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State of the Market Report for PJM

Monitoring Analytics, LLC

Independent
Market Monitor
for PJM

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Preface

The PJM Market Monitoring Plan provides:

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

Accordingly, Monitoring Analytics, LLC, which serves as the Market Monitoring Unit (MMU) for PJM Interconnection, L.L.C. (PJM), and is also known as the Independent Market Monitor for PJM (IMM), submits this 2026 Quarterly State of the Market Report for PJM: January through March. [2] [3]

1 PJM Open Access Transmission Tariff (OATT) Attachment M (PJM Market Monitoring Plan) § VI.A. Capitalized terms used herein and not otherwise defined have the meaning provided in the OATT, PJM Operating Agreement, PJM Reliability Assurance Agreement (RAA), the Consolidated Transmission Owners Agreement (CTOA) or other tariffs that PJM has on file with the Federal Energy Regulatory Commission (FERC or Commission).
2 OATT Attachment M.
3 All references to this report should refer to the source as Monitoring Analytics, LLC, and should include the complete name of the report: *2026 Quarterly State of the Market Report for PJM: January through March.*

1. Introduction

Q1 2026 in Review

Reliability is a core goal of PJM. Reliability should remain 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. That is the definition of affordability. 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 2026. The results of the energy market were competitive in the first three months of 2026. The results of the 2025/2026, 2026/2027, and 2027/2028 capacity markets 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. Well designed markets define the tradeoff between cost and reliability.

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 immediate short term conditions including weather, the existing generation fleet, unit availability, actual load, transmission limitations, and fuel availability and costs. The capacity market results incorporate load forecasts and the response of investors in resources to expected market conditions. 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. It would be a mistake to attempt to engineer the energy market to administratively shift some of the capacity market missing money to the energy market. No good reason has been provided for doing so. Current efforts to do that in the RCSTF are not transparent or well defined. The recovery of the missing money in the capacity market is, by definition, administrative and will be no less administrative if somehow included in the energy market. Recovery of the missing money in the energy market is hard to do and likely to undercut the goals of stability and predictability in the markets. It has proven to be a mistake to attempt to engineer the capacity market using the flawed ELCC approach or arbitrary changes to the VRR curve or undermining the net energy market revenue offset in individual offers and the VRR curve.

There are clear warning signs for the capacity market and for PJM reliability. The capacity market was short of meeting its reliability objective in the most recent capacity auctions for the 2026/2027 BRA and the 2027/2028 BRA. PJM was also short of meeting its reliability target as of June 1, 2025, on an ICAP and a UCAP basis. The amount that PJM is short capacity grew from 208.7 MW in the 2026/2027 BRA to 6,516.6 MW in the 2027/2028 BRA. The price impacts on customers have been very large and are not reversible. The price impacts will be even larger in the near term unless the issues associated with data center load are addressed in a timely manner, prior to the next BRA, scheduled for June 2026.

Data center load growth is the primary reason for recent and expected capacity market conditions, including total forecast load growth, the tight supply and demand balance, and high prices. But for data center growth, both actual and forecast, the capacity market would not have seen the same tight supply demand conditions, the same high prices observed in the 2025/2026 BRA, the 2026/2027 BRA, and the 2027/2028 BRA, and the currently expected tight supply conditions and high prices for subsequent capacity auctions. Forecast data center load growth has been the primary cause to date and the accuracy of those forecasts is highly questionable.

Holding aside all the other issues associated with the 2025/2026 BRA, 2026/2027 BRA and 2027/2028 BRA, existing and forecast data center load by itself resulted in a significant increase in BRA revenues for each of the delivery years. Based on actual auction clearing prices and quantities and uplift MW, inclusion of existing and forecast data center load growth resulted in a combined total increase in capacity market revenues for the 2025/2026 BRA, the 2026/2027 BRA, and the 2027/2028 BRA of $23,100,955,341.[1] This total will continue to grow until the issues associated with the addition of large data center loads are addressed.

1 See the *"Analysis of the 2027/2028 RPM Base Residual Auction – Part A,"* (January 5, 2026). <https://www.monitoringanalytics.com/reports/Reports/2026/IMM_Analysis_of_the_20272028_RPM_Base_Residual_Auction_Part_A_20260105.pdf>

The impact on the 2026/2027 and 2027/2028 BRA revenues would have been higher had PJM not used the Agreement VRR curve.[2] If the 2026/2027 BRA had been run with PJM's proposed unrestricted VRR curve, total revenues would have been $19,294,286,100, an increase of $3,169,915,210, or 19.7 percent, compared to the actual auction results. If the 2027/2028 BRA had been run with PJM's proposed unrestricted VRR curve, total revenues would have been $26,324,850,846, an increase of $9,913,272,621, or 60.4 percent, compared to the actual auction results. In other words, the inclusion of data center load in the last two auctions increased customers' bills by $13,768,851,483, even with the maximum price from the Agreement in place. The market distorting effect of data center load would have been $26,852,039,314 but for the Agreement. The result of the Agreement was to reduce that impact by $13,083,187,831. Contrary to assertions that the Agreement was a typical regulatory response to high prices, the maximum price resulting from the Agreement is more consistent with a competitive outcome than would have occurred without the Agreement. The Agreement was a logical and reasonable response to the unmitigated market distortions created by unsubstantiated data center load forecasts that should not have been included in the market clearing in the first place.

The longstanding and recently revived assertion that the Agreement is evidence of a so called credibility trap is not correct. The assertion that PJM market prices are never allowed to reflect shortage is demonstrably false. The assertion that there should not be a regulatory response to extreme prices that do not reflect market fundamentals is wishful thinking on the part of some but not founded in the fact that FERC uses markets to create just and reasonable rates. That argument also relies on the paternalistic assertion that EDCs and LSEs should be required to hedge their obligations and the incorrect conclusion that if there had been hedges, load would not be paying the excess costs imposed by data center loads. Hedges can never beat the market over time because every hedge has a buyer and a seller.

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

There is nothing market based about the PJM VRR curve that would have been in place but for the maximum price in the Agreement. Any assertions that the PJM VRR curve represents a true market solution are unsupported and fail to recognize the distortionary effects of including unsubstantiated forecast data center load. The PJM VRR curve is based on a faulty calculation of Gross CONE and Net CONE.[3] The PJM VRR curve, effective for the 2028/2029 Base Residual Auction, includes a maximum price equal to the greater of 1.15 times Gross CONE minus 0.75 times Net EAS (1.15*Gross CONE – 0.75*EAS), or 0.2 times Gross CONE. There is no reason to inflate the maximum price and PJM has provided no logical rationale for this overstatement.

Large data center load additions have already had a significant and irreversible impact on PJM customers that will be paid through May 31, 2028, and will have additional significant impacts on other customers as a result of higher transmission costs, higher energy market prices and higher capacity market prices.

Some participants contend that PJM markets are just facing an unexpected growth in demand and that the normal supply and demand dynamics should be allowed to play out without recognition of these unique circumstances. This position is that prices should be allowed to rise, incentives to build generation will result, and supply and demand will return to balance. This simplistic view ignores the fact that it is the unexpected addition of extraordinarily high levels of data center load (largely based on unsubstantiated forecasts) that have resulted in the supply-demand imbalance. This position also ignores related underlying issues including the excessive maximum price in the capacity market, the uncertainty and understatement of available capacity that result from ELCC and the uncertainty hangover from the prior queue management issues.

Other participants take the more radical view that the owners of existing capacity should be able to sell their resources to data centers directly and without limit. The proponents of that view have failed to explain why it is reasonable to create chaos for all the other PJM customers. Removal of significant levels of capacity from the PJM market that serves all other

3 *See* the Comments of the Independent Market Monitor for PJM, Docket No. ER26-455, (January 20, 2026).

customers would create extreme price impacts in the energy and capacity markets, reliability shortfalls in the capacity market, and blackouts from inadequate energy.

Markets cannot automatically solve all problems and it is not enough to simply assert that the market will solve all the problems associated with data center load. The wholesale power markets created by FERC need rules and include rules. FERC relies on competitive markets to be a more effective substitute for traditional 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, in significant part because there is endemic structural market power in the capacity market. The decisions about the interconnection of large new data center loads when there is not enough capacity to maintain system reliability are public, regulatory decisions because they are about competitive outcomes that are in the interests of all market participants. PJM markets are not laissez faire markets.

There is a path forward that does not use the current data center issues as a pretext for redefining fundamental elements of the PJM market design. That path starts with the recognition that the source of the current issues is data center load. The next step is to provide a mechanism for data center load to be served reliably while not distorting prices for all other customers. That step would remove data center load from the next BRAs and rely on bilateral contracts between data centers and generators, whether from negotiated bring your own new generation ("BYONG") contracts or from a reliability backstop auction. The rest is details. In contrast, leaving forecast data center load in the next BRAs, as PJM proposes, will ensure that other customers will continue to pay the price for the addition of data center load.

It is clear that continuing to simply accept the interconnection of large data center loads that cannot be served reliably because there is not adequate dispatchable capacity, is not a reasonable path forward and is not an efficient or competitive market solution and is not a solution of any kind. That path leads to continued shortfalls, increased reliability issues, continued maximum prices, and continued calls to abandon markets.

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

The market solution is to require data centers to bring their own new generation. This would include an expedited fast track load and generation interconnection process for large new data center loads that bring their own new generation with locational and temporal characteristics reasonably matched to their load profile. The preferred solution would include creating a queue for the addition of large new data center loads, which would not be interconnected until there is adequate capacity to serve them. Another solution (connect and manage) would require data centers that do not bring their own new generation to be curtailable prior to current demand side customers but without the pretense that the data centers are providing demand response for which they should be paid. There are no clear rules governing curtailment priorities and order. Data centers do not want to be curtailable. Data centers are already critical loads in many applications because they are embedded in the workings of the economy and society. Given the level of data center load growth, this curtailability option would provide an incentive to bring new generation, if enforced on a specific data center basis. This broad bring your own new generation solution to the issues created by the addition of unprecedented amounts of large data center load does not require a continued massive wealth transfer through ongoing shortage pricing. It is essential to have a pragmatic market solution that is consistent with and sustains efficient and competitive PJM markets rather than to create the conditions for a return to cost of service regulation or a variant of cost of service regulation.

In response to the proposed use of a backstop auction to create a market mechanism to facilitate data center load bringing its own new generation, the

MMU has made a proposal.[4] The MMU design creates a dedicated mechanism for new large data center load designed to complement, not replace, PJM's existing RPM construct. It is intended to ensure long term resource adequacy for data center load by directly linking new data center load with dedicated new generation, creating transparent investment signals based on a 15 year contract term. All data center load that was not online on June 1, 2026, would be required to participate in the backstop auction or to commit to the BYONG option. Data center load would have the option to commit to a specific future BYONG plan and not be included in the auction. If such data center load did not bring new generation, that load would be curtailable if that load is allowed to come online.

In brief, the MMU proposal for the backstop auction is to first run the next BRAs without the inclusion of any forecast data center load in order to meet the organic load, and then to run a full BRA design auction just for data center load. This would include the LDA location and MW of each data center that participates, the LDA location and MW of proposed generation that participates, full PJM CETO/CETL parameters net of the impacts from the prior BRA and any resultant locational price separation. In this backstop auction, the demand for capacity would be equal to specific demand for 15 year capacity from individual data centers, plus the required reserve margin for each data center. Sellers in this backstop auction would be new generation only. This approach also eliminates the need to rely on unsubstantiated data center load forecasts.

When the clearing process is complete and each generation offer is associated with an identified data center load following an algorithmic process, the generators and data center loads would enter into bilateral contracts that do not permit any cost or risk shifting to other customers. The contracts would be based on a tariff defined standard contract. The risks associated with the load changing or withdrawing and generation changing or failing would be fully addressed in the bilateral contracts. The risks associated with changes in ELCC values would be fully addressed in the bilateral contracts. New capacity resources clearing in the auction would have a starting ELCC based on the recent EFORd performance of comparable generation and would have unit specific ELCC values based on unit performance and therefore subject to management by the generator for the entire contract term.

When the bilateral contracts are final, including bilateral contracts reached under the BYONG option, the data center load plus the reserve margin and the corresponding capacity would be included in future BRAs as price takers.

Given that capacity market revenues generally comprise less than half of revenues to PJM combined cycle resources, in order to meet the intended incentive goal, the total payments received for new generation should equal Gross CONE, including both net revenue from the energy and ancillary services markets and capacity payments. The net revenues would be explicitly incorporated. The actual annual payments under the contracts would include the defined energy and ancillary service net revenues calculated annually for each year and the remaining Net CONE not covered by the net revenues. The contracts would be for total payments including energy and ancillary services net revenues and the remaining net cost of capacity.

In order to address any potential jurisdictional issues, LSEs would be required, as a condition of service, in the RAA, to require that all data centers that they serve have a bilateral contract in place with a source of generation for at least 15 years. The bilateral contracts would be for generation that can serve the location of the data center and that has energy output reasonably matched to the load of the data center. The bilateral contracts would address all pricing and risk issues solely between the parties with no recourse to other customers.

Under the MMU proposal, neither the EDCs nor the LSEs are the counterparty to the contracts and the EDCs and the LSEs and their other customers are not at risk for any contract related issues. The data center and the capacity seller are the counterparties to the contracts. PJM and other PJM participants provide no credit support of any kind for the contracts. There is no recourse to PJM or its members. Credit issues are entirely between the parties to the bilateral contracts.

4 See Monitoring Analytics, LLC, Reliability Backstop Auction Design Proposal – V4, which can be found at <https://www.monitoringanalytics.com/reports/Presentations/2026/IMM_Reliability_Backstop_WS_%20Backstop_Auction_Design_Proposal-V4_20260508.pdf> .

This proposal is fully consistent with both the Principles and the Pledge.[5] [6] The Principles and the Pledge establish two essential core principles, that the data centers must bear their own costs and risks and not shift them to other customers, and that the data centers must bring their own new generation in any one of a number of forms or be fully curtailable. Contrary to almost all the other proposals for addressing the issues, including the other backstop auction proposals, the MMU proposal is designed to ensure that data centers do not shift costs and risks to other customers. The costs and risks must be assigned directly to data centers and not allocated. Assigned implies a binding contract solely between the data center and generator counterparties without credit or cost support from other customers. Allocation is a regulatory concept that implies a fluid mechanism that is not binding and that could be modified to allocate these data center costs and risks to other customers in the present or in the future.

All loads should be served. All loads should be served reliably. The process for adding large data center 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 and should be on the grid and the grid is highly interconnected.

The temptation to create complex regulatory structures to shift data center costs and risks to other customers should be resisted. The other backstop proposals generally shift significant risk to other PJM customers. Other PJM customers, whether residential, commercial or industrial, should not be treated as a free source of insurance, or collateral, or financing for data centers. Yet that is what most of the proposals related to a backstop auction actually do. Although presented in superficially sophisticated terms, the proposals would shift risk to other PJM customers who would have no choice in the matter. Making PJM the counterparty to transactions between data centers and generators would mean that if one or both failed, PJM customers would pay the default value. That is true regardless of whether the counterparty status was designed to be direct or through a related risk instrument. Making EDCs the counterparty to transactions would shift risk to other EDC customers. Making LSEs the counterparty to transactions and requiring all LSEs to bilaterally acquire capacity resources would shift risk to the other customers of each LSE in addition to radically changing the capacity market design and returning to the pre-markets period when generation owners exercised market power against competitive LSEs. The option of EDCs building generation under cost of service regulation is another mechanism for shifting costs and risks to other EDC customers. If the new generation is in the utility rate base, all customers will pay for it. Running a backstop auction with all load, or just for the shortfall in the prior BRA, including forecast data center load, directly increases costs for all other customers and imposes the risks associated with uncertain data center forecasts on other customers. The issue of shifting risk is not a general concern to be put off to the uncertain future but must be a core element of any backstop proposal.

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 2026 from the first three months of 2025. The real-time load-weighted average LMP in the first three months of 2026 increased $35.37 per MWh, or 67.8 percent, from the first three months of 2025, from $52.20 per MWh to $87.57 per MWh.

Of the $35.37 per MWh increase in the price of energy, $14.92 per MWh (42.2 percent) was the fuel and consumables cost components of LMP, $9.73 per MWh (27.5 percent) was the transmission constraint penalty factor component of LMP, $3.56 per MWh (10.1 percent) was the market power components of LMP, $1.26 per MWh (3.6 percent) was the emissions cost components of LMP, and $0.85 per MWh (2.4 percent) was the scarcity component of LMP. The strike prices of pre-emergency demand response called on by PJM during the Winter Storm Fern increased the LMP by $0.18 per MWh, 0.5 percent of the increase in LMP. The LMP increase would have been higher but for the $3,700.00 per MWh administrative cap. The administrative cap reduced the LMP by $0.03 per MWh, a 0.1 percent decrease.

5 See Statement of Principles Regarding PJM, National Energy Dominance Council and PJM State Governors (February 15, 2026), <https://www.energy.gov/documents/statement-principles-regarding-pjm>.

6 See Fact Sheet: President Donald J. Trump Advances Energy Affordability with the Ratepayer Protection Pledge, The White House (March 4, 2026); Ratepayer Protection Pledge, The White House (March 4, 2026), <https://www.whitehouse.gov/fact-sheets/2026/03/fact-sheet-president-donald-j-trump-advances-energy-affordability-with-the-ratepayer-protection-pledge/>.

The total cost of wholesale power increased in the first three months of 2026 compared to the first three months of 2025. Energy (71.5 percent), capacity (13.0 percent) and transmission (13.8 percent) are the three largest components of the total cost of wholesale power, comprising 98.3 percent of the total cost per MWh in the first three months of 2026. The total cost of wholesale power increased by $58.75 per MWh, or 75.5 percent, from $77.78 per MWh in the first three months of 2025 to $136.53 per MWh in the first three months of 2026. Of the $58.75 increase, the total cost of energy increased by $42.90 per MWh, 78.5 percent, the total cost of capacity increased by $14.21 per MWh, 398.1 percent, and the total cost of transmission increased by $0.94 per MWh, 5.3 percent.

In the first three months of 2026, generation from coal units decreased 1.7 percent, generation from natural gas units increased 4.2 percent, generation from oil units increased 43.2 percent, generation from wind units decreased 4.7 percent, and generation from solar units increased 15.0 percent compared to the first three months of 2025.

Energy market net revenue is a key measure of overall market performance as well as a measure of the incentive to invest in generation to serve PJM markets. 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 2026 compared to the first three months of 2025. The net effects were that in the first three months of 2026, energy market theoretical net revenues increased by 213 percent for a new combustion turbine (CT), increased by 144 percent for a new combined cycle (CC), increased by 199 percent for a new coal plant (CP), increased by 64 percent for a new nuclear plant, increased by 1,326 percent for a new diesel (DS), increased by 29 percent for a new onshore wind installation, increased by 65 percent for a new offshore wind installation and increased by 10 percent for a new solar installation.

The real-time hourly average load in the first three months of 2026 increased by 3.1 percent from the first three months of 2025, from 95,801 MWh to 98,749 MWh.

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: implement a bring your own new generation option for the interconnection of large new data center loads including a targeted backstop auction; improve the ELCC/CP capacity market design; enhance the PJM reserve products to address intermittent resource uncertainty; create rules for the competitive and transparent advanced commitment of generation for extreme weather; identify the availability of firm gas supply and gas transportation; require generators to procure natural gas transportation; 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 assertion that yet another holistic review of PJM markets is required or is a panacea is, for many, merely a euphemism for raising prices, although that is not the stated intent of the PJM Board.[7] PJM has pursued a range of arbitrary mechanisms for raising prices, from extreme ORDCs, to fast start pricing, to unsupported increases in reserve requirements, to transmission constraint penalty factors, to PJM's version of ELCC, to modified capacity market demand curves that artificially reduce the net energy market revenue offset.

The goal should be to continue to refine the PJM market design in order to permit supply and demand fundamentals to be reflected in prices in a transparent and predictable manner. The goal should be to avoid micromanaging market design features to achieve specific price outcomes or to continuously change the market rules in an effort to reach a desired result. Capacity market prices will be higher for organic load as the higher marginal costs of capacity are

7 See the PJM Board letter of January 16, 2026 <https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/2026/20260116-pjm-board-letter-re-results-of-the-cifp-process-large-load-additions.pdf>.

revealed in the capacity market. Energy market prices reflect input costs whether higher or lower.

PJM markets do not need a holistic review. The focus should be on the fact that PJM markets and the underlying software need to be operated as efficiently as possible, relying on fully updated software. PJM's improved and approved market power mitigation process cannot work until PJM commitment and dispatch software is upgraded. These upgrades have been delayed by multiple years and have no firm expected implementation date. PJM's communications software and methods for providing information to generating units need to be fully updated. PJM operators need to have tools for advance scheduling and fuel inventory tracking that permit the efficient use of resources under extreme conditions.

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. However, 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 and establish effective performance incentives that apply every day. 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. There should be an expedited interconnection process for large data center load additions that bring their own generation. 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 current and potential market participants and stakeholders, PJM states, PJM customers, 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, 2025 and 2026[8]

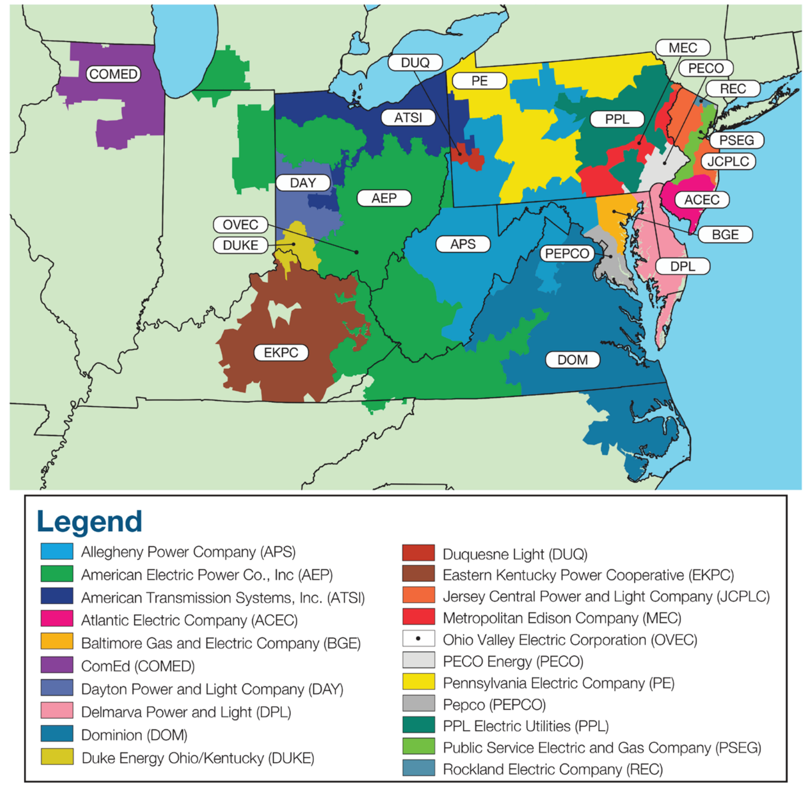
	Jan-Mar 2025	Jan-Mar 2026	Percent Change
Average Hourly Load Plus Exports (MWh)	102,154	104,630	2.4%
Average Hourly Generation Plus Imports (MWh)	104,313	106,982	2.6%
Peak Load Plus Net Export (MWh)	147,704	137,037	(7.2%)
Peak Load Excluding Export (MWh)	140,043	135,722	(3.1%)
Installed Capacity at March 31 (MW)	179,017	184,191	2.9%
Load Weighted Average Real Time LMP ($/MWh)	$52.20	$87.57	67.8%
Total Congestion Costs ($ Million)	$503.30	$2,015.20	300.4%
Total Uplift Credits ($ Million)	$470.2	$979.7	108.4%
Total PJM Billing ($ Billion)	$18.69	$36.35	94.5%

PJM Market Background

The PJM Interconnection, L.L.C. (PJM) operates a centrally dispatched, competitive wholesale electric power market that, as of March 31, 2026, had installed generating capacity of 184,191 megawatts (MW) and 1,123 members including market buyers, sellers and traders of electricity in a region including more than 67 million people in 21 control zones and 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).[9] [10]

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.

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



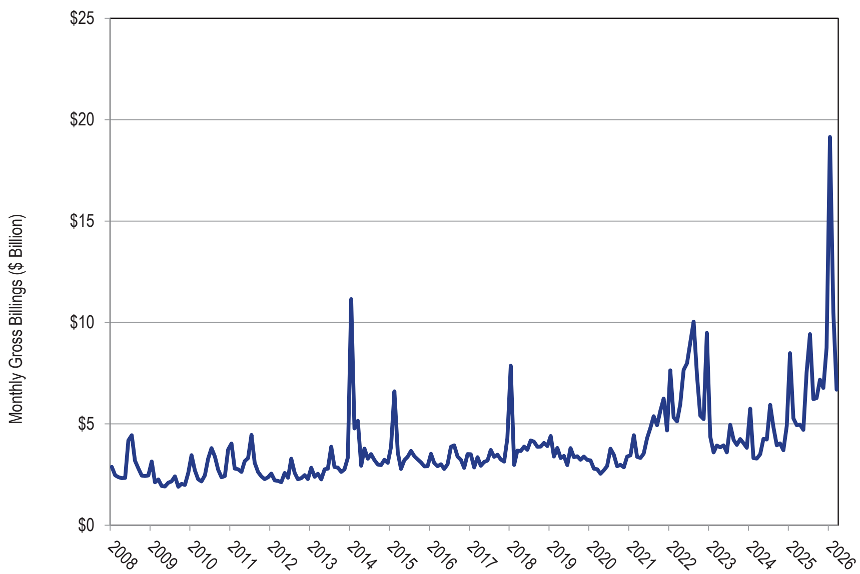
In the first three months of 2026, PJM had gross billings of $36.35 billion, an increase of 94.5 percent from $18.69 billion in the first three months of 2025. (Figure 1-2).

