices are based on monthly FTR auction clearing prices. Residual ARRs with negative target allocations are not allocated to participants. Instead they are removed and the model is rerun.

  In the first ten months of the 2024/2025 planning period, PJM allocated a total of 27,611.0 MW of residual ARRs with a total target allocation of $21.5 million, up from 21,249.5 MW, with a total target allocation of $7.2 million, in the same period of the 2023/2024 planning period.
- **ARR Reassignment for Retail Load Switching.** There were 31,951 MW of ARRs associated with $0.7 million of revenue that were reassigned for the first ten months of the 2024/2025 planning period. There were 34,601 MW of ARRs associated with $0.8 million of revenue that were reassigned in the 2023/2024 planning period.

Financial Transmission Rights

Market Design

- **Monthly Balance of Planning Period FTR Auctions.** The design of the Monthly Balance of Planning Period FTR Auctions includes auctions for each remaining month in the planning period.

Market Structure

- **Patterns of Ownership.**[231] For the Monthly Balance of Planning Period Auctions, financial entities purchased 95.7 of all prevailing and counter flow FTRs, including 94.8 percent of prevailing flow and 96.8 percent of counter flow FTRs for the first ten months of the 2024/2025 planning period. Financial entities owned 87.9 percent of all prevailing and counter flow FTRs, including 82.3 percent of all prevailing flow FTRs and 94.6 percent of all counter flow FTRs during the first ten months of the 2024/2025 planning period. Self scheduled FTRs account for 4.2 percent of all FTRs held.

- **Market Concentration.** In the Monthly Balance of Planning Period Auctions for the first ten months of the 2024/2025 planning period, ownership of cleared prevailing flow bids was unconcentrated in all periods. Ownership of cleared counter flow bids was unconcentrated in 90.7 percent of periods and moderately concentrated in 9.3 percent of periods.

Market Behavior

- **Sell Offers.** In a given auction, market participants can sell FTRs acquired in preceding auctions or preceding rounds of auctions. In the 2024/2027 Long Term FTR Auction, total participant FTR sell offers were 1,293,978 MW. In the 2024/2025 Annual FTR Auction, total participant FTR sell offers were 1,172,749 MW. In the Monthly Balance of Planning Period FTR Auctions for the first ten months of the 2024/2025 planning period, total participant FTR sell offers were 43,982,369 MW.

- **Buy Bids.** In the 2024/2027 Long Term FTR auction, total FTR buy bids were 5,729,618 MW, up 312.7 percent from 1,388,159 MW the previous long term auction. There were 4,770,381 MW of buy and self scheduled bids in the 2024/2025 Annual FTR Auction, up 26.4 percent from 3,773,919 MW the previous planning period. The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first ten months of the 2024/2025 planning period were 61,554,629 MW.

- **FTR Forfeitures.** Total FTR forfeitures were $3.1 million for the first ten months of the 2024/2025 planning period, up 47.8 percent from $2.1 million for the first ten months of the 2023/2024 planning period.

- **Credit.** There were no collateral defaults and no payment defaults in the first three months of 2025.

Market Performance

- **Quantity.** In the 2024/2027 Long Term FTR Auction 638,671 MW (11.1 percent) of buy bids cleared and 139,507 MW (10.8 percent) of sell offers cleared. In the Annual FTR Auction for the 2024/2025 planning period 1,028,420 MW (21.6 percent) of buy and self scheduled bids cleared, up 17.1 percent from 878,232 (23.3 percent) for the previous planning period. In the first ten months of the 2024/2025 planning period, Monthly Balance of Planning Period FTR Auctions cleared 9,599,888 MW (20.2 percent) of FTR buy bids and 5,322,408 MW (13.7 percent) of FTR sell offers. For the 2023/2024 planning period, Monthly Balance of Planning Period FTR Auctions cleared 9,710,278 MW (14.5 percent) of FTR buy bids and 5,894,197 MW (16.2 percent) of FTR sell offers.