8 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.

9 See PJM. "Member List," which can be accessed at: <http://pjm.com/about-pjm/member-services/member-list.aspx>.

10 See PJM. "Who We Are," which can be accessed at: <*http://pjm.com/about-pjm/who-we-are.aspx*>.

Figure 1-2 Monthly PJM billings ($ Billion): 2008 through March 2026 [11]



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. 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. PJM replaced EFORd as the basis for derating ICAP to UCAP in the capacity market with ELCC effective with the Base Residual Auction run in July 2024 for 2025/2026. PJM replaced the two product, two signal regulation market with a single product, single signal regulation market effective October 1, 2025.

Conclusions

This report assesses the competitiveness of the markets managed by PJM in the first three months of 2026, 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

11 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.

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 2026.

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 90.0 percent of the days in the first three months of 2026. The hourly HHI (Herfindahl-Hirschman Index) results indicate that the PJM aggregate energy market in the first three months of 2026 was, on average, unconcentrated by FERC HHI standards. The average HHI was 753 with a minimum of 621 and a maximum of 954. The baseload segment of the supply curve was unconcentrated. The intermediate segment of the supply curve was moderately concentrated. 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 noncompetitive 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 be an issue. 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.[12] 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.[13] 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.[14] 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.[15] [16] [17] 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

12 OATT Attachment M (PJM Market Monitoring Plan).
13 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).
14 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.
15 175 FERC ¶ 61,231 (2021).
16 185 FERC ¶ 61,158 (2023).
17 189 FERC ¶ 61,060 (2024).

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.

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.[18] The conclusions for 2025 and the first three months of 2026 are a result of the MMU's evaluation of the 2025/2026, 2026/2027, and 2027/2028 Base Residual Auctions.[19] [20] [21] [22] [23] [24] [25] [26] [27] [28] [29]

18 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.

19 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>.

20 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>.

21 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>.

22 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>.

23 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>.

24 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>.

25 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part G Revised," (June 3, 2025) <https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_G_20250603_Revised.pdf>.

26 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part H," (July 31, 2025) <https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_H_20250731.pdf>.

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

28 See "Analysis of the 2026/2027 RPM Base Residual Auction - Part B," (March 3, 2026) <https://www.monitoringanalytics.com/reports/Reports/2026/IMM_Analysis_of_the_20262027_RPM_Base_Residual_Auction_Part_B_20260303.pdf>.

29 See "Analysis of the 2027/2028 RPM Base Residual Auction – Part A," (January 5, 2026) <https://www.monitoringanalytics.com/reports/Reports/2026/IMM_Analysis_of_the_20272028_RPM_Base_Residual_Auction_Part_A_20260105.pdf>.

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**

- 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.[30] 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.[31]
- Participant behavior was evaluated as not competitive in the 2026/2027 BRA. Effective with the 2026/2027 Delivery Year, the market seller offer cap definition was modified to include unit specific standalone Capacity Performance Quantifiable Risk (CPQR) and segmented unit specific offer caps.[32] The offers in the 2026/2027 BRA included those based on standalone CPQR offer caps. 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.
- Market performance was evaluated as not competitive based on the 2026/2027 Base Residual Auction as a result of 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

30 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.

31 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.

32 190 FERC ¶ 61,117 (2025).

the failure to recognize and address the role of large data center loads is a direct cause of higher prices and will continue to result in even higher prices unless the related issues are addressed.

- Market design was evaluated as mixed because while there are many positive features of the capacity market design and some of the MMU's recommendations were implemented in the 2026/2027 BRA, there are several features of the RPM design which still threaten competitive outcomes. These include the lack of a queue for the addition of large new data center loads, details of PJM's ELCC implementation, the definition of market seller offer caps, the failure to apply the RPM must offer requirement to demand resources, the inclusion of performance assessment interval (PAI) penalties, 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.[33]

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 2026.

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 unconcentrated in the real-time market. The MAD Reserve Subzone was highly 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 operating reserve demand curve (ORDC). In an attempt to counter poor unit specific synchronized reserve performance, PJM unilaterally and inappropriately extended the first step of the ORDC for synchronized reserve, known as the synchronized reserve reliability requirement, in May 2023, raising prices for synchronized reserves, nonsynchronized reserves and energy.

- 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 2026.

Table 1-5 The nonsynchronized 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 nonsynchronized reserve market structure was evaluated as not competitive due to supplier concentration for primary reserve. The RTO Reserve Zone was moderately concentrated in the day-ahead market and moderately concentrated in the real-time market. The MAD Reserve

33 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).

Subzone was highly 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 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 operating reserve demand curve (ORDC). In an attempt to counter poor unit specific synchronized reserve performance, PJM unilaterally and inappropriately extended the first step of the ORDC for synchronized reserve, known as the synchronized reserve reliability requirement, in May 2023. Because the first step of the ORDC for primary reserve, known as the primary reserve reliability requirement, is based on the synchronized reserve reliability requirement, the primary reserve reliability requirement was consequently also extended, raising prices for synchronized reserves, nonsynchronized reserves, and energy.
- Market design was evaluated as flawed based on PJM's modifications to the first step of the ORDC.

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 2026.

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 due to the lack of supplier concentration for 30-minute reserve. The RTO Reserve Zone was unconcentrated in the day-ahead market and unconcentrated in the real-time 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 2026.

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 84.5 percent of half hour market intervals in the first three months of 2026.
- Participant behavior in the PJM Regulation Market was evaluated as competitive in the first three months of 2026 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 post-October 1, 2025, market results include an improved approach to opportunity cost but include an incorrect definition of opportunity cost that has significant effects on

prices. The definition of performance is also incorrect. The post-October 1, 2025, design is a significant improvement over the pre-October 1, 2025, design although there are significant issues in the new design.

FTR Auction Market Conclusion

The *2026 Quarterly State of the Market Report for PJM: January through March* focuses on the 2025/2026 planning period as well as the 2025/2028 Long Term auction, the 2025/2026 Annual FTR auction and the 2025/2026 ARR allocation, specifically covering June 1, 2025, through March 31, 2026. 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 2026. [34]

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 2025/2028 Long Term FTR Auction, the 2025/2026 Annual FTR Auction and each period of the Monthly Balance of Planning Period Auctions for prevailing flow FTRs. The ownership of FTR obligations is unconcentrated or moderately concentrated for each period of the Monthly Balance of Planning Period Auctions for counter flow FTRs. The ownership of FTR options is moderately or highly concentrated for every Monthly FTR Auction period and unconcentrated for the 2025/2026 Annual FTR Auction. Ownership of current FTRs is disproportionately (89.2 percent) by financial participants. The ownership of ARRs is unconcentrated.

34 The MMU identified missing and erroneous distribution factors and shadow prices, primarily within the pricing run. The calculation of generator sensitivity factors requires accurate distribution factors and shadow prices. Where available, MMU used distribution factors from the dispatch run. MMU also calculated missing shadow prices for the relevant transmission constraints when feasible. This approach reduced the impact of the errors to 0.2 percent of all FTR target allocations within the affected month. Figures and Tables that are affected by this error are indicated with a footnote.

- 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.[35] 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.[36]

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.

35 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).

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

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.[37] The MMU has direct, confidential access to FERC.[38] The MMU may also refer matters to the attention of state commissions.[39]

The MMU monitors market behavior for violations of FERC Market Rules and PJM Market Rules, including the actual or potential exercise of market power.[40] 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..."[41 42 43] The MMU also monitors PJM for compliance with the rules, in addition to market participants.[44]

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

37 OATT Attachment M § IV.

38 OATT Attachment M § IV.K.3.

39 OATT Attachment M § IV.H.

40 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.")

41 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.

42 OATT § I.1.

43 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.

44 OATT Attachment M § IV.C.

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.[45]

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.[46] [47] [48] [49]

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.

45 OATT Attachment M–Appendix § II.E.
46 OATT Attachment M–Appendix § II.B.
47 OATT Attachment M–Appendix § II.C.
48 OATT Attachment M–Appendix § IV.
49 OATT Attachment M–Appendix § VII.

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.[50] [51]

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.[52]

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.[53] The MMU initiates and proposes changes to the design of such markets or the PJM Market Rules in stakeholder or regulatory proceedings.[54] 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.[55] 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 the PJM Board.[56] The MMU may provide in its annual, quarterly and other reports "recommendations regarding any matter within its purview."[57]

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

50 OATT Attachment M–Appendix § II(p).
51 OATT Attachment M–Appendix § III.
52 OA Schedule 6 § 1.5.
53 OATT Attachment M § IV.D.
54 *Id.*
55 *Id.*; see also, e.g., 171 FERC ¶ 61,039; 167 FERC ¶ 61,084 at PP 70–76, *reh'g denied*, 168 FERC ¶ 61,141.
56 *Id.*
57 OATT Attachment M § VI.A.

competitive results in PJM markets and for continued improvements in the functioning of PJM markets. [58]

In this *2026 Quarterly State of the Market Report for PJM: January through March*, the MMU includes one new recommendation made for the first three months of 2026.

New Recommendation from Section 10, Ancillary Services

- The MMU recommends that if a unit sets its economic maximum at a value greater than its regulation maximum, the lost opportunity cost (LOC) of the unit should be calculated assuming the economic maximum of the unit is equal to the regulation maximum of the unit. The MMU recommends that, in cases where offered ramp is greater than actual ramp, the actual ramp be used to calculate the LOC of the unit. The MMU recommends that these fixes to the LOC logic be implemented prior to implementing Phase 2 of the regulation market design. (Priority: High. New Recommendation. Status: Not adopted.)

Total Cost of Wholesale Power

The total cost of wholesale power is the average total cost per MWh of wholesale electricity in PJM markets.[59] 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 2025 and 2026.

The total costs shown in Table 1-9 equal the total cost per MWh, by category, multiplied by the total real time load. [60] 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.

The total cost of wholesale power increased in the first three months of 2026 compared to the first three months of 2025. Energy (71.5 percent), capacity (13.0 percent) and transmission (13.8 percent) are the three largest components of the total cost of wholesale power, comprising 98.3 percent of the total cost per MWh in the first three months of 2026 (Table 1-9). The total cost of energy per MWh increased by $42.90 from $54.67 in the first three months of 2025 to $97.56 in the first three months of 2026, an increase of 78.5 percent. The total cost of capacity per MWh increased by $14.21 from $3.57 in the first three months of 2025 to $17.78 in the first three months of 2026, an increase of 398.1 percent. The total cost of transmission per MWh increased by $0.94 from $17.86 in the first three months of 2025 to $18.80 in the first three months of 2026, an increase of 5.3 percent. The total cost per MWh of wholesale power increased by $58.75 from $77.78 in the first three months of 2025 to $136.53 in the first three months of 2026, an increase of 75.5 percent.

58 18 CFR § 35.28(g)(3)(ii)(A); see also OATT Attachment M § IV.D.

59 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.

60 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/IMM_Total_Price_Calculation_Documentation_20241011.pdf>.

Table 1-9 Total cost per MWh by category: January through March, 2025 and 2026[61] [62] [63]

Category	2025 (Jan-Mar) $/MWh	2025 (Jan-Mar) ($ Millions)	2025 (Jan-Mar) Percent of Total	2026 (Jan-Mar) $/MWh	2026 (Jan-Mar) ($ Millions)	2026 (Jan-Mar) Percent of Total	Percent Change
Energy	$54.67	$11,307	70.3%	$97.56	$20,800	71.5%	78.5%
Day Ahead Energy	$53.00	$10,963	68.1%	$95.06	$20,266	69.6%	79.3%
Balancing Energy	$1.09	$226	1.4%	$2.03	$433	1.5%	85.7%
ARR Credits	($1.17)	($242)	(1.5%)	($2.23)	($476)	(1.6%)	90.6%
Self Scheduled FTR Credits	($0.91)	($189)	(1.2%)	($1.88)	($400)	(1.4%)	105.1%
Balancing Congestion	$0.97	$200	1.2%	$1.00	$213	0.7%	3.3%
Emergency Energy	$0.00	$0	0.0%	$0.09	$20	0.1%	0.0%
Inadvertent Energy	($0.01)	($2)	(0.0%)	$0.04	$9	0.0%	(467.1%)
Load Response - Energy	$0.03	$7	0.0%	$0.09	$19	0.1%	171.8%
Emergency Load Response	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Energy Uplift (Operating Reserves)	$2.27	$469	2.9%	$4.61	$983	3.4%	103.2%
Marginal Loss Surplus Allocation	($0.76)	($156)	(1.0%)	($1.56)	($334)	(1.1%)	107.2%
Market to Market Payments	$0.15	$31	0.2%	$0.31	$66	0.2%	104.9%
Capacity	$3.57	$738	4.6%	$17.78	$3,790	13.0%	398.1%
Capacity (Capacity Market and FRR)	$3.44	$712	4.4%	$18.34	$3,910	13.4%	433.0%
Capacity Part V (RMR)	$0.13	$27	0.2%	($0.56)	($119)	(0.4%)	(533.1%)
Load Response - Capacity	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Transmission	$17.86	$3,694	23.0%	$18.80	$4,008	13.8%	5.3%
Transmission Service Charges	$15.10	$3,124	19.4%	$16.23	$3,461	11.9%	7.5%
Transmission Enhancement Cost Recovery	$2.66	$550	3.4%	$2.48	$528	1.8%	(6.9%)
Transmission Owner (Schedule 1A)	$0.09	$19	0.1%	$0.09	$19	0.1%	(3.1%)
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	$1.02	$212	1.3%	$1.73	$369	1.3%	69.0%
Reactive	$0.45	$92	0.6%	$0.40	$86	0.3%	(9.8%)
Regulation	$0.32	$67	0.4%	$1.02	$217	0.7%	214.5%
Black Start	$0.08	$16	0.1%	$0.05	$11	0.0%	(31.5%)
Synchronized Reserves	$0.16	$33	0.2%	$0.22	$47	0.2%	41.0%
Secondary Reserves	$0.00	$1	0.0%	$0.02	$4	0.0%	765.9%
Non-Synchronized Reserves	$0.01	$3	0.0%	$0.01	$2	0.0%	(29.5%)
Day Ahead Scheduling Reserve (DASR)	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Administration	$0.66	$137	0.9%	$0.66	$141	0.5%	0.1%
PJM Administrative Fees	$0.61	$127	0.8%	$0.61	$131	0.4%	(0.2%)
NERC/RFC	$0.04	$9	0.1%	$0.05	$10	0.0%	6.2%
RTO Startup and Expansion	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Other	$0.00	$1	0.0%	$0.00	$1	0.0%	(7.3%)
Total Cost ($/MWh)	$77.78	$16,087	100.0%	$136.53	$29,109	100.0%	75.5%
Total Day Ahead Load (GWh)	203,801			210,012			3.0%
Total Balancing Load (GWh)	(3,034)			(3,186)			5.0%
Total Real Time Load (GWh)	206,835			213,198			3.1%
Total Cost ($ Billions)	$16.09			$29.11			80.9%

61 Note: The totals in this table include after the fact billing adjustments and may not match totals presented in past reports.
62 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.
63 The MMU publishes monthly detail of the total cost of wholesale power. See <https://www.monitoringanalytics.com/data/pjm_cost.shtml>.

Figure 1-3 shows the total cost of wholesale power by category in the first three months of 2025 and 2026.

Figure 1-3 Total cost per MWh by category: January through March, 2025 and 2026

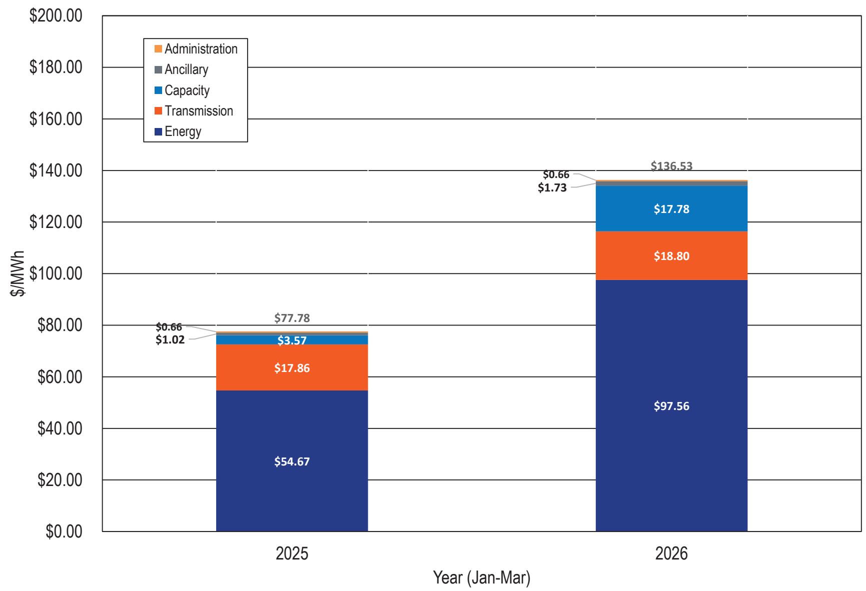


Figure 1-4 shows the contributions of the energy, capacity and transmission service components of the total cost of wholesale power for each quarter since 2001. In the third quarter of 2019, the cost of transmission per MWh of wholesale power exceeded the cost of capacity for the first time. In the third quarter of 2025, significant increases in capacity market prices resulted in the cost of capacity per MWh of wholesale power increasing above the cost of transmission. In the first quarter of 2026, total transmission costs per MWh again exceeded the cost of capacity per MWh.

Figure 1-4 Top three components of quarterly total cost ($/MWh): January 2001 through March 2026[64]

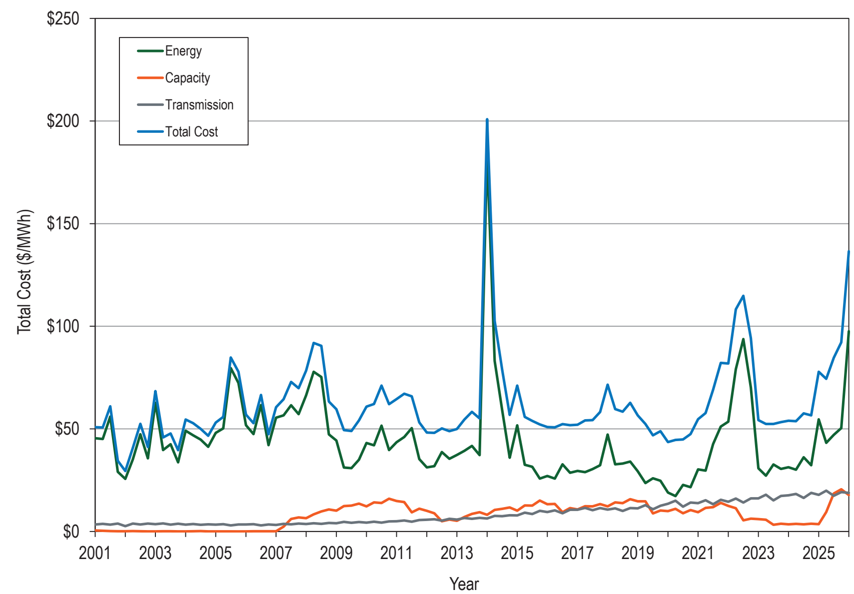


Table 1-11 shows the total cost, by component of the total wholesale power cost per MWh, for calendar years 2001 through 2025.

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

Table 1-10 Total cost per MWh by category: 2001 through 2025[65]

Category	2001 $/MWh	2002 $/MWh	2003 $/MWh	2004 $/MWh	2005 $/MWh	2006 $/MWh	2007 $/MWh	2008 $/MWh	2009 $/MWh	2010 $/MWh	2011 $/MWh	2012 $/MWh	2013 $/MWh	2014 $/MWh	2015 $/MWh	2016 $/MWh	2017 $/MWh	2018 $/MWh	2019 $/MWh	2020 $/MWh	2021 $/MWh	2022 $/MWh	2023 $/MWh	2024 $/MWh	2025 $/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	$48.91
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	$50.16
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	$1.02
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)	($1.94)
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)	($1.33)
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	$0.59
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	$0.01
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	($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	$0.03
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	$0.08
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	$0.94
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)	($0.73)
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	$0.11
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	$13.11
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	$12.94
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	$0.15
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	$0.02
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	$17.73	$18.53
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	$15.73
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	$2.59	$2.71
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	$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	$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	$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	$0.91	$1.10
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	$0.51	$0.48	$0.44
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	$0.38
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	$0.06
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	$0.19
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	$0.01
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	$0.02
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	$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	$0.67
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	$0.62
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	$0.05
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	$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	$0.00
Total Cost ($/MWh)	$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	$55.52	$82.33
Total Day Ahead Load (GWh)	292,717	344,235	324,653	413,294	654,505	672,501	691,547	676,030	644,485	656,928	704,581	745,165	753,865	749,927	773,842	774,730	760,624	784,553	771,055	734,641	755,824	765,499	748,619	775,838	800,515
Total Balancing Load (GWh)	27,319	31,337	(2,879)	(25,580)	(30,087)	(23,664)	(23,977)	(22,429)	(21,584)	(40,463)	(18,519)	(19,136)	(19,925)	(30,578)	(2,251)	(3,538)	1,849	(6,542)	(874)	(8,346)	(11,602)	(13,126)	(6,433)	(8,344)	(10,378)
Total Real Time Load (GWh)	265,398	312,899	327,533	438,874	684,592	696,165	715,524	698,459	666,069	697,391	723,101	764,300	773,790	780,505	776,093	778,269	758,775	791,094	771,929	742,987	767,425	778,624	755,053	784,182	810,894
Total Cost ($ 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	$66.76

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

Table 1-11 shows the percent of total cost, by component of the wholesale power cost per MWh, for calendar years 2001 through 2025.

Table 1-11 Percent of total cost per MWh by category: 2001 through 2025[66]

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	Percent of Total Charges 2025
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%	88.1%
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%	90.3%
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%	1.8%
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%)	(3.5%)
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%)	(2.4%)
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%	1.1%
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%	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%	(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%	0.1%
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%	0.1%
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%	1.7%
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%)	(1.3%)
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%	0.2%
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%	23.6%
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%	23.3%
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%	0.3%
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%	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%	33.4%
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%	28.3%
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%	4.7%	4.9%
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%	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%	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%	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%	1.6%	2.0%
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%	0.8%
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%	0.7%
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%	0.1%
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%	0.3%
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%	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%	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%	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%	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%	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%	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%	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%	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%	148.3%

66 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 inflation adjusted average cost, by component, for the first three months of 2025 and 2026. 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).[67]

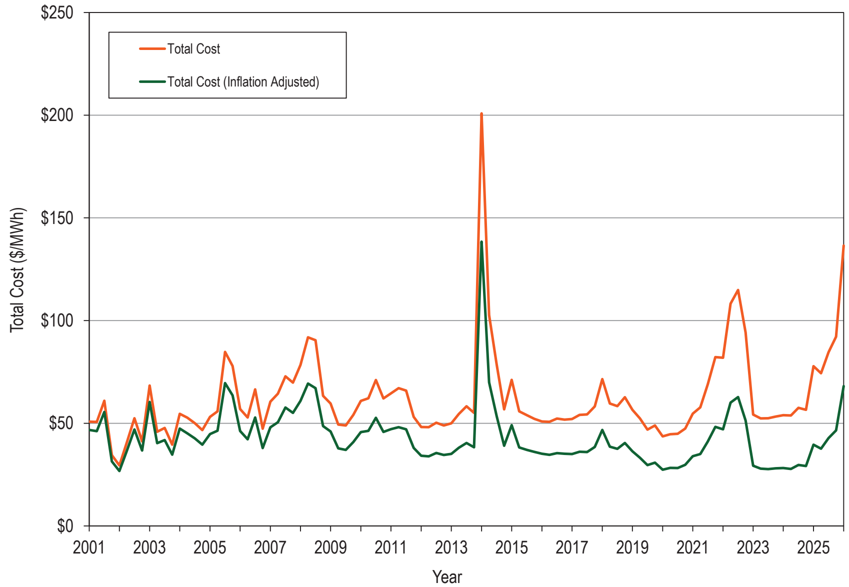
Table 1-12 Inflation adjusted total cost per MWh by category: January through March, 2025 and 2026[68 69 70]

Category	2025 (Jan-Mar) $/MWh	2025 (Jan-Mar) ($ Millions)	2025 (Jan-Mar)Percent of Total	2026 (Jan-Mar) $/MWh	2026 (Jan-Mar) ($ Millions)	2026 (Jan-Mar)Percent of Total	Percent Change
Energy	$27.73	$5,736	70.0%	$48.32	$10,302	71.0%	74.2%
Day Ahead Energy	$26.89	$5,561	67.9%	$47.07	$10,036	69.1%	75.1%
Balancing Energy	$0.56	$115	1.4%	$1.01	$214	1.5%	81.0%
ARR Credits	($0.59)	($123)	(1.5%)	($1.10)	($235)	(1.6%)	85.7%
Self Scheduled FTR Credits	($0.46)	($96)	(1.2%)	($0.93)	($198)	(1.4%)	100.2%
Balancing Congestion	$0.49	$102	1.2%	$0.50	$106	0.7%	0.7%
Emergency Energy	$0.00	$0	0.0%	$0.05	$10	0.1%	0.0%
Inadvertent Energy	($0.01)	($1)	(0.0%)	$0.02	$5	0.0%	(458.2%)
Load Response - Energy	$0.02	$3	0.0%	$0.04	$9	0.1%	165.2%
Emergency Load Response	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Energy Uplift (Operating Reserves)	$1.15	$239	2.9%	$2.29	$488	3.4%	98.4%
Marginal Loss Surplus Allocation	($0.38)	($79)	(1.0%)	($0.78)	($165)	(1.1%)	102.3%
Market to Market Payments	$0.08	$16	0.2%	$0.15	$33	0.2%	99.9%
Capacity	$1.95	$404	4.9%	$9.31	$1,986	13.7%	376.7%
Capacity (Capacity Market and FRR)	$1.89	$391	4.8%	$9.59	$2,045	14.1%	407.9%
Capacity Part V (RMR)	$0.07	$14	0.2%	($0.28)	($59)	(0.4%)	(523.0%)
Load Response - Capacity	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Transmission	$9.05	$1,872	22.9%	$9.28	$1,978	13.6%	2.5%
Transmission Service Charges	$7.66	$1,583	19.3%	$8.01	$1,708	11.8%	4.7%
Transmission Enhancement Cost Recovery	$1.35	$279	3.4%	$1.22	$261	1.8%	(9.3%)
Transmission Owner (Schedule 1A)	$0.05	$10	0.1%	$0.04	$10	0.1%	(5.6%)
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	$0.52	$107	1.3%	$0.85	$182	1.3%	64.7%
Reactive	$0.23	$47	0.6%	$0.20	$42	0.3%	(12.2%)
Regulation	$0.16	$34	0.4%	$0.50	$107	0.7%	206.4%
Black Start	$0.04	$8	0.1%	$0.03	$6	0.0%	(33.3%)
Synchronized Reserves	$0.08	$17	0.2%	$0.11	$23	0.2%	37.5%
Secondary Reserves	$0.00	$0	0.0%	$0.01	$2	0.0%	743.7%
Non-Synchronized Reserves	$0.01	$2	0.0%	$0.01	$1	0.0%	(31.6%)
Day Ahead Scheduling Reserve (DASR)	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Administration	$0.34	$69	0.8%	$0.33	$70	0.5%	(2.5%)
PJM Administrative Fees	$0.31	$64	0.8%	$0.30	$65	0.4%	(2.8%)
NERC/RFC	$0.02	$4	0.1%	$0.02	$5	0.0%	3.5%
RTO Startup and Expansion	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Other	$0.00	$0	0.0%	$0.00	$0	0.0%	(9.7%)
Total Cost ($/MWh)	$39.59	$8,189	100.0%	$68.09	$14,518	100.0%	72.0%
Total Day Ahead Load (GWh)	203,801			210,012			3.0%
Total Balancing Load (GWh)	(3,034)			(3,186)			5.0%
Total Real Time Load (GWh)	206,835			213,198			3.1%
Total Cost ($ Billions)	$8.19			$14.52			77.3%

67 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, 2026).
68 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.
69 Note: The totals in this table include after the fact billing adjustments and may not match totals presented in past reports.
70 Note: The U.S. Bureau of Labor Statistics did not publish CPI data for October 2025. October 2025 CPI data was approximated using the geometric mean of September and November 2025 index values. Further information on approximating BLS data for missing data points can be found at: https://www.bls.gov/cpi/factsheets/approximating-missing-data.htm.

Figure 1-5 shows the total price of wholesale power and the inflation adjusted total price of wholesale power for each quarter since 2001.[71]

Figure 1-5 Quarterly total cost and quarterly inflation adjusted total cost ($/MWh): January 2001 through March 2026[72]



71 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, 2026).
72 Note: The totals presented in this figure include after the fact billing adjustments and may not match totals presented in past reports.

Table 1-13 shows the inflation adjusted total cost, by component of the total wholesale power cost per MWh, for calendar years 2001 through 2025.[73]

Table 1-13 Inflation adjusted total cost per MWh by category: 2001 through 2025[74]

Category	2001 $/MWh	2002 $/MWh	2003 $/MWh	2004 $/MWh	2005 $/MWh	2006 $/MWh	2007 $/MWh	2008 $/MWh	2009 $/MWh	2010 $/MWh	2011 $/MWh	2012 $/MWh	2013 $/MWh	2014 $/MWh	2015 $/MWh	2016 $/MWh	2017 $/MWh	2018 $/MWh	2019 $/MWh	2020 $/MWh	2021 $/MWh	2022 $/MWh	2023 $/MWh	2024 $/MWh	2025 $/MWh
Energy	$40.54	$33.10	$39.54	$38.43	$52.73	$40.97	$45.02	$50.06	$26.76	$32.88	$31.66	$24.24	$27.01	$63.81	$24.56	$19.35	$19.97	$23.74	$16.44	$12.64	$22.84	$41.00	$16.12	$16.79	$24.55
Day Ahead Energy	$36.20	$31.70	$36.68	$34.84	$49.69	$40.06	$44.46	$51.37	$28.50	$33.50	$31.83	$23.71	$26.27	$35.47	$24.94	$19.85	$20.39	$24.21	$17.17	$13.16	$22.97	$40.90	$16.75	$17.23	$25.17
Balancing Energy	$4.07	$2.01	$3.07	$3.47	$3.18	$2.00	$2.37	$2.61	$1.36	$2.64	$1.48	$1.09	$1.27	$28.93	$0.55	$0.36	$0.23	$0.47	$0.11	$0.22	$0.48	$1.12	$0.24	$0.29	$0.51
ARR Credits	$0.00	$0.00	($0.24)	($0.34)	($0.32)	($0.47)	($0.49)	($0.54)	($0.67)	($0.39)	($0.46)	($0.39)	($0.31)	($0.37)	($0.50)	($0.55)	($0.45)	($0.45)	($0.55)	($0.43)	($0.33)	($0.63)	($0.78)	($0.64)	($0.97)
Self Scheduled FTR Credits	($0.85)	($1.21)	($0.73)	($0.28)	($0.66)	($0.97)	($1.23)	($1.63)	($0.52)	($0.93)	($0.41)	($0.16)	($0.16)	($0.43)	($0.31)	($0.20)	($0.13)	($0.22)	($0.09)	($0.12)	($0.20)	($0.61)	($0.22)	($0.27)	($0.67)
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	$0.02	$0.06	$0.11	$0.11	$0.18	$0.37	$0.21	$0.20	$0.30
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	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.00	$0.00	$0.00
Inadvertent Energy	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	($0.00)	($0.01)	$0.00	($0.01)	$0.03	$0.01	($0.01)	($0.00)	$0.00	($0.01)	$0.01	$0.00	($0.00)	$0.00	$0.00	($0.01)	$0.00	$0.01	($0.01)
Load Response - Energy	$0.00	$0.00	$0.00	$0.00	$0.00	$0.02	$0.05	$0.03	$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	$0.00	$0.01	$0.02
Emergency Load Response	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.01	$0.01	$0.04	$0.04	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.04	$0.00	$0.04
Energy Uplift (Operating Reserves)	$1.15	$0.65	$0.78	$0.81	$0.88	$0.38	$0.51	$0.48	$0.36	$0.59	$0.56	$0.52	$0.38	$0.77	$0.26	$0.12	$0.09	$0.15	$0.07	$0.08	$0.14	$0.20	$0.11	$0.18	$0.48
Marginal Loss Surplus Allocation	($0.04)	($0.04)	($0.05)	($0.07)	($0.09)	($0.05)	($0.66)	($2.30)	($2.31)	($2.57)	($1.46)	($0.60)	($0.51)	($0.64)	($0.43)	($0.25)	($0.23)	($0.57)	($0.41)	($0.42)	($0.42)	($0.48)	($0.27)	($0.23)	($0.37)
Market to Market Payments	$0.00	$0.00	$0.00	$0.00	$0.02	($0.00)	$0.01	$0.04	$0.04	$0.04	$0.07	$0.04	$0.02	$0.04	$0.04	$0.03	$0.04	$0.08	$0.03	$0.04	$0.02	$0.13	$0.04	$0.03	$0.05
Capacity	$0.24	$0.11	$0.07	$0.08	$0.03	$0.08	$3.67	$7.41	$9.58	$10.55	$8.81	$5.33	$5.44	$7.15	$8.86	$8.41	$8.37	$9.18	$7.73	$6.49	$7.30	$5.13	$2.54	$1.97	$6.96
Capacity (Capacity Market and FRR)	$0.24	$0.11	$0.07	$0.08	$0.02	$0.02	$3.63	$7.38	$9.57	$10.54	$8.72	$5.27	$5.40	$7.13	$8.86	$8.41	$8.34	$9.15	$7.71	$6.49	$7.30	$5.09	$2.48	$1.95	$6.87
Capacity Part V (RMR)	$0.00	$0.00	$0.00	$0.00	$0.01	$0.06	$0.04	$0.03	$0.01	$0.01	$0.09	$0.06	$0.04	$0.03	($0.00)	($0.00)	$0.02	$0.03	$0.01	$0.00	$0.00	$0.04	$0.06	$0.02	$0.08
Load Response - Capacity	$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	$0.01	$0.01
Transmission	$3.25	$3.10	$3.20	$2.93	$2.73	$2.68	$2.76	$2.89	$3.29	$3.36	$3.70	$4.06	$4.36	$4.98	$6.01	$6.56	$7.20	$6.97	$7.45	$8.48	$8.57	$8.35	$8.77	$9.13	$9.29
Transmission Service Charges	$3.18	$3.04	$3.14	$2.80	$2.24	$2.55	$2.69	$2.76	$3.04	$2.99	$3.23	$3.45	$3.61	$4.07	$4.84	$5.26	$5.82	$5.67	$6.19	$7.08	$7.15	$7.05	$7.49	$7.75	$7.89
Transmission Enhancement Cost Recovery	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.05	$0.18	$0.30	$0.40	$0.55	$0.69	$0.85	$1.10	$1.25	$1.33	$1.24	$1.20	$1.35	$1.36	$1.26	$1.23	$1.33	$1.36
Transmission Owner (Schedule 1A)	$0.07	$0.06	$0.06	$0.08	$0.07	$0.07	$0.07	$0.07	$0.06	$0.07	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06	$0.05	$0.04	$0.04	$0.05	$0.05
Transmission Seams Elimination Cost Assignment (SECA)	$0.00	$0.00	$0.00	$0.04	$0.41	$0.06	$0.00	$0.00	$0.00	$0.00	($0.00)	$0.00	$0.00	$0.00	$0.00	$0.00	($0.02)	$0.00	$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	$0.00	$0.00	$0.01	($0.01)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Ancillary	$0.68	$0.56	$0.80	$0.77	$0.98	$0.74	$0.78	$0.86	$0.59	$0.66	$0.64	$0.59	$0.86	$0.67	$0.62	$0.48	$0.50	$0.51	$0.45	$0.45	$0.51	$0.59	$0.47	$0.47	$0.55
Reactive	$0.20	$0.18	$0.21	$0.22	$0.21	$0.23	$0.23	$0.25	$0.27	$0.33	$0.29	$0.32	$0.53	$0.27	$0.25	$0.26	$0.28	$0.26	$0.27	$0.29	$0.28	$0.27	$0.27	$0.25	$0.22
Regulation	$0.48	$0.38	$0.44	$0.43	$0.66	$0.42	$0.49	$0.52	$0.26	$0.27	$0.23	$0.18	$0.17	$0.22	$0.16	$0.07	$0.09	$0.12	$0.07	$0.06	$0.11	$0.21	$0.09	$0.12	$0.19
Black Start	$0.00	$0.00	$0.01	$0.01	$0.02	$0.02	$0.02	$0.02	$0.02	$0.01	$0.01	$0.02	$0.10	$0.05	$0.05	$0.06	$0.06	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.03
Synchronized Reserves	$0.00	$0.01	$0.13	$0.11	$0.09	$0.07	$0.05	$0.06	$0.04	$0.05	$0.07	$0.03	$0.03	$0.08	$0.08	$0.04	$0.04	$0.04	$0.03	$0.02	$0.04	$0.06	$0.05	$0.05	$0.09
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	$0.01
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	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	($0.01)	$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	$0.04	$0.03	$0.04	$0.03	$0.07	$0.05	$0.03	$0.03	$0.01	$0.01	$0.01	$0.01	$0.00	$0.00	$0.00
Administration	$0.68	$0.77	$0.95	$0.91	$0.63	$0.65	$0.64	$0.36	$0.27	$0.32	$0.29	$0.35	$0.30	$0.32	$0.32	$0.32	$0.35	$0.39	$0.39	$0.34	$0.33	$0.30	$0.33	$0.35	$0.34
PJM Administrative Fees	$0.67	$0.77	$0.92	$0.80	$0.60	$0.60	$0.59	$0.32	$0.24	$0.27	$0.27	$0.33	$0.28	$0.29	$0.29	$0.30	$0.32	$0.37	$0.36	$0.31	$0.30	$0.28	$0.30	$0.32	$0.31
NERC/RFC	$0.01	$0.01	$0.04	$0.06	$0.03	$0.04	$0.04	$0.03	$0.01	$0.02	$0.01	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02
RTO Startup and Expansion	$0.00	$0.00	$0.00	$0.05	$0.00	$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	$0.00	$0.00
Other	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.01	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00
Total Cost ($/MWh)	$45.40	$37.66	$44.57	$43.12	$57.11	$45.12	$52.87	$61.57	$40.48	$47.78	$45.10	$34.57	$37.98	$76.95	$40.36	$35.12	$36.38	$40.80	$32.45	$28.40	$39.56	$55.37	$28.23	$28.72	$41.69
Total Day Ahead Load (GWh)	292,717	344,235	324,653	413,294	654,505	672,501	691,547	676,030	644,485	656,928	704,581	745,165	753,865	749,927	773,842	774,730	760,624	784,553	771,055	734,641	755,824	765,499	748,619	775,838	800,515
Total Balancing Load (GWh)	27,319	31,337	(2,879)	(25,580)	(30,087)	(23,664)	(23,977)	(22,429)	(21,584)	(40,463)	(18,519)	(19,136)	(19,925)	(30,578)	(2,251)	(3,538)	1,849	(6,542)	(874)	(8,346)	(11,602)	(13,126)	(6,433)	(8,344)	(10,378)
Total Real Time Load (GWh)	265,398	312,899	327,533	438,874	684,592	696,165	715,524	698,459	666,069	697,391	723,101	764,300	773,790	780,505	776,093	778,269	758,775	791,094	771,929	742,987	767,425	778,624	755,053	784,182	810,894
Total Cost ($ Billions)	$12.05	$11.78	$14.60	$18.93	$39.10	$31.41	$37.83	$43.01	$26.96	$33.32	$32.61	$26.42	$29.39	$60.06	$31.32	$27.33	$27.61	$32.27	$25.05	$21.10	$30.36	$43.11	$21.32	$22.52	$33.81

73 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, 2026).
74 Note: The totals in this table include after the fact billing adjustments and may not match totals presented in past reports.

Table 1-14 shows the percent of the inflation adjusted total cost, by component of the wholesale power cost per MWh, for calendar years 2001 through 2025. [75]

Table 1-14 Inflation adjusted percent of total cost per MWh by category: 2001 through 2025[76]

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	Percent of Total Charges 2025
Energy	89.3%	87.9%	88.7%	89.1%	92.3%	90.8%	85.1%	81.3%	66.1%	68.8%	70.2%	70.1%	71.1%	82.9%	60.8%	55.1%	54.9%	58.2%	50.6%	44.5%	57.7%	74.0%	57.1%	58.5%	85.5%
Day Ahead Energy	79.7%	84.2%	82.3%	80.8%	87.0%	88.8%	84.1%	83.4%	70.4%	70.1%	70.6%	68.6%	69.2%	46.1%	61.8%	56.5%	56.0%	59.3%	52.9%	46.3%	58.1%	73.9%	59.3%	60.0%	87.6%
Balancing Energy	9.0%	5.3%	6.9%	8.1%	5.6%	4.4%	4.5%	4.2%	3.4%	5.5%	3.3%	3.1%	3.3%	37.6%	1.4%	1.0%	0.6%	1.2%	0.3%	0.8%	1.2%	2.0%	0.8%	1.0%	1.8%
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%)	(1.2%)	(1.6%)	(1.2%)	(1.1%)	(1.7%)	(1.5%)	(0.8%)	(1.1%)	(2.7%)	(2.2%)	(3.4%)
Self Scheduled FTR Credits	(1.9%)	(3.2%)	(1.6%)	(0.6%)	(1.2%)	(2.1%)	(2.3%)	(2.6%)	(1.3%)	(1.9%)	(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%)	(2.3%)
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%	1.0%
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%	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%	(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%	0.1%
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%	0.1%
Energy Uplift (Operating Reserves)	2.5%	1.7%	1.7%	1.9%	1.5%	0.8%	1.0%	0.8%	0.9%	1.2%	1.2%	1.5%	1.0%	1.0%	0.6%	0.3%	0.3%	0.4%	0.2%	0.3%	0.3%	0.4%	0.4%	0.6%	1.7%
Marginal Loss Surplus Allocation	(0.1%)	(0.1%)	(0.1%)	(0.2%)	(0.2%)	(0.1%)	(1.3%)	(3.7%)	(5.7%)	(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%)	(1.3%)
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%	0.2%
Capacity	0.5%	0.3%	0.2%	0.2%	0.1%	0.2%	6.9%	12.0%	23.7%	22.1%	19.5%	15.4%	14.3%	9.3%	22.0%	23.9%	23.0%	22.5%	23.8%	22.8%	18.5%	9.3%	9.0%	6.9%	24.2%
Capacity (Capacity Market and FRR)	0.5%	0.3%	0.2%	0.2%	0.0%	0.0%	6.9%	12.0%	23.7%	22.1%	19.3%	15.2%	14.2%	9.3%	21.9%	23.9%	22.9%	22.4%	23.8%	22.8%	18.5%	9.2%	8.8%	6.8%	23.9%
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%	0.3%
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%	0.0%
Transmission	7.2%	8.2%	7.2%	6.8%	4.8%	5.9%	5.2%	4.7%	8.1%	7.0%	8.2%	11.7%	11.5%	6.5%	14.9%	18.7%	19.8%	17.1%	23.0%	29.9%	21.7%	15.1%	31.1%	31.8%	32.4%
Transmission Service Charges	7.0%	8.1%	7.0%	6.5%	3.9%	5.7%	5.1%	4.5%	7.5%	6.3%	7.2%	10.0%	9.5%	5.3%	12.0%	15.0%	16.0%	13.9%	19.1%	24.9%	18.1%	12.7%	26.5%	27.0%	27.5%
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%	2.7%	3.6%	3.7%	3.0%	3.7%	4.7%	3.5%	2.3%	4.4%	4.6%	4.7%
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%	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%	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%	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%	1.5%	1.4%	1.4%	1.3%	1.4%	1.6%	1.3%	1.1%	1.7%	1.6%	1.9%
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%	0.8%
Regulation	1.1%	1.0%	1.0%	1.0%	1.1%	0.9%	0.9%	0.8%	0.6%	0.6%	0.5%	0.5%	0.5%	0.3%	0.4%	0.2%	0.2%	0.3%	0.2%	0.2%	0.3%	0.4%	0.3%	0.4%	0.7%
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%	0.1%
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%	0.3%
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%	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%	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%	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%	1.2%
PJM Administrative Fees	1.5%	2.0%	2.1%	1.8%	1.1%	1.3%	1.1%	0.5%	0.6%	0.6%	0.6%	0.9%	0.7%	0.4%	0.7%	0.8%	0.9%	0.9%	1.1%	1.1%	0.8%	0.5%	1.1%	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%	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%	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%	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%	145.2%

75 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, 2026).
76 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 2026, 593 MW of new resources were added in the energy market, and 2 MW of resources were retired.
- The real-time hourly on peak average offered supply in the first three months of 2026 decreased by 2.8 percent, from the first three months of 2025, from 146,532 MWh to 142,490 MWh.
- The day-ahead hourly average offered supply in the first three months of 2026 decreased by 3.4 percent, from the first three months of 2025, from 159,428 MWh to 154,058 MWh.
- The real-time hourly average cleared generation in the first three months of 2026 increased by 1.8 percent from the first three months of 2025, from 102,126 MWh to 103,976 MWh.
- The day-ahead hourly average cleared supply in the first three months of 2026, including INCs and UTCs, decreased by 0.2 percent from the first three months of 2025 from 116,697 MWh to 116,436 MWh.
- **Demand.** The real-time hourly peak load without exports in the first three months of 2026 was 135,722 MWh (137,037 MWh with net exports) in the HE 0800 (EPT) on January 29, 2026, lower than the PJM peak load in the first three months of 2025, which was 140,043 MWh (147,704 MWh with net exports) in the HE 0900 (EPT) on January 22, 2025.
- The real-time hourly average load in the first three months of 2026 increased by 3.1 percent from the first three months of 2025, from 95,801 MWh to 98,749 MWh.
- The day-ahead hourly average cleared demand in the first three months of 2026, including DECs and UTCs, increased by 2.2 percent from the first three months of 2025, from 102,310 MWh to 104,565 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 decreased by 8.5 percent and the cleared increment MW decreased by 14.0 percent in the first three months of 2026 compared to the first three months of 2025. The hourly average submitted decrement bid MW increased by 2.5 percent and the cleared decrement MW increased by 1.9 percent in the first three months of 2026 compared to the first three months of 2025. The hourly average submitted up to congestion bid MW decreased by 20.7 percent and the cleared up to congestion bid MW decreased by 25.8 percent in the first three months of 2026 compared to the first three months of 2025.

Market Performance

- **Generation Fuel Mix.** In the first three months of 2026, generation from coal units decreased 1.7 percent, generation from natural gas units increased 4.2 percent, generation from oil units increased 43.2 percent, generation from wind units decreased 4.7 percent, and generation from solar units increased 15.0 percent compared to the first three months of 2025.
- **Fuel Diversity.** The fuel diversity of energy generation in the first three months of 2026, measured by the fuel diversity index for energy (FDI_e), decreased 0.6 percent compared to the first three months of 2025.
- **Marginal Resources.** In the PJM Real-Time Energy Market in the first three months of 2026, coal units were 9.6 percent, natural gas units were 65.9 percent and wind units were 20.2 percent of marginal resources. In the first three months of 2025, coal units were 8.1 percent, natural gas units were 71.1 and wind units were 15.8 percent of marginal resources.
- **Prices.** The real-time load-weighted average LMP in the first three months of 2026 increased $35.37 per MWh, or 67.8 percent, from the first three months of 2025, from $52.20 per MWh to $87.57 per MWh.

- The day-ahead load-weighted average LMP in the first three months of 2026 increased $41.70 per MWh, or 77.8 percent, from the first three months of 2025, from $53.60 per MWh to $95.30 per MWh.
- **Fast Start Pricing**. The real-time load-weighted average PLMP was $87.57 per MWh for the first three months of 2026, which is 8.0 percent, $6.48 per MWh, higher than the real-time load-weighted average DLMP of $81.08 per MWh.
- **Components of Real-Time LMP.** In the PJM Real-Time Energy Market in the first three months of 2026, 47.0 percent of the real-time load-weighted LMP was the result of gas costs, 15.7 percent was the result of transmission constraint violation penalty factors, 5.2 percent was the result of coal costs, and 2.3 percent was the result of the cost of emission allowances.
- **Components of Day-Ahead LMP.** In the PJM Day-Ahead Energy Market in the first three months of 2026, 25.4 percent of the day-ahead load-weighted LMP was the result of decrement bids, 13.7 percent was the result of increment offers, 25.2 percent was the result of gas costs, and 6.0 percent was the result of coal costs.
- **Changes in Real-Time LMP.** Of the $35.37 per MWh increase in the real-time load-weighted average LMP, $14.92 per MWh (42.2 percent) was the fuel and consumables cost components of LMP, $9.73 per MWh (27.5 percent) was the transmission constraint penalty factor component of LMP, $3.56 per MWh (10.1 percent) was the sum of the markup, maintenance, and ten percent adder components of LMP, $1.26 per MWh (3.6 percent) was the emissions cost components of LMP, and $0.85 per MWh (2.4 percent) was the scarcity component of LMP. The pre-emergency demand response called on by PJM during Winter Storm Fern increased LMP by $0.18 per MWh, 0.5 percent of the increase in LMP. The LMP increase would have been higher if PJM had not imposed a $3,700.00 per MWh administrative cap. The administrative cap reduced the LMP by $0.03 per MWh, a 0.1 percent decrease.
- **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 $6.62 per MWh in the first three months of 2026, and $1.10 per MWh in the first three months of 2025. The larger difference in the first three months of 2026 resulted from conservative operations during Winter Storm Fern when conservatively committed supply did not clear the day-ahead market but operated in the real-time market. 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 86 intervals with five minute shortage pricing on 17 days in the first three months of 2026. Of the 86 intervals, 40 occurred during cold weather from late January into early February, including Winter Storm Fern, for which PJM issued several emergency warnings and actions. Three of the 86 intervals of shortage overlapped with synchronized reserve events.
- **SCED Shortage Intervals.** In the first three months of 2026, there were 1,445 five minute intervals, or 5.6 percent of all five minute intervals, for which at least one RT SCED solution showed a shortage of reserves. In the first three months of 2026, there were 486 five minute intervals, or 1.9 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 2026, PJM triggered shortage pricing for 86 five minute intervals, or 6.0 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 81 days, 90.0 percent of the days, in the first three months of 2026 and 79 days, 87.8 percent of the days, in the first three months of 2025. The overall frequency of pivotal suppliers rose in 2025 and the first three months of 2026 due to an increase in the frequency of days with daily peak load above 130 GW.

- **Local Market Power.** In 2025, in the real-time market, the 500 kV system, 13 zones, and the PJM/MISO interface experienced congestion resulting from one or more constraints binding for 100 or more hours. For eight out of the top 10 congested facilities (by real-time binding hours) in the first three months of 2026, 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 2.1 percent in the first three months of 2025 to 3.4 percent in the first three months of 2026. In the real-time energy market, for units committed to provide energy for local constraint relief, offer-capped unit hours increased from 1.4 percent in the first three months of 2025 to 1.7 percent in the first three months of 2026. 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 promptly.