- **Price.** The weighted average buy bid FTR price in the 2024/2027 Long Term FTR Auction was $0.07 per MW, down from $0.13 from the 2023/2026 Long Term FTR Auction. The weighted average buy bid FTR price in the Annual FTR Auction for the 2024/2025 planning period was $0.30 per MW, down from $0.33 per MW in the 2023/2024 planning period. The weighted average buy bid cleared FTR price in the Monthly Balance of Planning Period FTR Auctions for all periods in the first ten months of the 2024/2025 planning period was $0.43 per MWh, down from $0.48 in the 2023/2024 planning period.

- **Revenue.** The 2024/2027 Long Term FTR Auction generated $102.6 million of net revenue for all FTRs, down 44.4 percent from $184.5 million from the 2023/2026 Long Term FTR Auction. The 2024/2025 Annual FTR Auction generated $1,475.2 million in net revenue, down 12.9 percent from $1,694.3 million for the 2023/2024 Annual FTR Auction. The Monthly Balance of Planning Period FTR Auctions resulted in net revenue of $76.5 million in the first ten months of the 2024/2025

231 Beginning in the *2025 Quarterly State of the Market Report for PJM: January through March*, the MMU categorizes all participants owning FTRs in PJM as either physical or financial at an account level. In prior reports, participants were categorized as either physical or financial at an organization level.

planning period, down 4.7 percent from $80.2 million in the first ten months of the 2023/2024 planning period.

- **"Revenue Adequacy."** For the first ten months of the 2024/2025 planning period there was not enough day-ahead congestion revenue to pay FTR target allocations. As a result, $159.6 million of FTR auction revenue was transferred from ARR holders (load) to FTR holders, and FTRs were paid 98.8 percent of the target allocations for the first ten months of the 2024/2025 planning period. Based on market logic, there is no such thing as surplus FTR auction revenue and there is no such thing as revenue inadequacy. FTR Auction revenue results from the market prices paid by willing FTR buyers, should be paid to ARR holders, and should not be returned to FTR buyers for any reason.
- **Profitability.** FTR profitability is the difference between the revenue received directly from holding an FTR plus any revenue from the sale of an FTR, and the cost of buying the FTR. In the first 10 months of the 2024/2025 planning period, profits for all participants were $798.3 million, up from $193.4 million in profits in the same time period in the 2023/2024 planning period. In the first 10 months of the 2024/2025 planning period, physical entities received $54.3 million in profits on FTRs purchased directly (not self scheduled), up from $21.6 million profits in the first 10 months of the 2023/2024 planning period. Financial entities received $744.0 million in profits, 93.2 percent of total profits, up from $171.8 million profits in the same time period in the 2023/2024 planning period.

Section 13 Recommendations

Market Design

- The MMU recommends that the current ARR/FTR design be replaced with defined congestion revenue rights (CRRs). A CRR is the right to actual congestion revenue that is paid by physical load at a specific bus, zone or aggregate. (Priority: High. First reported 2015. Status: Not adopted.)

ARR

- The MMU recommends that the ARR/FTR design be modified to ensure that the rights to all congestion revenues are assigned to load. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that all historical generation to load paths be eliminated as a basis for assigning ARRs. The MMU recommends that the current design be replaced with a design in which the rights to actual congestion paid are assigned directly to the load that paid that congestion by node. (Priority: High. First reported 2015. Status: Partially adopted.)
- The MMU recommends that, under the current FTR design, the rights to all congestion revenue be allocated as ARRs prior to sale as FTRs. Reductions in allocated revenue as a contingency for outages and increased system capability should be reserved for ARRs rather than sold in the Long Term FTR Auction. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that IARRs be eliminated from PJM's tariff, but that if IARRs are not eliminated, IARRs should be subject to the same proration rules that apply to all other ARR rights. (Priority: Low. First reported 2018. Status: Not adopted.)

FTR

- The MMU recommends that FTR funding be based on total congestion, including both day-ahead and balancing congestion. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that bilateral transactions be eliminated and that all FTR transactions occur in the PJM market. (Priority: High. First reported 2022. Status: Not adopted.)[232]
- The MMU recommends a requirement that the details of all bilateral FTR transactions be reported to PJM. (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends that PJM continue to evaluate the bilateral indemnification rules and any asymmetries they may create. (Priority: Low. First reported 2018. Status: Not adopted.)