- **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 zero percent in the first three months of 2025 to 0.02 percent in the first three months of 2026. In the real-time energy market, for units committed for reliability reasons, offer-capped unit hours decreased from 0.13 percent in the first three months of 2025 to 0.01 percent in the first three months of 2026. 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 committed on their least cost schedule as defined in the day-ahead and real-time markets.

- **Parameter Mitigation.** PJM applies operating parameter limits (PLS) to units that fail the TPS test and to all units during hot and cold weather alerts. In the first three months of 2026, 26.2 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, 25.6 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. These units should be committed on their parameter limited schedules to resolve the market power issue. If PJM promptly implemented the FERC approved solution to address the failure to correctly apply market power mitigation, this issue would no longer occur.

- **Frequently Mitigated Units (FMU) and Associated Units (AU).** In the first three months of 2026, no units qualified for an FMU adder. In 2025, 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 -$0.03 when using unadjusted cost-based offers in the first three months of 2026, 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 2026 was more than $900 per MWh and the highest markup 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 $1.48 per MWh in the first three months of 2026, 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 2026 was more than $600 per MWh.[77]

- **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 2026, the unadjusted markup component (net of positive and negative markup components) of LMP was $0.56 per MWh or 0.6 percent of the PJM load-weighted average LMP. February had the highest unadjusted peak markup component, $4.16 per MWh, or 5.2 percent of the real-time peak hour load-weighted average LMP for February.

  In the PJM Day-Ahead Energy Market in the first three months of 2026, the unadjusted markup component (net of positive and negative markup components) of LMP was $1.38 per MWh or 1.4 percent of the PJM load-weighted average LMP. January had the highest unadjusted peak markup component, $5.37 per MWh, or 3.30 percent of the day-ahead peak hour load-weighted average LMP for January.

  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 noncompetitive economic withholding.

- **Markup and Local Market Power.** Comparison of the markup behavior of marginal units with TPS test results shows that for 2.4 percent of all real-time marginal unit intervals in the first three months of 2026, the marginal unit had both local market power, as determined by the TPS test, and a positive markup. The marginal unit had local market power in 20.4 percent of all real-time marginal unit intervals in the first three months of 2026. For 12.0 percent of all marginal unit intervals with local market power, the unit had a positive markup. This occurred in 752 intervals, or 2.9 percent of all real-time market intervals in the first three months of 2026. 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 2026, 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 for 296 marginal unit intervals and 40 day-ahead marginal unit hours. 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.

77 MMU identified an error in the PJM marginal resource identification algorithm within the day ahead clearing optimization. The calculation of generator sensitivity factors requires accurate identification of marginal resources. The error was fixed by the PJM software vendor in March 2025. MMU was unable to calculate the component breakdown for 2024 and the first quarter of 2025 due to the inaccurate identification of marginal resources.

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, including parameter limited schedules. 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 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 maintenance costs from the Cost Development Guidelines. (Priority: Medium. First reported 2019. Status: Not adopted.)
- 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.)[78]
- 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.)
- 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.)[79]

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 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.)

78 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.

79 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.

- 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.)

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.)[80]
- 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.)

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

80 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.

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.)[81]

- 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.[82] (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.[83] [84] (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

81 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.

82 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: Energy Market at 114 – 116.

83 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.

84 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>.

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, 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.)[85]
- 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.)[86]

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.)

Section 3 Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in the first three months of 2026, 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 2026, LMP increased by $35.37 per MWh compared to the first three months of 2025, or 67.8 percent. The fuel cost components of LMP (the sum of gas, coal, oil, landfill gas, and consumables) increased $14.92 per MWh, 42.2 percent of the increase in LMP. The transmission constraint penalty factor component increased by $9.73 per MWh, 27.5 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 pre-emergency demand response called on by PJM during Winter Storm Fern increased LMP by $0.18 per MWh, 0.5 percent of the increase in LMP. The emissions cost components of LMP, including opportunity costs for emissions limited resources, increased by $1.26 per MWh, 3.6 percent of the increase in LMP. The opportunity costs for emissions alone increased by $1.56 per MWh, 4.4 percent of the increase in LMP. The LMP increase would have been higher if PJM had not imposed a $3,700.00 per MWh administrative cap.

85 Fuel type is reported by offer schedule, but it can be inaccurate on an hourly basis.
86 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.

The administrative cap reduced the LMP by $0.03 per MWh, a 0.1 percent decrease.

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 2026 generally reflected supply-demand fundamentals, although the behavior of some participants both routinely and during high demand periods represents noncompetitive economic withholding. Economic withholding occurs when generator offers are greater than competitive levels. In the first three months of 2026, the sum of the markup, ten percent adder, and maintenance cost (not short run marginal cost) components increased by $3.56 per MWh or 10.1 percent of the increase in LMP. In the first three months of 2026, PJM actions, in the form of transmission constraint penalty factors, significantly increased prices. In the first three months of 2026, the transmission constraint penalty factor component increased by $9.73 per MWh, 27.5 percent of the increase in LMP.

Data center load growth affects energy market prices. Increased demand without matching energy supply puts upward pressure on prices, all else equal. It is difficult to shield customers from the costs caused by data center load growth in the energy market. The impact on the energy market is greater when data centers are added with adding corresponding generating capacity and its associated energy output.

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.[87] The transmission constraint penalty factors are currently the second largest determinant of LMP after the marginal cost of gas. PJM has not experienced a prolonged load shedding event, but, if one were to occur, LMP could exceed $3,700 per MWh for the entire event.

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 implemented to increase generators' revenue is not consistent with a competitive market design. Changes in the market, like data center load growth and renewable energy growth, do not imply that PJM's current shortage pricing levels are too low. Artificially increasing energy market prices through market design changes is not a solution for managing either data center load growth or renewable energy growth.

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, that scarcity pricing recognize that electric power serves a unique and critical role for customers, 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 in SCED, transmission constraint penalty factors, load forecast bias, hydro resource schedules, fast start pricing, and the treatment of demand resources 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. The transmission constraint penalty factor contribution to the load-weighted average LMP in the first three months of 2026 was $13.76 per MWh or $2.93 billion of the total $18.6 billion cost of real-time load. In the first three months of 2026, the transmission constraint penalty factor contribution to the cost of real time load was nearly three times

87 177 FERC ¶ 61,209 (2021).

higher than the $979.8 million collected for energy uplift charges. In the first three months of 2026, the control limit used in RT SCED for 94 percent of violated transmission constraint intervals was less than 100 percent of the actual line limit, with an average reduction of 5.5 percent. If the control limits had not been artificially reduced for PJM transmission constraints and everything else remained unchanged, the transmission constraint penalty factor's contribution to the load weighted average LMP in first three months of 2026 would have decreased by 99.4 percent from $13.76 to $0.08 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, 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. In the first three months of 2026, the pricing run LMP exceeded the dispatch run LMP by $6.48 per MWh in the real-time market. The large difference resulted from high fuel costs during Winter Storm Fern. The fuel costs included in the no load offer for fast start CTs were added to the LMP in the pricing run, creating the majority of the difference. 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.[88] 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 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.

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

The question of how to provide market incentives for investment in flexibility, and for operating to the full capability of that flexibility should be addressed directly. Are units inflexible because they are old and inefficient, because they face gas pipeline constraints, 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?

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

88 See 173 FERC ¶ 61,244 (2020).

The relationship between supply and demand is referred to as supply-demand fundamentals, or economic fundamentals, or market structure. The market structure of the PJM aggregate energy market is only 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 at all times. This assumption requires that the total demand for energy can be met without the supply from any individual supplier or from a small group of suppliers. This assumption is not correct. There are pivotal suppliers in the aggregate energy market with increasing frequency as daily peak loads increase. The frequency of days with aggregate pivotal suppliers was 90.0 percent in the first three months of 2026, compared to 87.8 percent in the first three months of 2025. High markups for some units demonstrate the potential to exercise market power both routinely and during high demand conditions. In the first three months of 2026, 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 for 296, or 0.4 percent of, marginal unit intervals. 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.[89] 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.[90] [91] Many of these issues can be resolved by simple rule changes. PJM filed and, on October 25, 2024, FERC accepted a proposal that requires that sellers that fail the TPS test be offer capped at their cost-based offers and that operating parameters will be mitigated.[92] 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 a software improvement, with no defined date. The flawed rules remain in place. There is no reason to delay implementation of the FERC approved rules until PJM addresses combined cycle modelling. The changes would decrease the solution time for the day-ahead market and enhance market efficiency. The approved approach 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

89 The MMU reviews PJM's application of the TPS test and brings issues to the attention of PJM.

90 See 175 FERC ¶ 61,231 (2021).
91 185 FERC ¶ 61,158 (2023).
92 189 FERC ¶ 61,060 (2024).

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 first three months of 2026 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 results in the exercise of market power 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 for implementing an aggregate market power test and correcting the offer capping process for resources with local market power. In addition, PJM's extensive administrative interventions in the energy market should be reduced. The MMU concludes that the PJM energy market results were competitive in the first three months of 2026.

Overview: Section 4, Energy Uplift

Energy Uplift Credits

- **Energy uplift credits.** Total energy uplift credits increased by $509.5 million, or 108.4 percent, during the first three months of 2026 compared to the first three months of 2025, from $470.2 million to $979.7 million.
- **Types of energy uplift credits.** During the first three months of 2026, total energy uplift credits included $210.7 million in day-ahead generator credits, $649.6 million in balancing generator credits, $118.9 million in lost opportunity cost credits. Dispatch differential lost opportunity credits were $0.3 million during the first three months of 2026.
- **Types of units.** During the first three months of 2026, non-coal steam units received 96.4 percent of the day-ahead generator credits and steam coal units received 0.5 percent of day-ahead generator credits. Combustion turbines received 1.5 percent of balancing generator credits and 12.9 percent of lost opportunity cost credits. Combined cycle plants and combustion turbines received 62.6 percent of dispatch differential lost opportunity credits, and hydro units received 3.3 percent of dispatch differential lost opportunity credits
- **Concentration of energy uplift credits.** In the first three months of 2026, the top 10 units receiving energy uplift credits received 38.2 percent of all credits and the top 10 organizations received 78.9 percent of all credits.
- **Lost opportunity cost credits.** Lost opportunity cost credits increased by $109.3 million, from $9.6 million to $118.9 million, or 1,135.0 percent, during the first three months of 2026 compared to the first three months of 2025.

  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 75.4 percent of the $118.9 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.** During the first three months of 2026, total energy uplift charges increased by $509.0 million, or 108.1 percent, compared to the first three months of 2025, from $470.7 million to $979.8 million.
- **Types of Energy Uplift Charges.** During the first three months of 2026, total uplift charges included $210.7 million in day-ahead operating reserve charges, $768.4 million in balancing generator charges, $0.1 million in reactive charges, and $0.2 million in black start services, and $0.4 million in local congestion charges.

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 for energy produced because of not following dispatch. (Priority: Medium. First reported 2018. Status: Not adopted.)[93]
- The MMU recommends that PJM pay uplift based on the offer at the lower of the actual unit output or the desired MW. (Priority: Medium. First reported 2018. Status: Not adopted.)[94]
- 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.)
- 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.)
- The MMU recommends including real-time exports and real-time wheels in the allocation of the cost of providing reactive support to the 500

93 PJM filed proposed changes to the uplift rules with the FERC on October 7, 2025 ("Reform to Energy Uplift Credit Rules," Docket No. ER26-59-000). The Commission Order on December 5, 2025, accepted the PJM Proposal as filed. PJM expects to implement the changes in 2027.

94 Id.

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.)[95]

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 for 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

95 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).

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 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 fast start pricing.[96] 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.[97] 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.

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.

The MMU has recommended that PJM 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 has paid uplift to units even when they do not operate as requested by PJM, i.e. when units do not follow dispatch.

PJM and the MMU have defined and worked to implement systematic and verifiable rules for determining when units are following dispatch as a primary screen for eligibility for uplift payments. On October 7, 2025, PJM submitted those rules as tariff revisions. The rules address the fact that, under the status quo, resources receive make whole payments for energy produced while not following PJM's dispatch instructions. The rules were approved by FERC on December 5, 2025. PJM expects to implement the rules in the first half of 2027.

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

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

97 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).

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.[98] 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.[99]

Under RPM, capacity obligations are annual.[100] 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.[101] 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.[102] 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.[103] 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.[104] If the installed reserve margin resulting from the total UCAP committed through self supply or BRAs for three consecutive years is more than one percentage point 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 2026/2027 RPM Third Incremental Auction was conducted in the first three months of 2026.

Market Structure

- **RPM Installed Capacity.** In the first three months of 2026, RPM installed capacity decreased 30.0 MW or 0.0 percent, from 184,220.8 MW on January 1, to 184,190.8 MW on March 31. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- **Reserves.** Total reserves on June 1, 2025, were 19,999.9 MW, which is 205.1 MW (UCAP) short of the required reserve level of 20,205.0 MW (UCAP). On June 1, 2025, the target installed reserve margin was 17.8 percent, and the actual reserve margin was only 17.6 percent.
- **RPM Installed Capacity by Fuel Type.** Of the total installed capacity on March 31, 2026, 48.2 percent was gas; 20.3 percent was coal; 17.5 percent was nuclear; 4.4 percent was hydroelectric; 2.2 percent was oil; 2.4 percent was wind; 0.3 percent was solid waste; and 4.6 percent was solar.

98 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in this report and include all capacity within the PJM footprint.
99 See 186 FERC ¶ 61,080 (2024), *reh'g order*, 189 FERC ¶ 61,043 (2024).
100 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.
101 See 126 FERC ¶ 61,275 at P 86 (2009).
102 See Letter Order, FERC Docket No. ER10-366-000 (January 22, 2010).
103 See 126 FERC ¶ 61,275 at P 88 (2009). There have been no Conditional Incremental Auctions.
104 See OATT Attachment DD § 16.

- **Market Concentration.** In the 2026/2027 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.[105] 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.[106] [107] [108]

- **Imports and Exports.** Of the 1,144.8 MW of imports offered in the 2027/2028 RPM Base Residual Auction, 1,005.9 MW cleared. Of the cleared imports, 695.6 MW (69.2 percent) were from MISO.

- **Demand Resources.** Committed DR was 5,782.9 MW for June 1, 2025, as a result of cleared capacity for demand resources in RPM auctions for the 2025/2026 Delivery Year (6,265.9 MW) less replacement capacity (483.0 MW).

- **Energy Efficiency Resources.** EE is not a capacity resource but is paid the capacity market clearing price as a subsidy through the 2025/2026 Delivery Year. Committed EE was 1,481.6 MW for June 1, 2025, as a result of MW offered at a price less than or equal to the RPM auction clearing price in RPM auctions for the 2025/2026 Delivery Year (1,493.2 MW) less replacement MW (11.6 MW).

Market Conduct

- **2026/2027 RPM Third Incremental Auction.** Of the 985 generation resources that submitted Capacity Performance offers, unit specific offer caps were calculated for four generation resources (0.4 percent).

Market Performance

- The 2026/2027 RPM Third Incremental Auction was conducted in the first three months of 2026. 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. The weighted average capacity price for the 2026/2027 Delivery Year is $324.88 per MW-day, including all RPM auctions for the 2026/2027 Delivery Year. The weighted average capacity price for the 2027/2028 Delivery Year is $333.44 per MW-day, including all RPM auctions for the 2027/2028 Delivery Year.

- For the 2025/2026 Delivery Year, RPM annual charges to load are $14.9 billion.

- In the 2027/2028 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 2026 was 8.6 percent, an increase from 6.0 percent in the first three months of 2025.[109]

- **Generator Performance Factors.** The PJM aggregate equivalent availability factor in the first three months of 2026 was 84.4 percent, a decrease from 86.1 percent in the first three months of 2025.

Section 5 Recommendations[110]

Definition of Capacity

- The MMU recommends elimination of the key remaining components of the CP model because they interfere with competitive outcomes in the

105 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).

106 See OATT Attachment DD § 6.5.

107 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).

108 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).

109 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 22, 2026. 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.

110 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.

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.[111] [112] (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.[113] (Priority: Medium. First reported 2016. Status: Adopted 2024.)[114]
- 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.)[115]
- 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 PJM's application of the ELCC approach be replaced with an ELCC approach that is based on the actual hourly availability of all individual generators for accreditation and for payment. The MMU recommends short term modifications to PJM's approach 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 inflexible class capacity accreditation ratings derived from a small number of nonrepresentative hours of poor performance from PV1 and WSE. (Priority: High. First reported 2023. Status: Not adopted.)

Market Design and Parameters

- The MMU recommends that PJM establish a load queue for large new data center loads to ensure that such loads are not added until there is adequate generation capacity to serve them. The MMU recommends that an expedited queue option that would permit both the load and the generation to be added without delays be available to large data centers if they bring their own new generation with locational and temporal characteristics reasonably matched to their load profile. (Priority: High. First reported Q2, 2025. Status: Not adopted.)
- 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.

111 See also Comments of the Independent Market Monitor for PJM, Docket No. ER14-503-000 (December 20, 2013).
112 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).
113 "PJM Manual 19: Load Forecasting and Analysis," § 3.2 Development of the Forecast, Rev. 38 (Dec. 17, 2025).
114 See 189 FERC ¶ 61,095 (2024).
115 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).

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 2024. Status: Adopted 2025.)
- 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.)[116]
- 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 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

116 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>.

the process of modifying the obligations to pay for capacity be reviewed. (Priority: Medium. First reported 2021. Status: Not adopted.) [117]

- 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.)[118]
- The MMU recommends that the RPM market power mitigation rules 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.)[119]
- 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.)
- 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.[120] (Priority: High. First reported 2013. Status: Not adopted.)
- The only function the current MOPR is serving now is to create unnecessary administrative work in the application and compliance screening and to

117 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).

118 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).

119 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).

120 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).

create barriers to entry for generation resources. Absent a meaningful change to MOPR, the MMU recommends eliminating the MOPR. (Priority: High. First reported 2025. 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.)
- The MMU recommends that the PJM Tariff be modified to explicitly state that in order to qualify, a Capacity Market Seller requesting a must offer exception based on a financially and physically firm commitment to an external sale of its capacity must provide a confirmed firm transmission reservation, covering the entire path from source to sink, for the full requested ICAP MW of the external sale that covers the entire delivery year, by the tariff defined deadline. The MMU recommends that this language apply to all external sales of Generation Capacity Resources, including those where an external balancing authority does not require this level of transmission service in order to consider a PJM resource as a network resource. (Priority: High. First reported 2025. 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 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 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 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 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, until a decision is made to build transmission as a replacement, and then should be included. (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 2026/2027 RPM Base Residual Auction were significantly affected by flawed market design elements including the lack of a queue for the addition of large new data center loads, by the performance assessment interval (PAI) penalties that are part of the CP design, by PJM's ELCC approach, by the definition of market seller offer caps, by the failure to extend the RPM must offer requirement to demand resources, and by the product definition and lack of market power mitigation for demand 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. PJM filed changes that were approved by FERC and included in the 2026/2027 BRA 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, although PJM failed to include elimination of the categorical exemption for demand resources.[121] [122]

121 See Letter Order, FERC Docket No. ER25-682-001 (April 29, 2025).
122 190 FERC ¶ 61,117 (2025).

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 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 basic conclusion of Part A of the MMU's analysis of the 2026/2027 BRA is that data center load growth is the primary reason for recent and expected capacity market conditions, including total forecast load growth, the tight supply and demand balance, and high prices. But for data center growth, both actual and forecast, the PJM Capacity Market would not have seen the same tight supply demand conditions, the same high prices observed in the 2025/2026 BRA and 2026/2027 BRA or the currently expected tight supply conditions and high prices for subsequent capacity auctions. The combined total increase in capacity market revenues resulting from data center load, both actual and forecast, for the 2025/2026 BRA and the 2026/2027 BRA was $16,603,301,829.[123] [124] This total will continue to grow until the issues associated with the additions of large data center loads are addressed.

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

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

Data center load growth is the core reliability issue facing PJM markets at present. There is still time to address the issue but failure to do so will result in very high costs for other PJM customers and could also result in a switch from competitive markets to cost of service regulation or other distortions of the market design. Customers are already bearing billions of dollars in higher costs as a direct result of existing and forecast data center load as the Market Monitor demonstrated in Part G of the 2025/2026 BRA Analysis report and Part A of the 2026/2027 BRA Analysis Report.[125] [126]

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

For the first time since the introduction of the RPM capacity market design, the 2026/2027 BRA used a VRR curve with both a defined maximum price and a defined minimum price. The maximum and minimum prices were based on the Agreement between Governor Shapiro of Pennsylvania and PJM that was

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

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

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

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

incorporated in a PJM filing with FERC.[127] That VRR curve with the defined maximum and minimum price is referred to in this report as the actual (or restricted) VRR curve. The VRR curve that would have been used absent the Agreement is referred in this report as the unrestricted VRR curve.

The Agreement resulted in a reduction of 2026/2027 BRA revenues of $3,169,915,210, or 16.4 percent, compared to the revenues that would have resulted from the unrestricted VRR curve, holding everything else constant. If the 2026/2027 BRA had been run with an unrestricted VRR curve, total revenues would have been $19,294,286,100, an increase of $3,169,915,210, or 19.7 percent, compared to the actual auction revenues of $16,124,370,889. The Agreement resulted in a reduction of 2027/2028 BRA revenues of $9,913,272,621, or 37.7 percent, compared to the revenues that would have resulted from the unrestricted VRR curve, holding everything else constant. If the 2027/2028 BRA had been run with an unrestricted VRR curve, total revenues would have been $26,324,850,846, an increase of $9,913,272,621, or 60.4 percent, compared to the actual auction revenues of $16,411,578,225. The Agreement resulted in a reduction of combined 2026/2027 and 2027/2028 BRA revenues of $13,083,187,831, or 28.7 percent, compared to the revenues that would have resulted from the unrestricted VRR curve, holding everything else constant.

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 2026/2027 RPM Base Residual Auction, total reserves were 21,353.2 MW, which is 208.7 MW (UCAP) short of the required reserve level of 21,561.9 MW (UCAP). The level of committed demand resources in the 2026/2027 BRA was 5,530.6 MW, meaning the PJM markets will rely on demand resources as part of the required reserve margin, rather than as excess above the required reserve margin. 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 have significantly under performed during recent cold weather and hot weather events. DR capacity resources do not have a defined market seller offer cap. PJM markets for the first time in the 2025/2026 and 2026/2027 Delivery Years 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 the 2025/2026 and 2026/2027 Delivery Years 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 related to demand resources. The RPM must offer requirement is not applied to demand resources. There are no market power mitigation rules that apply to demand resources.

For the 2026/2027 BRA, all participants to which the three pivotal supplier (TPS) test was applied (in the RTO RPM market) failed the three pivotal supplier

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

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.[128] [129]

The correct definition of a competitive offer in the capacity market is the marginal cost of capacity, net ACR, where gross 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, and net ACR includes all energy and ancillary services net revenues as an offset against every element of gross ACR.

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 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 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. There is no effective performance incentive remaining in the capacity market. In the absence of the EFORd design and with the absence of actual or expected regular PAI events, there is no capacity market consequence for failing to perform.

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.

128 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.

129 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).

The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[130] [131] [132] [133] [134] [135] [136] [137] [138] [139] [140] [141] [142] [143] In 2025 and the first three months of 2026, the MMU prepared a number of RPM related reports and testimony, shown in Table 52.

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 57,618.3 MW of additional capacity that cleared in RPM auctions for the 2007/2008 through 2024/2025 Delivery Years, 43,653.8 MW (76.0 percent) were based on market funding. Of the 22,187.4 MW of additional capacity that cleared in RPM auctions for the 2025/2026 through the 2027/2028 Delivery Years, 18,225.0 MW (82.1 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 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 resources include economic demand response (energy market demand resources), emergency demand response, pre-emergency demand response and price responsive demand (PRD) (capacity market demand resources), synchronized reserves and regulation.[144]

  Total demand response revenue increased by $155.3 million, 324.4 percent, from $47.9 million in the first three months of 2025 to $203.2 million in the first three months of 2026, primarily due to increases in capacity market revenue. Emergency demand response revenue accounted for 80.6 percent of all demand response revenue, economic demand response for 8.0 percent, demand response in the synchronized reserve market for 3.0 percent and demand response in the regulation market for 8.3 percent.

  Total emergency demand response revenue increased by $134.8 million, 464.5 percent, from $29.0 million in the first three months of 2025 to $163.8 million in the first three months of 2026.[145] This increase was a result of higher capacity market prices and capacity market revenue.

  Economic demand response revenue increased by $6.0 million, 58.4 percent, from $10.3 million in the first three months of 2025 to $16.3 million in the first three months of 2026.[146] Demand response revenue in the synchronized reserve market increased by $2.9 million, 85.7 percent,

130 See "Analysis of the 2018/2019 RPM Base Residual Auction Revised," (July 6, 2016) <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20182019_RPM_Base_Residual_Auction_20160706.pdf>.

131 See "Analysis of the 2019/2020 RPM Base Residual Auction Revised," (August 31, 2016) <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20192020_RPM_BRA_20160831-Revised.pdf>.

132 See "Analysis of the 2020/2021 RPM Base Residual Auction," (November 11, 2017) <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Analysis_of_the_20202021_RPM_BRA_20171117.pdf>.

133 See "Analysis of the 2021/2022 RPM Base Residual Auction - Revised," (August 24, 2018) <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf>.

134 See "Analysis of the 2022/2023 RPM Base Residual Auction," (February 22, 2022) <https://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20222023_RPM_BRA_20220222.pdf>.

135 See "Analysis of the 2023/2024 RPM Base Residual Auction," (October 28, 2022) <https://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf>.

136 See the "Analysis of the 2024/2025 RPM Base Residual Auction," (October 30, 2023) <https://www.monitoringanalytics.com/reports/Reports/2023/IMM_Analysis_of_the_20242025_RPM_Base_Residual_Auction_20231030.pdf>.

137 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2017," (December 14, 2017) <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Report_on_Capacity_Replacement_Activity_4_20171214.pdf>.

138 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," (September 13, 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>.

139 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>.

140 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>.

141 See Monitoring Analytics, L.L.C., Analysis of the 2025/2026 Base Residual Auction, Parts A through H, <https://www.monitoringanalytics.com/reports/Reports/2024.shtml> and <https://www.monitoringanalytics. com/reports/Reports/2025.shtml>.

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

143 See "Analysis of the 2027/2028 RPM Base Residual Auction – Part A," (January 5, 2026) <https://www.monitoringanalytics.com/reports/Reports/2026/IMM_Analysis_of_the_20272028_RPM_Base_Residual_Auction_Part_A_20260105.pdf>.

144 Emergency demand response refers to both emergency and pre-emergency demand response.

145 The total credits and MWh numbers for demand resources were downloaded as of April 13, 2026, and may change as a result of continued PJM billing updates.

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

from $3.3 million in the first three months of 2025 to $6.2 million in the first three months of 2026. Demand response revenue in the regulation market increased by $11.7 million, 222.7 percent, from $5.2 million in the first three months of 2025 to $16.9 million in the first three months of 2026.

- **Demand Response Energy Payments are Uplift.** Energy payments to emergency and economic demand response resources are uplift. LMP does not cover energy payments to demand response resources although emergency demand response and economic demand response can and do set LMP. Energy payments to emergency demand resources are paid by PJM market participants in proportion to their net purchases in the real-time energy 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.[147]

- **Demand Response Market Concentration.** The ownership of economic demand response resources was highly concentrated in the first three months of 2025 and 2026. The HHI for economic demand response resource reductions increased by 371 points from 8199 in the first three months of 2025 to 8570 in the first three months of 2026.

  The ownership of emergency demand response resources is highly concentrated. The HHI for emergency demand response resources committed MW was 2387 for the 2024/2025 Delivery Year. In the 2024/2025 Delivery Year, the four largest CSPs owned 88.5 percent of all committed emergency demand response UCAP MW. The HHI for emergency demand response committed MW is 2517 for the 2025/2026 Delivery Year. In the 2025/2026 Delivery Year, the four largest CSPs own 86.7 percent of all committed demand response UCAP MW.

- **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. In addition, 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 payments have been eliminated from PJM markets effective June 1, 2026. Energy efficiency resources are not capacity resources in PJM and do not clear in the capacity market. 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 2025/2026 Delivery Year. In the 2025/2026 Delivery Year, payments to EE are $148 million.

- **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 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 2025/2026 Delivery Year, with an HHI value of 2804. In the 2025/2026 Delivery Year, the four largest companies own 96.0 percent of all paid Energy Efficiency MW.

Section 6 Recommendations

- The MMU recommends that PJM report the response of emergency demand response 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 performance metric should be (CBL – Metered load)/(CBL – FSL). The current approach significantly overstates the expected response to PJM dispatch. (Priority: High. First reported 2023. Status: Not adopted.)

147 "PJM Manual 28: Operating Agreement Accounting," § 11.2.2, Rev. 104 (March 1, 2026).

- The MMU recommends that FSL registrations be required to reduce to their FSL and GLD registrations be required to reduce by their committed amount in every event hour. (Priority: High. First reported 2025. Status: Not adopted.)
- The MMU recommends that emergency demand response 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 emergency demand response 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 emergency demand response resources be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate.[148] (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that the maximum offer for emergency demand response resources and price response 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 emergency demand response resources be treated as economic resources, responding to economic price signals like other capacity resources. The MMU recommends that emergency demand response resources not be treated as emergency resources. The MMU recommends that emergency demand response resources be available for every hour of the year. (Priority: High. First reported 2012. Status: Partially adopted.)
- The MMU recommends that the Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market prices is already provided in the economic program. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends that, if emergency demand response resources remain in the capacity market, a daily energy market must offer requirement apply to emergency demand response resources, comparable to the rule applicable to generation capacity resources.[149] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that emergency demand response 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 emergency demand response 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.)

148 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).

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

- The MMU recommends that measurement and verification methods for all 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. Compliance by demand resources with PJM dispatch instructions should include both increases and decreases in load. (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.[150] (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends demand response event compliance be calculated on a five minute basis for all emergency demand response resources and that the penalty structure reflect five minute compliance. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends that demand response 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 economic 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 emergency demand response resources 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.)
- 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.[151])
- The MMU recommends that all demand resources register as Pre-Emergency and that the Emergency Program be eliminated. (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends that the lead times for emergency demand response 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

150 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.

151 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.

immediately. (Priority: Medium. First reported 2018. Status: Adopted 2024.)[152 153]

- 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 DER aggregations that clear in a capacity auction not be permitted to change status from homogeneous demand response to any other status for any additional auctions for the same delivery year, or for the delivery year. (Priority: High. First reported Q3, 2025. 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 net metering resources be prohibited from participating in wholesale ancillary services markets if they are compensated for the service at the retail level. (Priority: Medium. First reported Q2, 2025. 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.)
- The MMU recommends that PRD be required to respond during a PAI, regardless of whether the real-time LMP at the applicable location meet or exceeds the PRD strike price, to be consistent with all CP resources. (Priority: Medium. First reported Q3, 2025. 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 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

152 See 189 FERC ¶ 61,095.
153 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.

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.[154]

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

154 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).

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.[155] The MMU proposal was based on the BGE load forecasting program and the Pennsylvania Act 129 Utility Program.[156] [157] 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.[158] PJM's proposal includes only a THI curtailment trigger and not an overall load curtailment trigger.

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

155 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>.

156 *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).

157 *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).

158 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, 2018).

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 rules proposed by the MMU.

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.[159] 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. In addition, PRD is not required to respond if the LMP is less than the PRD strike price. This flawed rule meant that PRD did not fully respond during Winter Storm Elliott because PRD offered at the maximum price of $1,849 per MWh.

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 2026 compared to the first three months of 2025. The net effects were that in the first three months of 2026, average energy market theoretical net revenues increased by 213 percent for a new combustion turbine (CT), increased by 144 percent for a new combined cycle (CC), increased by 199 percent for a new coal plant (CP), increased by 64 percent for a new nuclear plant, increased by 1,326 percent for a new diesel (DS), increased by 29 percent for a new onshore wind installation, increased by 65 percent for a new offshore wind installation and increased by 10 percent for a new solar installation.
- The price of natural gas and coal increased in the first three months of 2026. The marginal costs of a new CT and CC were greater than the marginal costs of a new CP in January and February, and lower in March 2026.
- In the first three months of 2026, spark spreads in BGE and Western Hub increased and spark spreads in COMED and PSEG decreased compared to the first three months of 2025. In the first three months of 2026, dark and quark spreads increased in BGE, COMED, PSEG and Western Hub compared to the first three months of 2025.

159 577 U.S. 260 (2016).

- Of the 16 PJM nuclear plants analyzed, all are expected to cover their avoidable costs from energy and capacity market revenues in 2026, 2027 and 2028, 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 recent change to the definition of the VRR curve in the capacity market weakens the connection between the energy and capacity markets by discounting the net revenue offset, overstating net CONE and creating an arbitrary floor price and, as a result, undermines an important part of the fundamental PJM market design.[160]

PJM's introduction of a flawed form of ELCC for defining available unforced capacity has made the definition of reliability less clear. The ELCC derate factors are 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 that result, among other things, in the undervaluing of gas fired generation capacity.

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.[161] On February 19, 2026, the EPA finalized repeal of the core changes of the 2024 amendments to the rule, including the revised filterable particulate matter (fPM) emission standard, restoring the 0.030 lbs/MMBtu standard that became effective in 2012, and eliminating the requirement to use PM Continuous Emissions Monitoring Systems (CEMS).[162]
- **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.[163] (Transport Rule) On March 15, 2021, the EPA finalized decreases to allowable emissions under

160 See Protest of the Independent Market Monitor for PJM, Docket No. ER26-455-000 (December 8, 2025); 194 FERC ¶ 61,049 (2026).
161 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).
162 See *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units: Final Repeal*, EPA–HQ–OAR–2018–0794; FRL–6716.4–02–OAR, 91 Fed. Reg. 9088 (February 24, 2026).
163 CAA § 110(a)(2)(D)(i)(I).

the Cross-State Air Pollution Rule (CSAPR) and the 2008 ozone NAAQS for 10 PJM states.[164] On February 28, 2022, the EPA issued a federal implementation plan for implementation of CSAPR (also known as the Good Neighbor Plan),[165] 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.[166] 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. On January 27, 2026, the EPA proposed approving state implementation plan submissions from eight states, including PJM states Kentucky and Tennessee, for the 2015 ozone NAAQS.[167] Upon becoming final, these states' interstate transport obligations would be resolved without the federal Good Neighbor Plan requirements.

- **NSR/NSPS.** 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.[168] 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.[169]

  New Source Performance Standards (NSPS) set uniform, technology-based emission limits for specific source categories nationwide, pursuant to Section 111 of the CAA. Numeric emission limits based on the Best System of Emission Reduction (BSER). On January 9, 2026, EPA finalized amendments to NSPS for stationary combustion turbines and stationary gas turbines establishing subcategories for new, modified, or reconstructed stationary combustion turbines based on size, rates of utilization, design efficiency, and fuel type. The EPA determined that combustion controls are BSER for NOX emissions for most new, modified, or reconstructed stationary combustion turbines. For one subcategory, new large turbines with high capacity factors, the BSER for NOX is combustion controls with the addition of selective catalytic reduction (SCR).

- **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.[170] Environmental regulations allow stationary emergency RICE that do not meet the emissions limits and are 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.** EPA has for years regulated CO_2 as a pollutant using CAA provisions that apply to pollutants not subject to NAAQS.[171] [172] On February 12, 2026, EPA rescinded the 2009 finding that greenhouse gas

164 *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).
165 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).
166 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.
167 See *Interstate Transport Plan Review for the 2015 Ozone NAAQS*, EPA-HQ-OAR-2025-0192; FRL-12716-01-OAR, 91 Fed. Reg. 4026 (January 30, 2026).
168 42 U.S.C § 7470 et seq.
169 40 CFR § 52.21.
170 See 40 CFR § 63.6640(f).
171 See CAA § 111.
172 On April 2, 2007, the U.S. Supreme Court overruled the EPA's determination that it was not authorized to regulate greenhouse gas emissions under the CAA and remanded the matter to the EPA to determine whether greenhouse gases endanger public health and welfare. Massachusetts v. EPA, 549 U.S. 497. On December 7, 2009, the EPA determined that greenhouse gases, including carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride, endanger public health and welfare. See *Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act*, 74 Fed. Reg. 66496, 66497 (Dec. 15, 2009). In a decision dated June 26, 2012, the U.S. Court of Appeals for the D.C. Circuit upheld the endangerment finding, rejecting challenges brought by industry groups and a number of states. Coalition for Responsible Regulation, Inc., et al. v. EPA, No 09-1322.

(GHG) emissions (e.g., CO_2, methane) endanger public health and welfare, removing the legal foundation for EPA GHG regulation.[173] EPA concluded it lacks statutory authority under CAA Section 202(a) to regulate GHGs for climate change purposes (citing West Virginia v. EPA, Loper Bright, and arguments about "major questions").[174]

- **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.[175]
- **Waters of the United States.** On November 17, 2025, the EPA and the Army Corps of Engineers proposed a rule revising the definition of Waters of the United States in the CWA to fully implement Sackett v. EPA's narrowed requirement that wetlands have a "continuous surface connection" to relatively permanent waters in to be jurisdictional.[176]
- **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.[177] On December 23, 2025, EPA extended the deadlines promulgated in the 2024 rule.[178]
- **Coal Ash.** The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.[179] 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, Vermont and Virginia (as of July 1, 2026) that applies to power generation facilities. The most recent RGGI auction, held on March 11, 2026, cleared at $24.99 per short ton, or $27.55 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 33.7 percent for a new combustion turbine (CT) unit, $16.85 per MWh or 29.4 percent for a new combined cycle (CC) unit and $43.12 per MWh or 115.1 percent for a new coal plant (CP).
- **Offshore Wind.** New Jersey, Maryland and Virginia have taken significant steps to promote offshore wind. New Jersey and Maryland enacted legislation for offshore wind renewable energy credits (ORECs) in 2010.[180] On January 20, 2025, the Trump Administration issued a Presidential Memorandum withdrawing "from disposition for wind energy leasing all

173 See *Rescission of the Greenhouse Gas Endangerment Finding and Motor Vehicle Greenhouse Gas Emission Standards under the Clean Air Act*, EPA-HQ-OAR-2025-0194; FRL-12715-02- OAR, 91 Fed. Reg. 7686 (February 18, 2026).

174 See *id.* at 7702-7710.

175 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).

176 See Sackett v. EPA, 598 U.S. 651 (2023); *Updated Definition of "Waters of the United States,"* EPA-HQ-OW-2025-0322; FRL 11132.1-01- OW, 90 Fed. Reg. 52498 (November 20, 2025).

177 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).

178 See *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category—Deadline Extensions*, EPA-HQ-OW-2009-0819, 90 Fed. Reg. 61328 (December 31, 2025).

179 42 U.S.C. §§ 6901 *et seq.*

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

areas within the Offshore Continental Shelf."[181] The withdrawal effectively puts on hold indefinitely the offshore wind projects in New Jersey and Maryland. On May 5, 2025, the Attorneys General of New Jersey and Maryland, along with the 16 other states, filed suit against the withdrawal of offshore leasing.[182]

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, 2026, 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 $14.6 billion over the ten year period from 2014 through 2023, an average annual RPS compliance cost of $1.5 billion. The compliance cost for 2023, the most recent year with almost complete data, was $2.9 billion.[183]

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, 2026, 97.8 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.

Renewable Generation

- **Renewable Generation.** Wind and solar generation was 7.1 percent of total generation in PJM in the first three months of 2026. RPS Tier I generation was 8.4 percent of total generation in PJM and RPS Tier II generation was 1.9 percent of total generation in PJM in the first three months of 2026. Only Tier I generation is defined to be renewable but Tier I 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 2026, Tier I generation from PJM generators met only 48.5 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

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

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

183 The 2023 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.

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 are not always clear. The price of carbon implied by REC prices ranges from $8.89 per tonne in Ohio to $65.30 per tonne in Virginia. The price of carbon implied by SREC prices ranges from $66.90 per tonne in Pennsylvania to $840.02 per tonne in Washington, DC. The effective prices for carbon compare to the RGGI clearing price in March 2026 of $27.55 per tonne and to the social cost of carbon which is estimated in the range of $50 per tonne.[184] [185] 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.[186] 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.

184 "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>.

185 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>.

186 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 2025 REC and SREC prices in the PJM jurisdictions with RPS. Additional cost impacts are provided in Table 8-9.

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 ten year period from 2014 through 2023 for the ten jurisdictions that had RPS was $1.5 billion, or a total of $14.6 billion over ten years. The RPS compliance cost for 2023, the most recent year for which there is almost complete data, was $2.9 billion.[187] 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 $8.9 billion per year if the carbon price were $24.99 per short ton and emissions levels were five percent below 2025 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 $17.8 billion if the carbon price were $50 per short ton and emission levels were five percent below 2025 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 $24.99 per short ton would be about $6.0 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 2026, PJM was a monthly net exporter of energy in the real-time energy market in all months.[188] In the first three months of 2026, the real-time net interchange was -6,207.8 GWh. The real-time net interchange in the first three months of 2025 was -8,994.5 GWh.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** In the first three months of 2026, PJM was a monthly net exporter of energy in the day-ahead energy market in all months. In the first three months of 2026, the total day-ahead net interchange was -7,434.8 GWh. The day-ahead net interchange in the first three months of 2025 was -9,305.7 GWh.

187 The 2023 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.

188 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.

- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In the first three months of 2026, gross imports in the day-ahead energy market were 49.2 percent of gross imports in the real-time energy market (59.5 percent in the first three months of 2025). In the first three months of 2026, gross exports in the day-ahead energy market were 83.7 percent of the gross exports in the real-time energy market (88.3 percent in the first three months of 2025).
- **Interface Imports and Exports in the Real-Time Energy Market.** In the first three months of 2026, there were net scheduled exports at 11 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 2026, 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 2026, there were net scheduled exports at 12 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 2026, 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 2026, 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 2026, net scheduled interchange was -6,207.8 GWh and net actual interchange was -6,322.3 GWh, a difference of 114.6 GWh. In the first three months of 2025, the difference was 82.8 GWh. This difference is inadvertent interchange.
- **Loop Flows.** In the first three months of 2026, the Northern Indiana Public Service (NIPS) Interface had the largest loop flows of any interface with -148.2 GWh of net scheduled interchange and -3,582.4 GWh of net actual

interchange, a difference of 3,434.1 GWh. In the first three months of 2026, the SOUTH interface pricing point had the largest loop flows of any interface pricing point with 3,130.2 GWh of net scheduled interchange and 5,256.1 GWh of net actual interchange, a difference of 2,125.9 GWh.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In the first three months of 2026, 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 53.2 percent of the hours.
- **PJM and New York ISO Interface Prices.** In the first three months of 2026, 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 57.9 percent of the hours.
- **Neptune Underwater Transmission Line to Long Island, New York.** In the first three months of 2026, 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 84.4 percent of the hours.
- **Linden Variable Frequency Transformer (VFT) Facility.** In the first three months of 2026, 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 81.4 percent of the hours.
- **Hudson DC Line.** In the first three months of 2026, 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 74.1 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 2026, and two such TLRs in the first three months of 2025.
- **Up To Congestion.** The average number of up to congestion bids submitted in the day-ahead energy market increased by 17.0 percent, from 50,614 bids per day in the first three months of 2025 to 59,239 bids per day in the first three months of 2026. The average cleared volume of up to congestion bids submitted in the day-ahead energy market decreased by 25.8 percent, from 266,942 MWh per day in the first three months of 2025, to 197,997 MWh per day in the first three months of 2026.

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 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 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. That increase was not justified when implemented as current data demonstrates and the increase should be removed.

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 2026, the real-time average primary reserve requirement was 3,377.5 MW in the RTO Reserve Zone and 2,701.5 MW in the Mid-Atlantic Dominion Reserve Subzone. In the first three months of 2026, the day-ahead average primary reserve requirement was 3,380.6 MW in the RTO Reserve Zone and 2,695.2 MW in the Mid-Atlantic Dominion Reserve Subzone.
- **Market Concentration.** The Mid-Atlantic Dominion (MAD) Reserve Subzone Market for primary reserve was characterized by structural market power in the first three months of 2026. The average HHI for real-time primary reserve in the RTO Reserve Zone was 1149, which is classified as moderately concentrated. The real-time RTO primary reserve

market was highly concentrated in 1.3 percent of intervals.[189] The average HHI for day-ahead primary reserve in the RTO Zone was 1126, which is classified as moderately concentrated. The day-ahead RTO primary reserve market was highly concentrated in 1.8 percent of hours. The average HHI for real-time primary reserve in the MAD Reserve Subzone was 2554, which is classified as highly concentrated. The real-time MAD primary reserve market was highly concentrated in 80.6 percent of intervals. The average HHI for day-ahead primary reserve in the MAD Reserve Subzone was 2198, which is classified as highly concentrated. The day-ahead time MAD primary reserve market was highly concentrated in 65.6 percent of hours.

Synchronized Reserve Market

Synchronized reserves include all capacity synchronized to the grid and available to provide power 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.

Market Structure

- **Supply.** In the first three months of 2026, the real-time average supply of available synchronized reserve was 5,453.7 MW in the RTO Reserve Zone, of which 2,384.9 MW on average was located in the Mid-Atlantic Dominion Reserve Subzone. In the first three months of 2026, the day-ahead average supply of available synchronized reserve was 6,693.7 MW in the RTO Reserve Zone, of which 3,077.3 MW on average was located in the Mid-Atlantic Dominion Reserve Subzone.

189 FERC defines a highly concentrated market as having an HHI greater than 1800.

- **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 2026 was 2,315.0 MW in the RTO Reserve Zone and 1,864.4 MW in the Mid-Atlantic Dominion Reserve Subzone. The day-ahead average synchronized reserve requirement in the first three months of 2026 was 2,317.1 MW in the RTO Reserve Zone and 1,860.2 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 2026. The average HHI for real-time synchronized reserve in the RTO Reserve Zone was 901, which is classified as unconcentrated. The real-time RTO synchronized reserve market was highly concentrated in 0.1 percent of intervals. The average HHI for day-ahead synchronized reserve in the RTO Zone was 922, which is classified as unconcentrated. The day-ahead RTO synchronized reserve market was highly concentrated in 0.6 percent of hours. The average HHI for real-time synchronized reserve in the MAD Reserve Subzone was 1989, which is classified as highly concentrated. The real-time MAD synchronized reserve market was highly concentrated in 55.6 percent of intervals. The average HHI for day-ahead synchronized reserve in the MAD Reserve Subzone was 1800, which is classified as highly concentrated. The day-ahead MAD synchronized reserve market was highly concentrated in 42.6 percent of hours.

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 Resource model participants, 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.

In December 2024, PJM updated the economic basepoint signal to include deployed reserve MW during synchronized reserve events, improving performance. The yearly average performance in 2024 for events that were 10 minutes or longer was 58.2 percent, while for 2025 it was 78.3 percent and for 2026 it was 72.3 percent. However, significant communications technology and modelling issues when calling resources during spinning events continue to result in slow response from a significant share of resources.

Market Performance

- **Price.** In the first three months of 2026, for the Mid-Atlantic Dominion Reserve Subzone, the weighted average real-time price for synchronized reserve was $6.23 per MWh and the weighted average day-ahead price was $8.11 per MWh. In the first three months of 2026, for the RTO Reserve Zone, the weighted average real-time price for synchronized reserve was $6.38 per MWh and the weighted average day-ahead price was $7.50 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 2026, the real-time average supply of eligible and available nonsynchronized reserve was 1,173.8 MW in the RTO Reserve Zone, of which 783.2 MW on average was available in the Mid-Atlantic Dominion Reserve Subzone. In the first three months of 2026, the real-time average supply of eligible and available nonsynchronized reserve was 1,193.2 MW in the RTO Reserve Zone, of which 739.5 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.[190] 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 reserve due to secondary reserve having 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.[191] Hybrid units and Energy Storage Resource model participants 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 2026, the nonsynchronized reserve weighted average real-time price for all intervals in the RTO Reserve Zone was $2.34 per MWh and the weighted average day-ahead price was $1.96 per MWh. In the first three months of 2026, the nonsynchronized reserve weighted average real-time price for

190 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.1 Overview of the PJM Reserve Markets, Rev. 136 (Oct. 1, 2025).

191 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.3 Reserve Market Resource Offer Structure, Rev. 136 (Oct. 1, 2025).

all intervals in the MAD Reserve Subzone was $2.94 per MWh and the weighted average day-ahead price was $1.48 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. By default, there is no reserve subzone for 30-minute 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 2026, the real-time average supply of available 30-minute reserve was 26,301.7 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 reserve reliability requirement is frequently equal to the primary reserve reliability requirement. In the first three months of 2026, the average 30-minute reserve requirement was 3,453.2 MW in the real-time market and 3,452.3 MW in the day-ahead market.
- **Market Concentration.** The RTO Reserve Zone Market for 30-minute reserves was characterized by low concentration in the first three months of 2026. In the first three months of 2026, the average HHI for real-time 30-minute reserves was 748, which is classified as unconcentrated. The real-time RTO 30-minute reserve market was highly concentrated in 0.1 percent of intervals. In the first three months of 2026, the average HHI for day-ahead 30-minute reserves was 841, which is classified as unconcentrated. The day-ahead RTO 30-minute reserve market was highly concentrated in 0.0 percent of hours.

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 2026, in the RTO Reserve Zone, the real-time average supply of available secondary reserve was 20,180.6 MW and the day-ahead average supply of available secondary reserve was 12,307.3 MW. 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.[192]

Market Conduct

- **Offers.** Energy Storage Resource model participants, 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.[193] 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.

192 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.1 Overview of the PJM Reserve Markets, Rev. 136 (Oct. 1, 2025).
193 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.3 Reserve Market Resource Offer Structure, Rev. 136 (Oct. 1, 2025).

Market Performance

- **Price.** The secondary reserve price is determined by the marginal 30-minute reserve resource. In the first three months of 2026, the secondary reserve real-time price for all intervals was $0.00 per MWh. In the first three months of 2026, the secondary reserve day-ahead price for all hours was $0.00 per MWh.

Regulation Market

The PJM Regulation Market is a real-time market. The regulation market design changed significantly on October 1, 2025. 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.

PJM plans to implement additional changes to the regulation market in a second phase, to be implemented on October 1, 2026. This phase 2 will include separate regulation up and regulation down markets. The Phase 1 changes eliminated many of the significant issues identified by the MMU under the pre-October 1, 2025, design. However, the Phase 1 changes introduced new issues that are significantly affecting market prices.

This report analyzes the results of the regulation market in the first three months of 2026.

Market Structure

- **Supply.** In the first three months of 2026, the average half hour offered supply of regulation for nonramp hours was 958.8 actual MW (835.4 effective MW), 1,117.2 actual MW (967.8 effective MW) for shoulder hours, and 1,200.8 actual MW (1,048.1 effective MW) for ramp hours.
- **Demand.** The half hour regulation demand is 550 MW for nonramp hours, 650 MW for shoulder hours, and 750 MW for ramp hours.
- **Supply and Demand.** The nonramp regulation requirement of 550.0 effective MW was provided by 623.1 hourly average actual MW in the first three months of 2026. The shoulder regulation requirement of 650.0 effective MW was provided by 740.2 hourly average actual MW in the first three months of 2026. The ramp regulation requirement of 750.0 effective MW was provided by 848.9 hourly average actual MW in the first three months of 2026.