232 If adopted, this recommendation would replace the next two recommendations.

- The MMU recommends that PJM reduce FTR sales on paths with persistent overallocation of FTRs, including a clear definition of persistent overallocation and how the reduction will be applied. (Priority: High. First reported 2013. Status: Partially adopted, 2014/2015 planning period.)
- The MMU recommends that PJM eliminate generation to generation paths and all other paths that do not represent the delivery of power to load. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that the Long Term FTR product be eliminated. If the Long Term FTR product is not eliminated, the Long Term FTR Market should be modified so that the supply of prevailing flow FTRs in the Long Term FTR Market is based solely on counter flow offers in the Long Term FTR Market. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM improve transmission outage modeling in the FTR auction models, including the use of probabilistic outage modeling. (Priority: Low. First reported 2013. Status: Not adopted.)

"Surplus"

- The MMU recommends that all FTR auction revenue be distributed to ARR holders monthly, regardless of FTR funding levels. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that, under the current FTR design, all congestion revenue in excess of FTR target allocations be distributed to ARR holders on a monthly basis. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that FTR auction revenues not be used by PJM to buy counter flow FTRs for the purpose of improving FTR payout ratios.[233] (Priority: High. First reported 2015. Status: Not adopted.)

FTR Subsidies

- The MMU recommends that PJM eliminate portfolio netting to eliminate cross subsidies among FTR market participants. (Priority: High. First reported 2012. Status: Not adopted. Rejected by FERC.)
- The MMU recommends that PJM eliminate subsidies to counter flow FTRs by applying the payout ratio to counter flow FTRs in the same way the payout ratio is applied to prevailing flow FTRs. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM eliminate geographic cross subsidies. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM examine the mechanism by which self scheduled FTRs are allocated when load switching among LSEs occurs throughout the planning period. (Priority: Low. First reported 2011. Status: Not adopted.)

FTR Liquidation

- The MMU recommends that the FTR portfolio of a defaulted member be canceled rather than liquidated or allowed to settle as a default cost to the membership. (Priority: High. First reported 2018. Status: Not adopted.)

Credit

- The MMU recommends the use of at least a 99 percent confidence interval when calculating initial margin requirements for FTR market participants, in order to assign the cost of managing risk to the FTR holders who benefit or lose from their FTR positions. (Priority: High. First reported 2021. Status: Adopted 2023.)

Section 13 Conclusion

Solutions

The annual ARR allocation should be designed to ensure that the rights to all congestion revenues are assigned to load, without requiring contract path or point to point physical or financial transmission rights that are inconsistent with the network based delivery of power and the actual way congestion is generated in PJM's security constrained LMP market. When there are binding transmission constraints and locational price differences, load pays more for energy than generation is paid to produce that energy. The difference is congestion. As a result, congestion belongs to load and should be returned to load.

233 See "PJM Manual 6: Financial Transmission Rights," Rev. 33 (Sep. 25, 2024).

The current contract path based design should be replaced with a design in which the rights to actual congestion paid are assigned directly to the load that paid that congestion by node. The assigned right should be to the actual difference between load payments, both day-ahead and balancing, and revenues paid to the generation used to serve that load. The load can retain the right to the congestion revenues or sell the rights through auctions. The correct assignment of congestion revenues to load is fully consistent with retaining FTR auctions for the voluntary sale by load of their congestion revenue rights at terms defined by load, recognizing that load has property rights to congestion.

Issues

If the original PJM FTR approach had been designed to return congestion revenues to load without the use of generation to load contract paths, and if the distortions subsequently introduced into the FTR design had not been added, many of the subsequent issues with the FTR design and complex redesigns would have been avoided. PJM would not have had to repeatedly intervene in the functioning of the FTR system in an effort to meet the artificial and incorrectly defined goal of revenue adequacy.

PJM has persistently and subjectively intervened in the FTR market in order to affect the payments to FTR holders. These interventions are not appropriate. For example, in the 2014/2015, 2015/2016 and 2016/2017 planning periods, PJM significantly reduced the allocation of ARR capacity, and FTRs, in order to guarantee full FTR funding. PJM reduced system capability in the FTR auction model by including more outages, reducing line limits and including additional constraints. PJM's modeling changes resulted in significant reductions in Stage 1B and Stage 2 ARR allocations, a corresponding reduction in the available quantity of FTRs, a reduction in congestion revenues assigned to ARRs, and an associated surplus of congestion revenue relative to FTR target allocations. This also resulted in a significant redistribution of ARRs among ARR holders based on differences in allocations between Stage 1A and Stage 1B ARRs. Starting in the 2017/2018 planning period, with the allocation of balancing congestion and M2M payments to load rather than FTRs, PJM increased system capability allocated to Stage 1B and Stage 2 ARRs, but continued to conservatively select outages to manage FTR funding levels.