  The ratio of the average half hour offered supply of regulation to average half hour regulation demand (actual cleared MW) for nonramp hours was 1.54 in the first three months of 2026. The ratio of the average half hour offered supply of regulation to average half hour regulation demand (actual cleared MW) for shoulder hours was 1.15 in the first three months of 2026. The ratio of the average half hour offered supply of regulation to average half hour regulation demand (actual cleared MW) for ramp hours was 1.41 in the first three months of 2026.
- **Market Concentration.** In the first three months of 2026, the three pivotal supplier test was failed in 84.5 percent of half hours. In the first three months of 2026, the effective MW weighted average HHI was 1268, 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. In the first three months of 2026, there were 217 resources providing regulation.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $148.22 per MW of regulation in first three months of 2026. The weighted average cost of regulation in the first three months of 2026 was $151.56 per MW of regulation.

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).[194]

In the first three months of 2026, total black start charges were $11.4 million, a decrease of $4.8 million (29.4 percent) from the first three months of 2025. In the first three months of 2026, total revenue requirement charges were $11.2 million, a decrease of $4.7 million (29.6 percent) from the first three months of 2025. In the first three months of 2026, total black start uplift charges were $0.2 million, a decrease of $0.04 million (14.9 percent) from 2025. 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 2026 ranged from $0 in the OVEC and REC Zones to $2.2 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.[195] By order issued September 23, 2025, the Commission approved a settlement over the MMU's objection that continued to allow overcompensation.[196] On July 4, 2025, enactment of the One Big Beautiful Bill Act (OBBBA) changed the rules for bonus depreciation again, allowing 100 percent bonus depreciation for assets constructed between January 20, 2025 and December 31, 2028, and placed in service before January 1, 2031.[197] The CRF values for affected units should incorporate 100 percent bonus depreciation. It is essential that PJM not repeat its earlier mistake when it ignored the tax law changes in 2017.

194 OATT Schedule 1 § 1.3BB. There are no ALR units currently providing black start service.
195 See 182 FERC ¶ 61,194.
196 See 193 FERC ¶ 61,059.
197 OBBA § 70301(b)(3).

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.[198] RTOs and their customers are not required to separately compensate generation resources for such reactive capability.[199]

In the first three months of 2026, PJM customers paid $85.6 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 and the order approving PJM's compliance filing.[200]

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.

In the first three months of 2026, total reactive charges were $85.7 million, a decrease of $6.5 million (7.1 percent) from first three months of 2025. In the first three months of 2026, total reactive capability charges were $85.6 million, a decrease of $6.1 million (6.7 percent) from the first three months of 2025. In the first three months of 2026, total reactive service charges were

198 OATT Attachment O.
199 See 182 FERC ¶ 61,033 at P 52 (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).
200 See *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); 192 FERC ¶ 61,113 (2025).

$0.1 million, a decrease of $0.4 million (77.1 percent) from the first three months of 2025.

Total zonal reactive service charges ranged from $0 in the REC and OVEC Zones, to $13.8 million in the AEP Zone in the first three months of 2026.

Primary Frequency Response

On February 15, 2018, the Commission issued Order No. 842, which modified the pro forma large and small generator interconnection agreements and procedures to require all newly interconnecting non-nuclear generating facilities, both synchronous and nonsynchronous, to include equipment for primary frequency response capability as a condition to receive interconnection service.[201] [202]

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 ±0.036 Hz deadband.[203] 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 occurs two to three times per month. A frequency event is declared whenever the system frequency stays outside ±0.040 Hz deadband for at least one minute, and the minimum/maximum frequency reaches ±0.053 Hz.[204] 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. From June 2024 through May 2025, the NERC BAL-003-2 requirement for balancing authorities (PJM is a balancing authority) used a threshold value (L_{10}) equal to ±258.3 MW/0.1 Hz.[205] Effective June 2025 through May 2026, the threshold value (L_{10}) is equal to ±227.6 MW/0.1 Hz.[206]

The MMU has identified several issues with PJM's enforcement and evaluation of generation PFR performance.

Market Procurement of Real-Time Ancillary Services

PJM uses market mechanisms to varying degrees in the procurement of ancillary services including synchronized reserves, primary reserves, 30-minute 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 resource parameters and offers.

All reserve products are jointly cleared with energy in every real-time market solution. The synchronized reserve market clearing is more integrated with the energy market clearing than the other ancillary services because dispatched energy and synchronized reserve are outputs of the same optimization problem for each market interval. 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.[207] Instead, inflexible synchronized reserves are cleared hourly by the Ancillary Service Optimizer (ASO) or the day-ahead energy market.[208] The ASO considers energy market price forecasts, availability of resources for flexible synchronized reserves, and regulation

201 Nuclear Regulatory Commission (NRC) regulated facilities are exempt from this provision. Behind the meter generation that is sized to load is also exempt.

202 Frequency bias settings and frequency response obligations are shared in NERC's Resources Subcommittee <https://www.nerc.com/comm/OC/Pages/Resources-Subcommittee.aspx> and PJM's Operating Committee <https://www.pjm.com/committees-and-groups/committees/oc.aspx>.

203 OATT Attachment O § 4.7.2 (Primary Frequency Response).

204 See PJM. "PJM Manual 12: Balancing Operations," § 3.6.2 Event Selection, Rev. 56 (Oct. 1, 2025).

205 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>.

206 See NERC. "2025 Frequency Bias Settings," Sep. 9, 2025. <https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/rs/oy_2025_frequency_bias_annual_calculations.pdf>.

207 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.4.3 Reserve Market Clearing, Rev. 136 (Oct. 1, 2025).

208 Starting October 1, 2025, the ASO now schedules regulation in half-hour blocks. However, as before the change, the ASO still schedules reserves in one-hour blocks.

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 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 automatically respond to the notifications. (Priority: Medium. First reported 2023. Status: Partially adopted 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 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 increase to the synchronized reserve reliability requirement that PJM added based on a misunderstanding of reserve performance during synchronized reserve events. (Priority: High. First reported 2024. Status: Not adopted.)
- The MMU recommends that reserve resources operating below economic minimum should not be treated as being backed down by that amount to provide reserve. (Priority: Medium. First reported 2025. 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: Adopted 2025.)[209]
- 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: Adopted 2025.)[210]

209 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, was implemented on October 1, 2025, resulting in a single signal, bidirectional market with one clearing price that eliminates the need for an MBF. Phase 1 eliminated RegA and RegD dual offers. Phase 1 reduced 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 is based on the resource's dispatched energy offer schedule, not the lower of its price or cost offer schedule.

210 See *id.*

- 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: Adopted 2025.)[211]
- The MMU recommends that the calculation of the performance score (based on precision, delay and correlation metrics) be replaced. (Priority: Medium. First reported 2023. Status: Partially adopted.).
- The MMU recommends that the performance score be revised to eliminate the effect of the size of the regulation assignment and to directly calculate the performance score based on the actual performance and the requested performance. (Priority: High. First reported 2025. Status: Not adopted.).
- The MMU recommends that the regulation market optimization be reviewed to address the logic that allows the partial clearing of inframarginal resources. (Priority: Medium. First reported 2025. Status: Not adopted.).
- The MMU recommends that if a unit sets its economic maximum at a value greater than its regulation maximum, the lost opportunity cost (LOC) of the unit should be calculated assuming the economic maximum of the unit is equal to the regulation maximum of the unit. The MMU recommends that, in cases where offered ramp is greater than actual ramp, the actual ramp be used to calculate the LOC of the unit. The MMU recommends that these fixes to the LOC logic be implemented prior to implementing Phase 2 of the regulation market design. (Priority: High. New Recommendation. Status: Not adopted.).
- 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: Adopted 2025.).[212]
- The MMU recommends that the lost opportunity cost in all of 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: Adopted 2025.[213] FERC rejected.)[214]
- 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: Adopted 2025. FERC accepted.)[215]
- 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: Adopted 2025.)[216]
- The MMU recommends enhanced documentation of the implementation of the regulation market design. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected.)[217]
- 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

211 See 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).
212 See *id*.
213 This recommendation was adopted by PJM for the energy market and the regulation market. Lost opportunity costs in the energy market and the regulation market are calculated using the schedule on which the unit is scheduled to run.
214 See 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).
215 See *id*.
216 In Phase 1 the ramp rate limited desired MW output is used in the regulation uplift calculation. The MMU does not agree with how this change has been implemented.
217 See *id*.

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.)[218]

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. First reported Q1, 2025. Status: Not adopted.)
- The MMU recommends that PJM develop the metric(s) necessary to objectively evaluate each unit's performance during primary frequency response events. (Priority: Medium. First reported Q2, 2025. 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. First reported Q1, 2025. Status: Not adopted.)
- 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: Adopted 2024.)[219]
- 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. CRF rates effective January 20, 2025, should reflect 100 percent bonus depreciation.[220] (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends that black start planning and coordination be on a regional basis recognizing cross zonal cranking paths and not on a narrowly or purely 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.)
- The MMU recommends that the black start rate under the Base Formula Rate should be based on the actual cost of providing the black start service, plus an incentive, rather than the unsupported use of Net CONE, escalated each year. (Priority: Medium. First reported 2025. Status: Not adopted.)
- The MMU recommends that the fuel assurance rules be modified to recognize actual fuel assured resources within and across zones. (Priority: High. First reported Q2, 2025. Status: Not adopted.)
- The MMU recommends that the Reliability Backstop for black start service be eliminated. There is no reason that PJM cannot acquire black start resources if the TOs can acquire black start resources. (Priority: High. First reported Q2, 2025. Status: Not adopted.)

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

218 See *id.*

219 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. This recommendation will be implemented effective June 1, 2026.

220 OBBA § 70301(b)(3).

market clearing price credits, while based on lower prices, are paid to a larger MW quantity. 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 once during Winter Storm Elliott and once during the July 2025 hot weather event, 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 in reserve requirements were the primary cause of higher reserve prices in 2023, 2024, 2025, and the first three months of 2026, including 35 intervals of shortage pricing in May 2023 and several intervals of shortage pricing during spin events in 2024, 2025, and the first three months of 2026, 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.

Significant communications technology and modelling issues when calling resources during spinning events result in slow response. While PJM now calculates reserve offer MW for the majority of resource types, a resource's cleared reserve MW are based on a resource's energy output at the end of a scheduling interval. If a unit is still moving when an event is called, such as near the beginning of a scheduling interval, it may or may not be able to achieve its scheduled output. Likewise, a unit that is decreasing output to create more headroom might not be able to immediately increase output when an event is called.

Although PJM now augments a resource's economic basepoint with its dispatched reserve MW during a spin event, PJM does not require resources to be able to receive this signal. Many resources are still dispatched using phone calls, either from markets operation centers waiting for the PJM ALL-CALL or from MOCs themselves manually calling plant personnel.

Even if a unit is on AGC and receiving the augmented basepoint, depending on where that unit finds itself on its ramp rate curve, it might have to spend time coming off AGC or decreasing output in order to start ramping using power augmentation. Having a synchronized reserve maximum that is less than the unit's economic maximum can address this case, but it is the unit's responsibility to request the exception.

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 and by requiring the actual use of the signal. The archaic telephone communications technology has been a source of slow response times, such as markets operation centers waiting for the PJM ALL-CALL or manually calling unit personnel to deploy reserves. 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 automatically 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 nor that the receiving units be able to follow the signal for deploying reserves. Further improvements in communications technology and requirements 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 and DSR 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 improved communications technology, 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 increase to the synchronized reserve reliability requirement in place from May 2023 through March 2026.

PJM will implement significant changes to the regulation market in two phases.[221] Phase 1, implemented on October 1, 2025, is a single product, single signal market with one clearing price. Phase 2, to be implemented on October 1, 2026, will include separate regulation up and regulation down markets. The Phase 1 changes eliminated 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. The actual implementation of the new design is flawed, but the design is significantly improved. Significant new issues were created by Phase 1 that significantly affect price and should be fixed as soon as possible.

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 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 not competitive. The MMU concludes that the secondary reserve market results were competitive. The MMU concludes that the regulation market results were not competitive, and that the pre-October 1, 2025 market design is significantly flawed.

221 See 187 FERC ¶ 61,173.

Overview: Section 11, Congestion and Marginal Losses

Congestion Cost

- **Total Congestion.** Total congestion costs increased by $1,511.9 million or 300.4 percent, from $503.3 million in the first three months of 2025 to $2,015.2 million in the first three months of 2026.
- **Day-Ahead Congestion.** Day-ahead congestion costs increased by $1,577.2 million or 224.2 percent, from $703.5 million in the first three months of 2025 to $2,280.7 million in the first three months of 2026.
- **Balancing Congestion.** Negative balancing congestion costs increased by $65.3 million, from -$200.2 million in the first three months of 2025 to -$265.5 million in the first three months of 2026. Negative balancing explicit charges decreased by $7.2 million, from -$94.5 million in the first three months of 2025 to -$87.3 million in the first three months of 2026.
- **Real-Time Congestion.** Real-time congestion costs increased by $1,614.0 million, from $854.2 million in the first three months of 2025 to $2,468.2 million in the first three months of 2026.
- **Monthly Congestion.** Monthly total congestion costs in the first three months of 2026 ranged from $171.4 million in March to $1,205.7 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 Bedington Transformer, the Pruntytown Transformer, the Bedington – Black Oak Interface, the Pruntytown Circuit Breaker, and the Conastone – Northwest Line.
- **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 2026. The number of congestion event hours in the day-ahead energy market was about 2 times the number of congestion event hours in the real-time energy market.

Day-ahead congestion frequency decreased by 1.2 percent from 20,824 congestion event hours in the first three months of 2025 to 20,569 congestion event hours in the first three months of 2026.

Real-time congestion frequency increased by 19.6 percent from 8,416 congestion event hours in the first three months of 2025 to 10,069 congestion event hours in the first three months of 2026.

- **Congested Facilities.** Day-ahead, congestion event hours decreased on interfaces and lines and increased on transformers and flowgates.

  The Bedington Transformer was the largest contributor to congestion costs in the first three months of 2026. With $374.7 million in total congestion costs, it accounted for 18.7 percent of the total PJM congestion costs in the first three months of 2026.

- **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 2025 or 2026.

- **Zonal Congestion.** DOM had the highest zonal congestion costs among all control zones in the first three months of 2026. DOM had $356.7 million in zonal congestion costs, comprised of $407.7 million in day-ahead congestion costs and -$51.0 million in balancing congestion costs.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs increased by $431.2 million or 100.5 percent, from $428.9 million in the first three months of 2025 to $860.0 million in the first three months of 2026. The loss MWh in PJM increased by 198.0 GWh or 4.1 percent, from 4,794.8 GWh in the first three months of 2025 to 4,992.8 GWh in the first three months of 2026. The loss component of real-time LMP in the first three months of 2026 was $0.08, compared to $0.04 in the first three months of 2025.

- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs increased by $429.3 million or 95.5 percent, from $449.7 million in the first three months of 2025 to $879.0 million in the first three months of 2026.

- **Balancing Marginal Loss Costs.** Negative balancing marginal loss costs decreased by $1.8 million or 8.9 percent, from -$20.8 million in the first three months of 2025 to -$19.0 million in the first three months of 2026.

- **Total Marginal Loss Surplus.** The total marginal loss surplus increased by $165.2 million or 105.1 percent, from $157.3 million in the first three months of 2025, to $322.5 million in the first three months of 2026.

- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in the first three months of 2026 ranged from $94.3 million in March to $517.4 million in January.

System Energy Cost

- **Total System Energy Costs.** Total system energy costs decreased by $267.1 million or 98.6 percent, from -$270.9 million in the first three months of 2025 to -$538.0 million in the first three months of 2026.

- **Day-Ahead System Energy Costs.** Day-ahead system energy costs decreased by $277.7 million or 90.3 percent, from -$307.5 million in the first three months of 2025 to -$585.2 million in the first three months of 2026.

- **Balancing System Energy Costs.** Balancing system energy costs decreased by $1.0 million or 2.7 percent, from $39.0 million in the first three months of 2025 to $38.0 million in the first three months of 2026.

- **Monthly Total System Energy Costs.** Monthly total system energy costs in the first three months of 2026 ranged from -$323.8 million in January to -$59.6 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.

The current ARR/FTR design should ensure but 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 2025/2026 planning period was 55.3 percent. The cumulative offset of congestion by ARRs for the 2011/2012 planning period through the first ten months of the 2025/2026 planning period, using the rules effective for each planning period, was 66.0 percent. Load has received $6.8 billion less than load should have received from the 2011/2012 planning period through the first ten months of the 2025/2026 planning period.

Overview: Section 12, Generation and Transmission Planning

Generation Interconnection Planning

Existing Generation Mix

- As of March 31, 2026, PJM had a total installed capacity of 203,028.6 MW, of which 38,366.4 MW (18.9 percent) are coal fired steam units, 57,047.7 MW (28.1 percent) are combined cycle units and 33,452.6 MW (16.5 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 203,028.6 MW of installed capacity, 75,558.5 MW (37.2 percent) are from units older than 40 years, of which 30,814.3 MW (40.8 percent) are coal fired steam units, 255.0 MW (0.3 percent) are combined cycle units and 25,550.6 MW (33.8 percent) are nuclear units.

Generation Retirements[222]

- As of March 31, 2026, there were 64,202.9 MW of generation that have been, or are planned to be, retired between 2011 and 2031, of which 46,526.8 MW (72.5 percent) are coal fired steam units.
- In the first three months of 2026, 2.0 MW of generation retired. The largest generator that retired in the first three months of 2026 was the 2.0 MW Beckjord Storage Unit 1 battery unit located in the DUKE Zone. Of the 2.0 MW of generation that retired in the first three months of 2026, 2.0 MW (100.0 percent) were located in the DUKE Zone.
- As of March 31, 2026, there were 8,455.3 MW of generation that have requested retirement after March 31, 2026, of which 2,671.9 MW (31.6 percent) are located in the COMED Zone. Of the generation requesting retirement in the COMED Zone, 1,527.9 MW (57.2 percent) are combustion turbine natural gas units.

Generation Queue

New Service Requests Serial Process[223]

- On November 29, 2022, the Commission issued an order accepting PJM's tariff revisions to improve the queue process.[224] The new queue process includes modifications to implement a cluster/cycle based processing method to replace the first in/first out serial processing method.[225] 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.
- There were 8,190 generation request projects submitted in the new service request serial process queue from 1997 until the implementation of the new cycle process on July 10, 2023. As a result of the transition to the

222 See PJM. Planning. "Generator Deactivations," (Accessed on March 31, 2026) <https://www.pjm.com/planning/service-requests/gen-deactivations>.
223 See PJM. Planning. "Serial Service Request Status," (Accessed on March 31, 2026) <https://www.pjm.com/planning/service-requests/serial-service-request-status>.
224 See 181 FERC ¶ 61,162 (2022).
225 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>.

new services cycle process, 312 projects (40,650.1 MW) were moved to transition cycle 1 (TC1). There were 1,347 projects eligible to resubmit for evaluation in transition cycle 2 (TC2). Of those 1,347 eligible projects, 550 projects (49,168.4 MW) resubmitted and are now being evaluated in TC2. Of the 1,347 eligible projects, 797 projects (53,155.5 MW) did not resubmit, and were withdrawn from the queue. There were 1,070 projects initially entered into the AH2 queue and beyond. Those 1,070 projects (70,729.8 MW) are now considered invalid and have been removed from the queue. As a result of the transition to the cycle process, the 8,190 projects in the serial process queue have been reduced to 5,461 projects. Projects that will be evaluated in TC1 and TC2, and those projects no longer eligible to be evaluated in the serial process have been removed from the new service requests serial process metrics. New service requests cycle process metrics are reported separately from the serial process metrics.

- As of March 31, 2026, a total of 40,220.7 MW, on an energy basis, were in generation request serial service queues in the status of active, under construction or suspended.[226] Based on historical completion rates, 21,232.8 MW (52.8 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 5,312.5 MW, on an energy basis, of thermal projects (including combined cycle, CT natural gas, CT oil and coal fired steam projects) in the serial queue, 3,775.7 MW (71.1 percent) are expected to go in service based on historical completion rates as of March 31, 2026.
- Of the 3,090.4 MW, on an energy basis, of battery projects in the serial queue, only 834.5 MW (27.0 percent) are expected to go in service based on historical completion rates as of March 31, 2026.
- Of the 31,773.8 MW, on an energy basis, of renewable projects in the serial queue, 16,600.0 MW (52.2 percent) are expected to go in service based on historical completion rates as of March 31, 2026.
- Of the 5,140.6 MW, on a capacity basis that requested CIRs, of thermal projects (including combined cycle, CT natural gas. CT oil and coal fired steam projects) requested in the generation serial queues in the status of active, under construction or suspended, 3,587.9 MW (69.8 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 2028/2029 Base Residual Auction,[227] the 5,140.6 MW of capacity requests currently under construction, suspended or active in the serial queue would be reduced to 2,713.4 MW of capacity (52.8 percent of the total requested capacity).[228]
- Of the 2,082.6 MW, on a capacity basis that requested CIRs, of battery projects requested in the generation serial queues in the status of active, under construction or suspended, 234.1 MW (11.2 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 2028/2029 Base Residual Auction, the 2,082.6 MW of capacity requests currently under construction, suspended or active in the serial queue would be reduced to 138.1 MW of capacity (6.6 percent of the total requested capacity).
- Of the 16,418.1 MW, on a capacity basis that requested CIRs, of renewable projects requested in the serial generation queues in the status of active, under construction or suspended, 8,575.2 MW (52.2 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 2028/2029 Base Residual Auction, the 16,518.1 MW of capacity requests currently under construction, suspended or active in the serial queue would be reduced to 986.5 MW of capacity (6.0 percent of the total requested capacity).
- As of March 31, 2026, 23,685.3 MW of capacity requests (requested CIRs) were in the generation serial queues in the status of active, under construction or suspended. Based on historical completion rates, 12,419.2

226 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.

227 Unless otherwise noted, the ELCC derate factors in this section are based on the *ELCC Class Ratings for 2028/2029 Base Residual Auction*, PJM Interconnection L.L.C. (February 25, 2026) <https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/28-29-bra-elcc-class-ratings.pdf>.

228 Unless otherwise noted, the ELCC derate adjusted MW are calculated using the 2028/2029 Base Residual Auction ELCC factors. 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.

MW (52.4 percent) are expected to go into service. Based on historical completion rates and the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction, the 23,685.3 MW of capacity requests currently under construction, suspended or active in the serial queue would be reduced to 3,859.2 MW of capacity (16.3 percent of the total requested capacity).

- As of March 31, 2026, 5,461 projects, representing 609,227.4 MW, have entered the serial queue process since its inception. Of those, 1,284 projects, representing 95,178.1 MW (15.6 percent of the MW), went into service. Of the projects that entered the serial queue process, 3,769 projects, representing 473,828.6 MW (77.8 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 2026, 40.1 MW from the serial queue went into service. Of the 40.1 MW that went in service, 15.7 MW (39.1 percent) were battery units, 12.6 MW (31.5 percent) were wind units and 11.8 MW (29.4 percent) were solar units.
- Of the 2,809 projects that entered the serial queue from January 1, 2015, through July 10, 2023, 2,062 projects (73.4 percent) were renewable. Of the 690 projects that entered the serial queue in 2020, 545 projects (79.0 percent) were renewable. Renewable projects make up 85.0 percent of all projects in the serial queue and account for 79.0 percent of the nameplate MW currently active, suspended or under construction in the serial queue as of March 31, 2026.
- On March 31, 2026, 28,919.1 MW, on an energy basis, were in generation request serial queues that had reached the construction service agreement milestone or equivalent, in the status of active, suspended or under construction. Of the 28,919.1 MW, 11,200.2 MW (38.7 percent) had not begun construction, 7,551.8 MW (26.1 percent) had begun construction, but are now suspended, and 10,167.1 MW (35.2 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.

New Service Requests Cycle Process[229]

Transition Cycle 1 (TC1)

- Transition cycle 1 (TC1) is comprised of 312 proposed generation projects. Those projects make up 40,650.1 MW. On March 31, 2026, all projects in TC1 were either in the status of active, under construction or were withdrawn from the cycle. Of the 40,650.1 MW in TC1, 14,120 MW (34.7 percent) were active or under construction (10,763.0 MW (26.5 percent) were active and 3,357.0 MW (8.2 percent) were under construction) and 26,530.1 MW (65.3 percent) were withdrawn.
- On March 31, 2026, there were 14,120.0 MW, on an energy basis, of which 6,798.9 MW are on a capacity basis that requested CIRs, in TC1 in the status of active or under construction.
- Of the 6,798.9 MW, on a capacity basis that requested CIRs in TC1 in the status of active or under construction, 1,741.7 MW (25.6 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.
- Of the 569.0 MW, on a capacity basis that requested CIRs, of thermal projects (including CT natural gas projects) requested in TC1 in the status of active or under construction, 381.2 MW (67.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.
- Of the 3,727.4 MW, on a capacity basis that requested CIRs, of solar projects requested in TC1 in the status of active or under construction, 372.7 MW (10.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.
- Of the 1,022.0 MW, on a capacity basis that requested CIRs, of battery projects requested in TC1 in the status of active or under construction, 603.0 MW (59.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.

229 See PJM. Planning. "Cycle Service Request Status," (Accessed on March 31, 2026) <https://www.pjm.com/planning/m/cycle-service-request-status>.

- Of the 5,207.9 MW, on a capacity basis that requested CIRs, of renewable projects requested in TC1 in the status of active or under construction, 757.5 MW (14.5 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.

Transition Cycle 2 (TC2) and Reliability Resource Initiative (RRI)

- On December 13, 2024, PJM submitted modifications to its Open Access Transmission Tariff to add provisions, through a one-time reliability based expansion of the projects in TC2.[230] On February 11, 2025, the Commission approved the RRI tariff modifications.[231] The proposed RRI Tariff revisions created a second TC2 application window that enabled RRI projects to join TC2 and be studied for interconnection during the transition period.
- PJM received 97 applications (28.6 GW) of RRI projects during the RRI application window. Of these projects, 48 involved uprates, in which existing resources are modified to increase the economic maximum generation capability, and 49 proposed building new generation. PJM reviewed the submitted RRI projects using the Commission approved scoring criteria, and approved 51 projects (11,577.4 MW).[232] On March 31, 2026, all RRI projects were either in the status of active or withdrawn from the cycle. Of the 11,577.4 MW of approved RRI projects, 7,932.4 MW (68.5 percent) were active and 3,645.0 MW (31.5 percent) were withdrawn.
- Transition cycle 2 (TC2) is comprised of 647 proposed generation projects. TC2 includes 550 projects submitted during the TC2 window, and 97 projects submitted through the RRI window. Those projects make up 77,760.6 MW. On March 31, 2026, all projects in TC2 were either in the status of active, under construction or were withdrawn from the cycle. Of the 77,760.6 MW in TC2, 29,822.6 MW (38.3 percent) were active or under construction (29,742.6 MW (38.2 percent) were active and 80.0 MW (0.1 percent) were under construction) and 47,938.0 MW (61.6 percent) were withdrawn.

230 See *PJM Interconnection L.L.C.* Docket No. ER25-712 (December 13, 2024).
231 190 FERC ¶ 61,084 (February 11, 2025).
232 The RRI proposal was to select the top 50 projects using the approved scoring criteria. The implemented scoring criteria resulted in a tie for the 50th project. This resulted in PJM selecting 51 projects as part of the RRI process.

- On March 31, 2026, there were 29,822.6 MW, on an energy basis, of which 21,719.2 MW are on a capacity basis that requested CIRs, in TC2 in the status of active or under construction.
- Of the 21,719.2 MW, on a capacity basis that requested CIRs in TC2 in the status of active or under construction, 10,753.4 MW (49.5 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.
- Of the 7,337.9 MW, on a capacity basis that requested CIRs, of thermal projects (including combined cycle and CT natural gas projects) requested in TC2 in the status of active or under construction, 5,642.1 MW (76.9 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.
- Of the 6,366.4 MW, on a capacity basis that requested CIRs, of solar projects requested in TC2 in the status of active or under construction, 636.6 MW (10.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.
- Of the 5,122.3 MW, on a capacity basis that requested CIRs, of battery projects requested in TC2 in the status of active or under construction, 3,022.2 MW (59.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.
- Of the 7,919.1 MW, on a capacity basis that requested CIRs, of renewable projects requested in TC2 in the status of active or under construction, 811.2 MW (10.2 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.

Cycle Process Totals[233]

- On March 31, 2026, there were 959 proposed generation projects in the new services cycle process queues. Those projects make up 118,410.7 MW. On March 31, 2026, all projects in the cycle process queues were either

233 As of March 31, 2026, the cycle process totals include those projects included in TC1 and TC2.

in the status of active, under construction or were withdrawn. Of the 118,410.7 MW in the cycle process queues, 43,942.6 MW (37.1 percent) were active or under construction (40,505.6 MW (34.2 percent) were active and 3,437.0 MW (2.9 percent) were under construction) and 74,468.0 MW (62.9 percent) were withdrawn.

- On March 31, 2026, there were 43,942.6 MW, on an energy basis, of which 28,518.1 MW are on a capacity basis that requested CIRs, in cycle process queues in the status of active or under construction.
- Of the 28,518.1 MW, on a capacity basis that requested CIRs in the cycle process queues in the status of active or under construction, 12,495.1 MW (43.8 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.
- Of the 7,906.9 MW, on a capacity basis that requested CIRs, of thermal projects (including combined cycle and CT natural gas projects) requested in cycle process queues in the status of active or under construction, 6,023.6 MW (76.2 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.
- Of the 10,093.8 MW, on a capacity basis that requested CIRs, of solar projects requested in cycle process queues in the status of active, 1,009.4 MW (10.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.
- Of the 6,144.3 MW, on a capacity basis that requested CIRs, of battery projects requested in cycle process queues in the status of active or under construction, 3,625.1 MW (59.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.
- Of the 13,127.0 MW, on a capacity basis that requested CIRs, of renewable projects requested in cycle process queues in the status of active or under construction, 1,568.6 MW (11.9 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.

Serial and Cycle Process Totals

- On July 10, 2023, there were 287,185.2 MW in the status of active, under construction or suspended in the serial queue. As part of the transition to the new cycle process projects were removed from the queue because developers chose to not resubmit their projects in the TC2 queue, invalid projects were removed and must be resubmitted in Cycle 1, and projects were withdrawn as part of the normal queue process. On March 31, 2026, of the 287,185.2 MW, there were 76,230.9 MW (26.5 percent) in the status of active, in service or under construction, 9,428.1 MW (3.3 percent) went in service, and 201,526.2 MW (70.2 percent) have been withdrawn from the queue.
- On March 31, 2026, there were 6,420 proposed generation projects in the combined serial and new services cycle process queues. Those projects make up 727,638.1 MW. On March 31, 2026, projects in the combined serial and cycle process queues were in the status of active, under construction, suspended, in service or were withdrawn. Of the 727,638.1 MW in the combined serial and cycle process queues, 84,163.3 MW (11.6 percent) were active, under construction or suspended, (60,431.0 MW (8.3 percent) were active, 16,180.5 MW (2.2 percent) were under construction and 7,551.8 MW (1.0 percent) were suspended), 95,178.1 MW (13.1 percent) were in service and 548,296.7 MW (75.4 percent) were withdrawn.
- Of the 84,163.3 MW in the combined serial and cycle process queues in the status of active, under construction or suspended, 13,588.1 MW (16.1 percent) are thermal projects.

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, 2026, PJM has completed six market efficiency cycles under Order No. 1000.[234] In February 2024, PJM completed the 2024/2025 market efficiency base case. In May 2024, PJM posted the 2024/2025 Market Efficiency planning assumptions. The long term market efficiency window opened on April 11, 2025, and closed on June 10, 2025. This window accepted proposals to address historical congestion on three identified flowgates. PJM received 14 proposals from five entities. Two projects, submitted by incumbent transmission owners, were selected as the preferred solutions.[235] These projects were presented to, and approved by, the PJM Board on February 12, 2026. There were no projects selected for acceleration in the 2024/2025 Market Efficiency window.

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.

234 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).

235 One of the three identified congestion drivers included in the 2024/2025 Market Efficiency window was addressed in the 2025 RTEP Window 1.

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."[236] Supplemental projects are exempt from competition.
- The average number of supplemental projects expected in each 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 2026 (post Order 890).[237]

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

236 See PJM. "Transmission Construction Status," (Accessed on March 31, 2026) <https://www.pjm.com/planning/m/project-construction>.

237 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).

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.[238] In the first three months of 2026, the PJM Board approved $12.2 billion in upgrades. As of March 31, 2026, the PJM Board has approved $70.8 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, 2026, 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.[239]
- There were 17,593 transmission outage requests submitted in the first 10 months of the 2025/2026 planning period. Of the requested outages, 74.6 percent were planned for less than or equal to five days and 10.1 percent were planned for greater than 30 days. Of the requested outages, 41.8 percent were submitted late according to the rules in PJM's Manual 3.

Section 12 Recommendations

Generation Retirements

- The MMU recommends that CIRs 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 power by requiring high payments for CIRs.[240] (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

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

239 See "PJM Manual 03: Transmission Operations," Rev. 70 (March 4, 2026).

240 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>.

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 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.[241] (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.[242] (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.)

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.)[243]
- 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.)[244]

241 PJM Filing, FERC Docket No. ER22-2110-000 (June 14, 2022); 181 FERC ¶ 61,162 (2022).

242 Ibid.

243 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).

244 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),

- 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.[245] (Priority: Medium. First reported 2015. Status: Not adopted.)

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 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 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

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).

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

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. Rigorous standards that protect customers from risk should be applied to competitive transmission suppliers to ensure that customers receive the benefits of competition.

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.[246] [247]

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. Line ratings should be provided for a range of durations to ensure that operators understand the actual impact of short term flows versus longer term flows when making decisions that affect market prices. 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

246 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.

247 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.

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.

It would be antithetical to competition to permit transmission owners to own black start units under the backstop rules, to own batteries (storage as a transmission asset) or to permit transmission owners to build new generation, all under the antiquated cost of service regulation rules that were displaced by more efficient competitive markets. Such an approach would undermine competitive markets and require market projects built with investors' capital at risk to compete with subsidized resources.

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 is being significantly improved, based on the proposal submitted by PJM on June 14, 2022, and approved by FERC on November 29, 2022.[248] [249] 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 and to reduce uncertainty for new generation.

On March 31, 2026, there were 959 proposed generation projects in the new services cycle process queues. Those projects make up 118,410.7 MW. Of the 118,410.7 MW in the cycle process queues, 43,942.6 MW (37.1 percent) were active or under construction (40,505.6 MW (34.2 percent) were active and 3,437.0 MW (2.9 percent) were under construction) and 74,468.0 MW (62.9 percent) were withdrawn. The volume of withdrawn projects in the new cycle process does not necessarily mean that the new process is not effective. It is important to recognize that the timing of the project withdrawals. Under the new cycle queue process, the impact on the studies that account for withdrawn projects and the impacts on other projects in the queue has been significantly reduced. So far, the transition cycles have remained on schedule while managing withdrawn projects.

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

248 See *PJM*, Docket No. ER22-2110 (June 14, 2022).
249 See 181 FERC ¶ 61,162 (2022).

new process is fully in place and it can be evaluated. It will be approximately two years for the impact of the new cycle process to be known. 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 allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress. There has already been a significant reduction in queue projects as a result of PJM's improvements to the process. 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. Initial results from the transition cycles have shown that developers are withdrawing their projects at the specified decision points, which is helping to remove speculative projects from the queue process sooner. Whether the new cycle process will result in enough new dispatchable and renewable generation to meet system needs cannot be determined until after a full cycle has been completed, projects go in service and completion rates can be evaluated. 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 while ensuring that customers receive the benefits of competition.

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.[250] The Market Monitor filed opposing comments.[251] The Commission rejected the filing, finding (i) "that the lack of a maximum time limit for Commercial Operation Date extensions, which introduces the opportunity to delay commercial operation for an indefinite period of time, would result in a generator replacement process that does not promote the efficient interconnection of new resources;" and (ii) "because the unrestricted opportunity for a Replacement Generation Resource Project Developer to significantly delay commercial operation may result in CIRs and associated transmission capacity dedicated to accommodate the Replacement Generation Resource's operation going unused."[252] PJM filed a new proposal that continued to be flawed. [253] On January 29, 2026, the Commission approved the tariff revisions.[254]

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.[255] [256] 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

250 See PJM Interconnection, L.L.C., Docket No. ER25-1128 (January 31, 2025).
251 See Comments of the Independent Market Monitor for PJM, Docket No. ER25-1128-000 (February 21, 2025).
252 See 192 FERC ¶ 61,137 at PP 38–39 (2025).
253 *See PJM Interconnection, L.L.C.*, Docket No. ER26-403-000 (October 31, 2025).
254 See 194 FERC ¶ 61,079 (January 29, 2026).
255 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>.
256 On April 30, 2024, the CIR Transfer Efficiency issue was transferred from the Interconnection Process Subcommittee (IPS) to the Planning Committee (PC).

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

On February 27, 2026, PJM filed revisions to the tariff to establish an expedited interconnection track (EIT) process for generating facilities.[257] The EIT was designed to expedite the interconnection of new generation that commits to firm commercial in service dates, has a commitment from the relevant siting authority (or a state executive officer in certain circumstances) to expedite consideration of applicable siting, and provides a pathway for new generation.

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.

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. However, 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,

257 See PJM. Docket No. ER26-1563 (February 27, 2026).

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.

Recent proposals from Transmission Owners to use storage as a transmission asset (SATA) raises a number of additional concerns about PJM's benefit/cost analysis. Storage is a market asset and should not be owned by transmission owners. PJM should not be evaluating SATA at all without a decision from FERC that SATA is allowable in PJM. At present, it is not allowed.

A significant flaw in PJM's benefit/cost analysis is that projected benefits are based on load forecasts which are currently dominated by projected large data center loads that are not verified by PJM and cannot be verified by PJM. That creates a bias towards finding transmission projects beneficial despite the fact that data center loads are imposing transmission costs on other customers as a result.

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.[258]

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 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.

258 PJM, "Manual 38: Operations Planning," Rev. 20 (January 22, 2026) at 19-20.

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.[259] 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 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.[260] 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.

259 OATT Part V §114.

260 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 Virginia case illustrates the imposition of transmission costs by data centers on other PJM customers. These additional transmission costs are in addition to the significant capacity market costs imposed on other customers by the actual and forecast addition of large data centers.

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 data center 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 simply 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 (assumed) consistent with the procedures noted in Manual 14B.[261] [262] The RTEP analysis is not adequately coordinated with PJM markets analysis including the energy and capacity markets. In effect, the RTEP process could result in building expensive transmission based on speculation about the location and type of capacity additions and load additions. The related impacts are exacerbated by the uncertainty about the actual additions of large data centers. This approach to planning is inefficient and unsustainable.

261 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>.

262 See "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 58 (December 17, 2025).

Overview: Section 13, FTRs and ARRs

Market Design

- **ARR Target Allocations.** The value of ARRs is defined by the nodal price differences from the Annual FTR Auction and Monthly FTR Auctions, times the MW of the ARR. ARR target allocations are the minimum value of an ARR. If any ARRs are deficient at the end of the planning period, deficient ARR holders will receive an uplift payment that will charged to FTR holders. If FTRs are fully funded at the end of the planning period, ARR holders will receive all surplus congestion revenues, proportional to ARR target allocations.

Market Structure

- **ARR Ownership.** In the 2025/2026 planning period, ARRs were allocated to 1,560 individual participants, held by 130 parent companies, up from 1,523 individual parents, held by 126 parent companies in the 2024/2025 planning period. ARR ownership for the 2025/2026 planning period was unconcentrated with an HHI of 600, down from 610 for the 2024/2025 planning period.

Market Behavior

- **Self Scheduled FTRs.** For the 2025/2026 planning period, 25.9 percent of eligible ARRs were self scheduled as FTRs, up from 25.3 percent for the 2024/2025 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 2025/2026 planning period, ARRs and self scheduled FTRs offset only 55.3 percent of total congestion. Congestion payments by load in some zones were more than offset and congestion payments in other zones were less than offset. Load has been underpaid congestion revenues by $6.8 billion from the 2011/2012 planning period through the first ten months of the 2025/2026 planning period. The cumulative offset for that period was only 66.0 percent of total congestion. If ARR holders had self scheduled all of their allocated ARRs as FTRs for the first ten months of the 2025/2026 planning period, the self scheduled FTR target allocations would have increased the offset from 55.3 percent to 67.9 percent of total congestion.

- **ARR Payments.** For the first ten months of the 2025/2026 planning period, the ARR target allocations, which are defined by the nodal price differences from the Annual FTR Auction and Monthly FTR Auctions times the MW of the ARR, were $1,882.7 million, while PJM collected $2,137.0 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions. For the 2024/2025 planning period, the ARR target allocations were $1,448.1 million while PJM collected $1,664.9 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions.
- **ARR Revenue.** For the first ten months of the 2025/2026 planning period there was enough total day-ahead congestion to pay FTR target allocations. However, as a result of the monthly settlement logic for FTRs and ARRs, $93.2 million of FTR auction revenue over ARR target allocations was transferred from ARR holders (load) to FTR holders. In the 2024/2025 planning period all $196.2 million of FTR auction revenue over ARR target allocations was transferred from ARR holders 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 2025/2026 planning period, as a result of transmission being returned to service from outages included in the annual model, PJM allocated a total of 25,401.9 MW of residual ARRs, down 2,632.2 MW (a 9.4 percent decrease) from 28,034.1 MW, with a total target allocation of $76.0 million, up $53.9 million (a 243.8 percent increase) from $22.1 million in the same period of the 2024/2025 planning period.
- **ARR Deficiency.** In July 2025, there was not enough FTR auction revenue collected from the monthly FTR auction to pay the high target allocations from Residual ARRs. As a result, July ARR funding was deficient for the first time since ARRs were introduced. Deficient ARRs will be funded at the end of the planning period from surplus FTR revenues, if there is an FTR surplus, or through an uplift charge to FTR holders if there is not an FTR surplus.
- **ARR Reassignment for Retail Load Switching.** There were 31,342 MW of ARRs associated with $1.6 million of revenue that were reassigned for the first ten months of the 2025/2026 planning period. There were 27,940 MW of ARRs associated with $0.9 million of revenue that were reassigned in the same period of the 2024/2025 planning period.

Financial Transmission Rights

Market Design

- **FTR Target Allocations.** The value of FTRs is defined as the day-ahead CLMP difference between the source and sink of the FTR times the MW of the FTR. FTR Target allocations are the maximum value of an FTR. If the FTR target allocations are greater than the congestion revenue paid in the planning period, payments to all FTRs are prorated, proportional to FTR target allocations.
- **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.**[263] For the Monthly Balance of Planning Period Auctions, financial entities purchased 96.6 of all prevailing and counter flow FTRs, including 95.5 percent of prevailing flow and 97.9 percent of

263 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.

counter flow FTRs for the first ten months of the 2025/2026 planning period. Financial entities owned 89.2 percent of all prevailing and counter flow FTRs, including 82.9 percent of all prevailing flow FTRs and 96.0 percent of all counter flow FTRs during the first ten months of the 2025/2026 planning period. Self scheduled FTRs account for 3.4 percent of all FTRs held.

- **Market Concentration.** In the Monthly Balance of Planning Period Auctions for the first ten months of the 2025/2026 planning period, ownership of cleared prevailing flow bids was unconcentrated in all periods. Ownership of cleared counter flow bids was unconcentrated in 68.0 percent of periods and moderately concentrated in 32.0 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 2025/2028 Long Term FTR Auction, total participant FTR sell offers were 1,557,455 MW. In the 2025/2026 Annual FTR Auction, total participant FTR sell offers were 1,695,004 MW. In the Monthly Balance of Planning Period FTR Auctions for the first ten months of the 2025/2026 planning period, total participant FTR sell offers were 63,538,283 MW.
- **Buy Bids.** In the 2025/2028 Long Term FTR auction, total FTR buy bids were 6,729,000 MW, up 72.0 percent from 5,729,618 MW the previous long term auction. There were 6,658,483 MW of buy and self scheduled bids in the 2025/2026 Annual FTR Auction, up 39.6 percent from 4,770.381 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 2025/2026 planning period were 84,841,572 MW.
- **FTR Forfeitures.** Total FTR forfeitures were $4,082,718 for the first ten months of the 2025/2026 planning period, up 30.1 percent from $3,138,663 from the same period of the 2024/2025 planning period.
- **Credit.** There were two collateral defaults and four payment defaults in the first three months of 2026.

Market Performance

- **Quantity.** In the 2025/2028 Long Term FTR Auction 923,869 MW (13.7 percent) of buy bids cleared and 168,852 MW (10.8 percent) of sell offers cleared. In the 2025/2026 Annual FTR Auction 1,324,299 MW (19.9 percent) of buy and self scheduled bids cleared, up 28.8 percent from the 2024/2025 Annual FTR Auction, and 183,410 MW (10.8 percent) of sell offers cleared, up 47.6 percent from the 2024/2025 Annual Auction. In the first ten months of the 2025/2026 planning period, Monthly Balance of Planning Period FTR Auctions 15,117,402 MW (17.8 percent) of FTR buy bids cleared, up 46.5 percent from the same period of the 2024/2025 planning period and 9,708,906 MW (15.3 percent) of FTR sell offers cleared, up 55.3 percent from the same period of the 2024/2025 planning period.
- **Price.** The weighted average buy bid FTR price in the 2025/2028 Long Term FTR Auction was $0.09 per MW, up from $0.07 from the 2024/2027 Long Term FTR Auction. The weighted average buy bid FTR price in the Annual FTR Auction for the 2025/2026 planning period was $0.50 per MW, up from $0.30 per MW in the 2024/2025 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 2025/2026 planning period was $0.43 per MWh, up from $0.42 in the 2024/2025 planning period.
- **Revenue.** The 2025/2028 Long Term FTR Auction generated $162.3 million of net revenue, up 58.2 percent from $102.6 million from the 2024/2027 Long Term FTR Auction. The 2025/2026 Annual FTR Auction generated $1,895.3 million of net revenue, up 28.5 percent from $1,475.3 million for the 2024/2025 Annual FTR Auction. The Monthly Balance of Planning Period FTR Auctions resulted in net revenue of $88.7 million in the first ten months of the 2025/2026 planning period, up 16.0 percent from $76.5 million in the same period of the 2024/2025 planning period.
- **“Revenue Adequacy.”** For the first ten months of the 2025/2026 planning period there was enough total day-ahead congestion revenue to pay FTR target allocations. However, as a result of the monthly settlement logic

for FTRs and ARRs, $93.2 million of FTR auction revenue was transferred from ARR holders (load) to FTR holders in months where congestion revenue was less than FTR target allocation, and FTRs were paid 100.0 percent of the target allocations for the first ten months of the 2025/2026 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 2025/2026 planning period, profits for all participants were $1.9 billion, up from $799.0 million in profits in the same time period in the 2024/2025 planning period and the highest level since the 2013/2014 planning period. In the first 10 months of the 2025/2026 planning period, physical entities received $541.8 million in profits on FTRs purchased directly (not self scheduled), up from $54.3 million profits in the same time period in the 2024/2025 planning period. Financial entities received $1.2 billion in profits, up from $744.7 million profits in the same time period in the 2024/2025 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.)[264]

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

- 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.)
- 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.[265] (Priority: High. First reported 2015. Status: Not adopted.)

265 See "PJM Manual 6: Financial Transmission Rights," Rev. 34 (May 21, 2025).

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 that PJM's minimum credit requirements be reviewed and updated to appropriately reflect the risk created for the markets and other market participants. The PJM minimum credit requirements (minimum tangible net worth and minimum tangible assets) were set as fixed dollars amounts in 2011 in FERC Order No. 741 based on the specific market participation (FTRs or other). (Priority: Medium. First reported Q3 2025. Status: Not adopted.)

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.

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.[266] The FERC order of September 15, 2016, introduced a subsidy to FTR holders at the expense of ARR holders.[267] 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

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

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.

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.[268] 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. For the 2024/2025 planning period, there was not enough congestion revenue to fund FTR target allocations and all FTR auction surplus revenues were taken from load and given to FTR holders. 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 55.3 percent of total congestion paid by load in the first ten months of the 2025/2026 planning period. Load has been underpaid congestion revenues by $6.9 billion from the 2011/2012 planning period through the first ten months of the 2025/2026 planning period. The cumulative offset for that period was only 66.0 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.

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).[269] 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.

268 163 FERC ¶ 61,165 (2018).

269 See 178 FERC ¶ 61,170.

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 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.

2. Recommendations

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.[1] The MMU initiates and proposes changes to the design of the markets and the PJM Market Rules in stakeholder and regulatory proceedings.[2] 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 and working groups regarding market design matters; publishes proposals, reports and studies on market design issues; and makes filings with the Commission on market design issues.[3] 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 the PJM Board.[4] The MMU may provide in its annual, quarterly and other reports "recommendations regarding any matter within its purview."[5]

Recommendation Priority

Priority rankings are relative. The creation of rankings recognizes that there are limited resources available to address market issues and that problems must be ranked in order to determine the order in which to address them. It does not mean that all the problems should not be addressed. Priority rankings are dynamic and as new issues are identified, priority rankings will change. The rankings reflect a number of factors including the significance of the issue for efficient markets, the difficulty of completion and the degree to which items are already in progress. A low ranking does not necessarily mean that an issue is not important, but could mean that the issue would be easy to resolve.

There are three priority rankings: High, Medium and Low. High priority indicates that the recommendation requires action because it addresses a market design issue that creates significant market inefficiencies and/or long lasting negative market effects. Medium priority indicates that the recommendation addresses a market design issue that creates intermediate market inefficiencies and/or near term negative market effects. Low priority indicates that the recommendation addresses a market design issue that creates smaller market inefficiencies and/or more limited market effects or that it could be easily resolved.

Recommendation Status

The MMU also tracks PJM's progress in addressing these recommendations. The MMU recognizes that part of the process of addressing recommendations may include discussions in the stakeholder process, FERC decisions and court decisions and those elements are included in the tracking. The MMU recognizes that PJM does not have the unilateral authority to implement changes to the tariff but PJM has a significant role in the issues PJM focuses on, in proposed changes to the PJM manuals, and in the recommendations PJM makes to the stakeholders and to FERC. Each recommendation includes a status. The status categories are:

- **Adopted:** PJM has implemented the recommendation made by the MMU.
- **Partially adopted:** PJM has implemented part of the recommendation made by the MMU.
- **Not adopted:** PJM does not plan to implement the recommendation made by the MMU, or has not yet implemented any part of the recommendation made by the MMU. Where the subject of the recommendation is pending stakeholder, FERC, or court action, that status is noted.
- **Withdrawn:** The MMU no longer makes the recommendation because it has become irrelevant or because it has been replaced by another recommendation.

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

1 OATT Attachment M § IV.D.
2 *Id.*
3 *Id.*
4 *Id.*
5 OATT Attachment M § VI.A.

competitive results in PJM markets and for continued improvements in the functioning of PJM markets.[6]

In this *2026 Quarterly State of the Market Report for PJM: January through March*, the MMU includes one new recommendation made for the first three months of 2026.