PJM has intervened aggressively in the FTR market since its inception in order to meet various subjective objectives including so called revenue adequacy. PJM should not intervene in the FTR market to subjectively manage FTR funding. PJM should fix the FTR/ARR design and then should let the market work to return congestion to load and to let FTR values reflect actual congestion.

Load should never be required to subsidize payments to FTR holders, regardless of the reason.[234] The FERC order of September 15, 2016, introduced a subsidy to FTR holders at the expense of ARR holders.[235] The order requires PJM to ignore balancing congestion when calculating total congestion dollars available to fund FTRs. As a result, balancing congestion and M2M payments are assigned to load, rather than to FTR holders, as of the 2017/2018 planning period. When combined with the direct assignment of both surplus day-ahead congestion and surplus FTR auction revenues to FTR holders, the Commission's order shifted substantial revenue from load to the holders of FTRs and further reduced the offset to congestion payments by load. This approach ignores the fact that load pays both day-ahead and balancing congestion, and that actual congestion is the sum of day-ahead and balancing congestion. Eliminating balancing congestion from the FTR revenue calculation requires load to pay twice for congestion. Load pays total congestion and pays negative balancing congestion again. The fundamental reasons that there has been a significant and persistent difference between day-ahead and balancing congestion include inadequate transmission modeling in the FTR auction and the role of UTCs in taking advantage of these modeling differences and creating negative balancing congestion. There is no reason to impose these costs on load.

These changes were made in order to increase the payout to holders of FTRs who are not loads. Increasing the payout to FTR holders at the expense of the load is not a supportable market objective. PJM should implement an FTR design that calculates and assigns congestion rights to load rather than continuing to modify the current, fundamentally flawed, design.

234 Such subsidies have been suggested repeatedly. See FERC Dockets Nos. EL13-47-000 and EL12-19-000.
235 See 156 FERC ¶ 61,180 (2016), *reh'g denied*, 158 FERC ¶ 61,093 (2017).

Load was made significantly worse off as a result of the changes made to the FTR/ARR process by PJM based on the FERC order of September 15, 2016. ARR revenues were significantly reduced for the 2017/2018 FTR Auction, the first auction under the new rules. ARRs and self scheduled FTRs offset only 49.5 percent of total congestion costs for the 2017/2018 planning period rather than the 58.0 percent offset that would have occurred under the prior rules, a difference of $101.4 million.

A subsequent rule change was implemented that modified the allocation of what is termed surplus auction revenue to load. Beginning with the 2018/2019 planning period, surplus day-ahead congestion and surplus FTR auction revenue are assigned to FTR holders only up total target allocations, and then distributed to ARR holders.[236] ARR holders will only be allocated this surplus after FTRs are paid 100 percent of their target allocations. While this rule change increased the level of congestion revenues returned to load under some conditions, the rules do not recognize ARR holders' rights to all congestion revenue, and only improves congestion payouts to load when there is a surplus. There was no surplus for the 2020/2021 or 2021/2022 planning years. With this rule in effect for the 2021/2022 planning period, ARRs and self scheduled FTRs offset 31.6 percent of total congestion. There was surplus for the 2022/2023 and the 2023/2024 planning periods. However, FTR auction surplus revenues were taken from load and given to FTR holders because day-ahead congestion revenues were less than target allocations in the 2023/2024 planning period. Based on market logic, there is no such thing as surplus FTR auction revenue. FTR Auction revenue results from the market prices paid by willing FTR buyers, should be paid to ARR holders, and should not be returned to FTR buyers for any reason. ARRs and self scheduled FTRs offset only 51.3 percent of total congestion paid by ARR holders in the first ten months of the 2024/2025 planning period. Load has been underpaid congestion revenues by $4.8 billion from the 2011/2012 planning period through the first ten months of the 2024/2025 planning period. The cumulative offset for that period was only 68.7 percent of total congestion.

The complex process related to what is termed the overallocation of Stage 1A ARRs is entirely an artificial result of reliance on the contract path model in the assignment of FTRs. For example, there is a reason that transmission is not actually built to address the Stage 1A overallocation issue. The Stage 1A overallocation issue is a fiction based on the use of outdated and irrelevant generation to load contract paths to assign Stage 1A rights that have nothing to do with actual power flows.

236 163 FERC ¶ 61,165 (2018).

PJM proposed, and on March 11, 2022, FERC accepted, an increase to Stage 1A ARR allocations from 50 percent of Network Service Base Load (NSBL) to 60 percent of Network Service Peak Load (NSPL).[237] NSBL is a network service customer's contribution to the lowest daily zonal peak load in the prior twelve month period, and NSPL is a network service customer's contribution to the highest daily zonal peak load in the prior twelve month period. PJM's new ARR allocation rules have increased Stage 1A rights at the cost of Stage 1B and Stage 2 ARR allocations. More importantly, PJM's new ARR allocation rules have exacerbated the current misalignment between congestion property rights and the congestion paid by load.

Proposed Design

To address the issues with the current contract path based ARR/FTR market design, the MMU recommends that the current design be replaced with a design in which the rights to actual congestion paid are assigned directly to the load that paid that congestion by node. The assigned right would be the actual difference between load payments, both day-ahead and balancing, and revenues paid to the generation used to serve that load. The load could retain the right to the congestion or sell the right through auctions. The correct assignment of congestion revenues to load is fully consistent with retaining FTR auctions for the voluntary sale by load of their congestion revenue rights at terms defined by load.

With a network assignment of actual congestion, there would be no cross subsidies among rights holders and no over or under allocation of rights relative to actual network market solutions. There would be no revenue shortfalls as congestion payments equal congestion collected. The risk of default would be isolated to the buyer and seller of the right, and any default would not be socialized to other rights holders. In the case of a defaulting

237 See 178 FERC ¶ 61,170.

buyer, the rights to the congestion revenues would revert to the load. There would be no risk of a network right flipping in value from positive to negative, because congestion is always the positive difference between what load pays for energy and what generation is paid for energy as a result of transmission constraints.

The MMU proposal requires the calculation of constraint specific congestion and the calculation of that specific constraint's congestion related charges to each physical load bus downstream of that constraint. Under the MMU proposal, the constraint specific congestion calculated by hour, from both the day-ahead and balancing market would be paid directly to the physical load as a credit against the associated load serving entity's (LSE) energy bill. This right to the congestion is defined as the congestion revenue right (CRR) that belongs to the physical load at a defined bus, zone or aggregate. The LSE could choose to sell all or a portion of the CRR through auctions.

A CRR is the right to actual, realized network related congestion that is paid by physical load at a specific bus, zone or aggregate. Under the MMU proposal a bus, zone or aggregate specific CRR could be sold as a defined share of the actual congestion. For example, an LSE could sell 50 percent of its congestion revenue right for the planning period to a third party. The third party buyer would then be entitled to 50 percent of the congestion that is credited to that specific bus, zone or aggregate for the planning period. The remaining 50 percent of the congestion credit for the specified bus, zone or aggregate would be paid to the LSE along with the auction clearing price for the 50 percent of the CRR that was sold to the third party. Depending on actual congestion and the price paid for a CRR, an LSE selling its congestion revenue rights could be better or worse off than if it retained its rights.

Under the MMU proposal, the LSE would be able to set reservation prices in the auction for the sale of portions or all of its CRR. Third parties would have an opportunity to bid for the offered portions of the CRR, and the market for the congestion revenue associated with the specified bus, zone or aggregate would clear at a price. If the reservation price of an identified portion of the offered CRR was not met at the clearing price, that portion of the offered CRR would remain with the load. Auctions could be annual and/or monthly and/or more frequent.

Under the MMU proposal, point to point rights (FTRs) could exist as a separate, self-funded hedging product based on simultaneously feasible prevailing and counter flows in a PJM managed network based auction. The only supply and the only source of revenues in the point to point market for prevailing flow FTRs would be counter flow offers and direct payments for specific rights.