New Recommendation from Section 10, Ancillary Services

- The MMU recommends that if a unit sets its economic maximum at a value greater than its regulation maximum, the lost opportunity cost (LOC) of the unit should be calculated assuming the economic maximum of the unit is equal to the regulation maximum of the unit. The MMU recommends that, in cases where offered ramp is greater than actual ramp, the actual ramp be used to calculate the LOC of the unit. The MMU recommends that these fixes to the LOC logic be implemented prior to implementing Phase 2 of the regulation market design. (Priority: High. New Recommendation. Status: Not adopted.)

Complete List of Current MMU Recommendations

The recommendations are explained in each section of the report.

Section 3, Energy Market

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, including parameter limited schedules. 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.)

6 18 CFR § 35.28(g)(3)(ii)(A); see also OATT Attachment M § IV.D.

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 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 maintenance costs from the Cost Development Guidelines. (Priority: Medium. First reported 2019. Status: Not adopted.)
- 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.)[7]
- 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.)
- 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.)

7 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 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.)[8]

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 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.)

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.)[9]
- 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

8 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.

9 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.

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.)

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.)[10]
- 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.[11] (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.[12] [13] (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.)

10 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.

11 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: Energy Market at 114 – 116.

12 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.

13 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>.

- 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, 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.)[14]
- 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.)[15]

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.)

Section 4, Energy Uplift

- 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.)

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

15 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.

- The MMU recommends that PJM not pay uplift to units for energy produced because of not following dispatch. (Priority: Medium. First reported 2018. Status: Not adopted.)[16]
- The MMU recommends that PJM pay uplift based on the offer at the lower of the actual unit output or the desired MW. (Priority: Medium. First reported 2018. Status: Not adopted.)[17]
- 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.)
- 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.)
- 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

16 PJM filed proposed changes to the uplift rules with the FERC on October 7, 2025 ("Reform to Energy Uplift Credit Rules," Docket No. ER26-59-000). The Commission Order on December 5, 2025, accepted the PJM Proposal as filed. PJM expects to implement the changes in 2027.

17 Id.

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.) [18]

Section 5, Capacity Market

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.[19] [20] (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.[21] (Priority: Medium. First reported 2016. Status: Adopted 2024.)[22]
- 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.)[23]
- 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

18 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).

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

20 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).

21 "PJM Manual 19: Load Forecasting and Analysis," § 3.2 Development of the Forecast, Rev. 38 (Dec. 17, 2025).

22 See 189 FERC ¶ 61,095 (2024).

23 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).

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 PJM's application of the ELCC approach be replaced with an ELCC approach that is based on the actual hourly availability of all individual generators for accreditation and for payment. The MMU recommends short term modifications to PJM's approach 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 inflexible class capacity accreditation ratings derived from a small number of nonrepresentative hours of poor performance from PV1 and WSE. (Priority: High. First reported 2023. Status: Not adopted.)

Market Design and Parameters

- The MMU recommends that PJM establish a load queue for large new data center loads to ensure that such loads are not added until there is adequate generation capacity to serve them. The MMU recommends that an expedited queue option that would permit both the load and the generation to be added without delays be available to large data centers if they bring their own new generation with locational and temporal characteristics reasonably matched to their load profile. (Priority: High. First reported Q2, 2025. Status: Not adopted.)
- 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 2024. Status: Adopted 2025.)
- 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.)[24]
- 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

24 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>.

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 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.) [25]
- 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.)[26]
- The MMU recommends that the RPM market power mitigation rules 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.

25 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).

26 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).

Avoidable costs are the marginal costs of capacity for both new resources and existing resources. (Priority: Medium. First reported 2017. Status: Not adopted.)[27]

- 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.)
- 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.[28] (Priority: High. First reported 2013. Status: Not adopted.)
- The only function the current MOPR is serving now is to create unnecessary administrative work in the application and compliance screening and to create barriers to entry for generation resources. Absent a meaningful change to MOPR, the MMU recommends eliminating the MOPR. (Priority: High. First reported 2025. 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.)

27 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).

28 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).

- 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.)
- The MMU recommends that the PJM Tariff be modified to explicitly state that in order to qualify, a Capacity Market Seller requesting a must offer exception based on a financially and physically firm commitment to an external sale of its capacity must provide a confirmed firm transmission reservation, covering the entire path from source to sink, for the full requested ICAP MW of the external sale that covers the entire delivery year, by the tariff defined deadline. The MMU recommends that this language apply to all external sales of Generation Capacity Resources, including those where an external balancing authority does not require this level of transmission service in order to consider a PJM resource as a network resource. (Priority: High. First reported 2025. 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 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 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 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 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, until a decision is made to build transmission as a replacement, and then should be included. (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 6, Demand Response

- The MMU recommends that PJM report the response of emergency demand response 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 performance metric should be (CBL – Metered load)/(CBL – FSL). The current approach significantly overstates the expected response to PJM dispatch. (Priority: High. First reported 2023. Status: Not adopted.)

- The MMU recommends that FSL registrations be required to reduce to their FSL and GLD registrations be required to reduce by their committed amount in every event hour. (Priority: High. First reported 2025. Status: Not adopted.)
- The MMU recommends that emergency demand response 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 emergency demand response 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 emergency demand response resources be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate.[29] (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that the maximum offer for emergency demand response resources and price response 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 emergency demand response resources be treated as economic resources, responding to economic price signals like other capacity resources. The MMU recommends that emergency demand response resources not be treated as emergency resources. The MMU recommends that emergency demand response resources be available for every hour of the year. (Priority: High. First reported 2012. Status: Partially adopted.)
- The MMU recommends that the Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market prices is already provided in the economic program. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends that, if emergency demand response resources remain in the capacity market, a daily energy market must offer requirement apply to emergency demand response resources, comparable to the rule applicable to generation capacity resources.[30] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that emergency demand response 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 emergency demand response 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

29 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).

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

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 all 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. Compliance by demand resources with PJM dispatch instructions should include both increases and decreases in load. (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.[31] (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends demand response event compliance be calculated on a five minute basis for all emergency demand response resources and that the penalty structure reflect five minute compliance. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends that demand response 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 economic 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 emergency demand response resources 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.)
- 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.[32])
- The MMU recommends that all demand resources register as Pre-Emergency and that the Emergency Program be eliminated. (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends that the lead times for emergency demand response 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.)

31 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.

32 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.

- 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.)[33] [34]
- 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 DER aggregations that clear in a capacity auction not be permitted to change status from homogeneous demand response to any other status for any additional auctions for the same delivery year, or for the delivery year. (Priority: High. First reported Q3, 2025. 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.)

33 See 189 FERC ¶ 61,095.
34 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.

- The MMU recommends that net metering resources be prohibited from participating in wholesale ancillary services markets if they are compensated for the service at the retail level. (Priority: Medium. First reported Q2, 2025. 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.)
- The MMU recommends that PRD be required to respond during a PAI, regardless of whether the real-time LMP at the applicable location meet or exceeds the PRD strike price, to be consistent with all CP resources. (Priority: Medium. First reported Q3, 2025. Status: Not adopted.)

Section 7, Net Revenue

- 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 8, Environmental and Renewables

- 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 9, Interchange Transactions

- 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 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 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 10, Ancillary Services

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 automatically respond to the notifications. (Priority: Medium. First reported 2023. Status: Partially adopted 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 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 increase to the synchronized reserve reliability requirement that PJM added based on a misunderstanding of reserve performance during synchronized reserve events. (Priority: High. First reported 2024. Status: Not adopted.)

- The MMU recommends that reserve resources operating below economic minimum should not be treated as being backed down by that amount to provide reserve. (Priority: Medium. First reported 2025. 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: Adopted 2025.)[35]
- 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: Adopted 2025.)[36]
- 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: Adopted 2025.)[37]
- The MMU recommends that the calculation of the performance score (based on precision, delay and correlation metrics) be replaced. (Priority: Medium. First reported 2023. Status: Partially adopted.).
- The MMU recommends that the performance score be revised to eliminate the effect of the size of the regulation assignment and to directly calculate the performance score based on the actual performance and the requested performance. (Priority: High. First reported 2025. Status: Not adopted.).
- The MMU recommends that the regulation market optimization be reviewed to address the logic that allows the partial clearing of inframarginal resources. (Priority: Medium. First reported 2025. Status: Not adopted.).
- The MMU recommends that if a unit sets its economic maximum at a value greater than its regulation maximum, the lost opportunity cost (LOC) of the unit should be calculated assuming the economic maximum of the unit is equal to the regulation maximum of the unit. The MMU recommends that, in cases where offered ramp is greater than actual ramp, the actual ramp be used to calculate the LOC of the unit. The MMU recommends that these fixes to the LOC logic be implemented prior to implementing Phase 2 of the regulation market design. (Priority: High. New Recommendation. Status: Not adopted.).
- 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: Adopted 2025.).[38]
- The MMU recommends that the lost opportunity cost in all of 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: Adopted 2025.[39] FERC rejected.)[40]
- 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: Adopted 2025. FERC accepted.)[41]
- 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: Adopted 2025.)[42]

35 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, was implemented on October 1, 2025, resulting in a single signal, bidirectional market with one clearing price that eliminates the need for an MBF. Phase 1 eliminated RegA and RegD dual offers. Phase 1 reduced 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 is based on the resource's dispatched energy offer schedule, not the lower of its price or cost offer schedule.
36 See *id.*
37 See 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).
38 See *id.*
39 This recommendation was adopted by PJM for the energy market and the regulation market. Lost opportunity costs in the energy market and the regulation market are calculated using the schedule on which the unit is scheduled to run.
40 See 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).
41 See *id.*
42 In Phase 1 the ramp rate limited desired MW output is used in the regulation uplift calculation. The MMU does not agree with how this change has been implemented.

- The MMU recommends enhanced documentation of the implementation of the regulation market design. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected.)[43]
- 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.)[44]

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. First reported Q1, 2025. Status: Not adopted.)
- The MMU recommends that PJM develop the metric(s) necessary to objectively evaluate each unit's performance during primary frequency response events. (Priority: Medium. First reported Q2, 2025. 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. First reported Q1, 2025. Status: Not adopted.)
- 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: Adopted 2024.)[45]
- 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. CRF rates effective January 20, 2025, should reflect 100 percent bonus depreciation.[46] (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends that black start planning and coordination be on a regional basis recognizing cross zonal cranking paths and not on a narrowly or purely 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.)
- The MMU recommends that the black start rate under the Base Formula Rate should be based on the actual cost of providing the black start service, plus an incentive, rather than the unsupported use of Net CONE,

43 See *id.*
44 See *id.*

45 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. This recommendation will be implemented effective June 1, 2026.
46 OBBA § 70301(b)(3).

escalated each year. (Priority: Medium. First reported 2025. Status: Not adopted.)

- The MMU recommends that the fuel assurance rules be modified to recognize actual fuel assured resources within and across zones. (Priority: High. First reported Q2, 2025. Status: Not adopted.)
- The MMU recommends that the Reliability Backstop for black start service be eliminated. There is no reason that PJM cannot acquire black start resources if the TOs can acquire black start resources. (Priority: High. First reported Q2, 2025. Status: Not adopted.)

Section 11, Congestion and Marginal Losses

There are no recommendations in this section.

Section 12, Planning

Generation Retirements

- The MMU recommends that CIRs 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 power by requiring high payments for CIRs.[47] (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 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.[48] (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.[49] (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.)

47 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*>.

48 PJM Filing, FERC Docket No. ER22-2110-000 (June 14, 2022); 181 FERC ¶ 61,162 (2022).

49 Ibid.

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.)

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.)[50]
- 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.)[51]
- 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.)

50 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).

51 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).

- 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.[52] (Priority: Medium. First reported 2015. Status: Not adopted.)

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 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 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.)

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

Section 13, FTRs and ARRs

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.)[53]

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

- 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.)
- 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.[54] (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 that PJM's minimum credit requirements be reviewed and updated to appropriately reflect the risk created for the markets and other market participants. The PJM minimum credit requirements (minimum tangible net worth and minimum tangible assets) were set as fixed dollars amounts in 2011 in FERC Order No. 741 based on the specific market participation (FTRs or other). (Priority: Medium. First reported Q3 2025. Status: Not adopted.)

54 See "PJM Manual 6: Financial Transmission Rights," Rev. 34 (May 21, 2025).

3. Energy Market

The PJM energy market comprises all types of energy transactions, including the sale or purchase of energy in PJM's Day-Ahead and Real-Time Energy Markets, bilateral and forward markets and self supply. Energy transactions analyzed in this report include those in the PJM Day-Ahead and Real-Time Energy Markets. These markets provide key benchmarks against which market participants may measure results of transactions in other markets.

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 2026.

Table 3-1 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 90.0 percent of the days in the first three months of 2026. The hourly HHI (Herfindahl-Hirschman Index) results indicate that the PJM aggregate energy market in the first three months of 2026 was, on average, unconcentrated by FERC HHI standards. The average HHI was 753 with a minimum of 621 and a maximum of 954. The baseload segment of the supply curve was unconcentrated. The intermediate segment of the supply curve was moderately concentrated. 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 noncompetitive 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 be an issue. 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.[1] 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.[2] 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.[3] 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.[4] [5] [6] 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.

1 OATT Attachment M (PJM Market Monitoring Plan).

2 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).

Overview

Supply and Demand

Market Structure

- **Supply.** In the first three months of 2026, 593 MW of new resources were added in the energy market, and 2 MW of resources were retired.
- The real-time hourly on peak average offered supply in the first three months of 2026 decreased by 2.8 percent, from the first three months of 2025, from 146,532 MWh to 142,490 MWh.

3 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.

4 175 FERC ¶ 61,231 (2021)

5 185 FERC ¶ 61,158 (2023).

6 189 FERC ¶ 61,060 (2024).

- The day-ahead hourly average offered supply in the first three months of 2026 decreased by 3.4 percent, from the first three months of 2025, from 159,428 MWh to 154,058 MWh.
- The real-time hourly average cleared generation in the first three months of 2026 increased by 1.8 percent from the first three months of 2025, from 102,126 MWh to 103,976 MWh.
- The day-ahead hourly average cleared supply in the first three months of 2026, including INCs and UTCs, decreased by 0.2 percent from the first three months of 2025 from 116,697 MWh to 116,436 MWh.
- **Demand.** The real-time hourly peak load without exports in the first three months of 2026 was 135,722 MWh (137,037 MWh with net exports) in the HE 0800 (EPT) on January 29, 2026, lower than the PJM peak load in the first three months of 2025, which was 140,043 MWh (147,704 MWh with net exports) in the HE 0900 (EPT) on January 22, 2025.
- The real-time hourly average load in the first three months of 2026 increased by 3.1 percent from the first three months of 2025, from 95,801 MWh to 98,749 MWh.
- The day-ahead hourly average cleared demand in the first three months of 2026, including DECs and UTCs, increased by 2.2 percent from the first three months of 2025, from 102,310 MWh to 104,565 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 decreased by 8.5 percent and the cleared increment MW decreased by 14.0 percent in the first three months of 2026 compared to the first three months of 2025. The hourly average submitted decrement bid MW increased by 2.5 percent and the cleared decrement MW increased by 1.9 percent in the first three months of 2026 compared to the first three months of 2025. The hourly average submitted up to congestion bid MW decreased by 20.7 percent and the cleared up to congestion bid MW decreased by 25.8 percent in the first three months of 2026 compared to the first three months of 2025.

Market Performance

- **Generation Fuel Mix.** In the first three months of 2026, generation from coal units decreased 1.7 percent, generation from natural gas units increased 4.2 percent, generation from oil units increased 43.2 percent, generation from wind units decreased 4.7 percent, and generation from solar units increased 15.0 percent compared to the first three months of 2025.
- **Fuel Diversity.** The fuel diversity of energy generation in the first three months of 2026, measured by the fuel diversity index for energy (FDI_e), decreased 0.6 percent compared to the first three months of 2025.
- **Marginal Resources.** In the PJM Real-Time Energy Market in the first three months of 2026, coal units were 9.6 percent, natural gas units were 65.9 percent and wind units were 20.2 percent of marginal resources. In the first three months of 2025, coal units were 8.1 percent, natural gas units were 71.1 and wind units were 15.8 percent of marginal resources.
- **Prices.** The real-time load-weighted average LMP in the first three months of 2026 increased $35.37 per MWh, or 67.8 percent, from the first three months of 2025, from $52.20 per MWh to $87.57 per MWh.

  The day-ahead load-weighted average LMP in the first three months of 2026 increased $41.70 per MWh, or 77.8 percent, from the first three months of 2025, from $53.60 per MWh to $95.30 per MWh.
- **Fast Start Pricing.** The real-time load-weighted average PLMP was $87.57 per MWh for the first three months of 2026, which is 8.0 percent, $6.48 per MWh, higher than the real-time load-weighted average DLMP of $81.08 per MWh.
- **Components of Real-Time LMP.** In the PJM Real-Time Energy Market in the first three months of 2026, 47.0 percent of the real-time load-weighted LMP was the result of gas costs, 15.7 percent was the result of transmission constraint violation penalty factors, 5.2 percent was the

result of coal costs, and 2.3 percent was the result of the cost of emission allowances.

- **Components of Day-Ahead LMP.** In the PJM Day-Ahead Energy Market in the first three months of 2026, 25.4 percent of the day-ahead load-weighted LMP was the result of decrement bids, 13.7 percent was the result of increment offers, 25.2 percent was the result of gas costs, and 6.0 percent was the result of coal costs.

- **Changes in Real-Time LMP.** Of the $35.37 per MWh increase in the real-time load-weighted average LMP, $14.92 per MWh (42.2 percent) was the fuel and consumables cost components of LMP, $9.73 per MWh (27.5 percent) was the transmission constraint penalty factor component of LMP, $3.56 per MWh (10.1 percent) was the sum of the markup, maintenance, and ten percent adder components of LMP, $1.26 per MWh (3.6 percent) was the emissions cost components of LMP, and $0.85 per MWh (2.4 percent) was the scarcity component of LMP. The pre-emergency demand response called on by PJM during Winter Storm Fern increased LMP by $0.18 per MWh, 0.5 percent of the increase in LMP. The LMP increase would have been higher if PJM had not imposed a $3,700.00 per MWh administrative cap. The administrative cap reduced the LMP by $0.03 per MWh, a 0.1 percent decrease.

- **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 $6.62 per MWh in the first three months of 2026, and $1.10 per MWh in the first three months of 2025. The larger difference in the first three months of 2026 resulted from conservative operations during Winter Storm Fern when conservatively committed supply did not clear the day-ahead market but operated in the real-time market. 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 86 intervals with five minute shortage pricing on 17 days in the first three months of 2026. Of the 86 intervals, 40 occurred during cold weather from late January into early February, including Winter Storm Fern, for which PJM issued several emergency warnings and actions. Three of the 86 intervals of shortage overlapped with synchronized reserve events.

- **SCED Shortage Intervals.** In the first three months of 2026, there were 1,445 five minute intervals, or 5.6 percent of all five minute intervals, for which at least one RT SCED solution showed a shortage of reserves. In the first three months of 2026, there were 486 five minute intervals, or 1.9 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 2026, PJM triggered shortage pricing for 86 five minute intervals, or 6.0 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 81 days, 90.0 percent of the days, in the first three months of 2026 and 79 days, 87.8 percent of the days, in the first three months of 2025. The overall frequency of pivotal suppliers rose in 2025 and the first three months of 2026 due to an increase in the frequency of days with daily peak load above 130 GW.

- **Local Market Power.** In 2025, in the real-time market, the 500 kV system, 13 zones, and the PJM/MISO interface experienced congestion resulting from one or more constraints binding for 100 or more hours. For eight out of the top 10 congested facilities (by real-time binding hours) in the first three months of 2026, 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 2.1 percent in the first three months of 2025 to 3.4 percent in the first three months of 2026. In the real-time energy market, for units committed to provide energy for local constraint relief, offer-capped unit hours increased from 1.4 percent in the first three months of 2025 to 1.7 percent in the first three months of 2026. 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 promptly.

- **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 zero percent in the first three months of 2025 to 0.02 percent in the first three months of 2026. In the real-time energy market, for units committed for reliability reasons, offer-capped unit hours decreased from 0.13 percent in the first three months of 2025 to 0.01 percent in the first three months of 2026. 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 committed on their least cost schedule as defined in the day-ahead and real-time markets.

- **Parameter Mitigation.** PJM applies operating parameter limits (PLS) to units that fail the TPS test and to all units during hot and cold weather alerts. In the first three months of 2026, 26.2 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, 25.6 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. These units should be committed on their parameter limited schedules to resolve the market power issue. If PJM promptly implemented the FERC approved solution to address the failure to correctly apply market power mitigation, this issue would no longer occur.

- **Frequently Mitigated Units (FMU) and Associated Units (AU).** In the first three months of 2026, no units qualified for an FMU adder. In 2025, 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 -$0.03 when using unadjusted cost-based offers in the first three months of 2026, 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 2026 was more than $900 per MWh and the highest markup 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 $1.48 per MWh in the first three months of 2026, 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 2026 was more than $600 per MWh.[7]

- **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 2026, the unadjusted markup component (net of positive and negative markup components) of LMP was $0.56 per MWh or 0.6 percent of the PJM load-weighted average LMP. February had the highest unadjusted peak markup component, $4.16 per MWh, or 5.2 percent of the real-time peak hour load-weighted average LMP for February.

  In the PJM Day-Ahead Energy Market in the first three months of 2026, the unadjusted markup component (net of positive and negative markup components) of LMP was $1.38 per MWh or 1.4 percent of the PJM load-weighted average LMP. January had the highest unadjusted peak markup component, $5.37 per MWh, or 3.30 percent of the day-ahead peak hour load-weighted average LMP for January.

  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 noncompetitive economic withholding.

- **Markup and Local Market Power.** Comparison of the markup behavior of marginal units with TPS test results shows that for 2.4 percent of all real-time marginal unit intervals in the first three months of 2026, the marginal unit had both local market power, as determined by the TPS test, and a positive markup. The marginal unit had local market power in 20.4 percent of all real-time marginal unit intervals in the first three months of 2026. For 12.0 percent of all marginal unit intervals with local market power, the unit had a positive markup. This occurred in 752 intervals, or 2.9 percent of all real-time market intervals in the first three months of 2026. 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 2026, 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 for 296 marginal unit intervals and 40 day-ahead marginal unit hours. 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.

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, including parameter limited schedules. The short run marginal cost should reflect opportunity cost when appropriate. The MMU recommends that the level of incremental

7 MMU identified an error in the PJM marginal resource identification algorithm within the day ahead clearing optimization. The calculation of generator sensitivity factors requires accurate identification of marginal resources. The error was fixed by the PJM software vendor in March 2025. MMU was unable to calculate the component breakdown for 2024 and the first quarter of 2025 due to the inaccurate identification of marginal resources.

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 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 maintenance costs from the Cost Development Guidelines. (Priority: Medium. First reported 2019. Status: Not adopted.)
- 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.)[8]
- 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

8 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.

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.)
- 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.)[9]

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 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

9 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.

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.)

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.)[10]
- 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.)

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.)[11]
- The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal,

10 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.

11 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.

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.[12] (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.[13] [14] (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, PJM continues to apply a cap to the system marginal price in the pricing

12 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: Energy Market at 114 – 116.

13 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.

14 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>.

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.)[15]
- 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.)[16]

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.)

15 Fuel type is reported by offer schedule, but it can be inaccurate on an hourly basis.
16 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.

Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in the first three months of 2026, 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 2026, LMP increased by $35.37 per MWh compared to the first three months of 2025, or 67.8 percent. The fuel cost components of LMP (the sum of gas, coal, oil, landfill gas, and consumables) increased $14.92 per MWh, 42.2 percent of the increase in LMP. The transmission constraint penalty factor component increased by $9.73 per MWh, 27.5 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 pre-emergency demand response called on by PJM during Winter Storm Fern increased LMP by $0.18 per MWh, 0.5 percent of the increase in LMP. The emissions cost components of LMP, including opportunity costs for emissions limited resources, increased by $1.26 per MWh, 3.6 percent of the increase in LMP. The opportunity costs for emissions alone increased by $1.56 per MWh, 4.4 percent of the increase in LMP. The LMP increase would have been higher if PJM had not imposed a $3,700.00 per MWh administrative cap. The administrative cap reduced the LMP by $0.03 per MWh, a 0.1 percent decrease.

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 2026 generally reflected supply-demand fundamentals, although the behavior of some participants both routinely and during high demand periods represents noncompetitive economic withholding. Economic withholding occurs when generator offers are greater than competitive levels. In the first three months of 2026, the sum of the markup, ten percent adder, and maintenance cost (not short run marginal cost) components increased by $3.56 per MWh or 10.1 percent of the increase in LMP. In the first three months of 2026, PJM actions, in the form of transmission constraint penalty factors, significantly increased prices. In the first three months of 2026, the transmission constraint penalty factor component increased by $9.73 per MWh, 27.5 percent of the increase in LMP.

Data center load growth affects energy market prices. Increased demand without matching energy supply puts upward pressure on prices, all else equal. It is difficult to shield customers from the costs caused by data center load growth in the energy market. The impact on the energy market is greater when data centers are added with adding corresponding generating capacity and its associated energy output.

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.[17] The transmission constraint penalty factors are currently the second largest determinant of LMP after the marginal cost of gas. PJM has not experienced a prolonged load shedding event, but, if one were to occur, LMP could exceed $3,700 per MWh for the entire event.

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 implemented to increase generators' revenue is not consistent with a competitive market design. Changes in the market, like data center load growth and renewable energy growth, do not imply that PJM's current shortage pricing levels are too low. Artificially increasing energy market prices through market design changes is not a solution for managing either data center load growth or renewable energy growth.

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, that scarcity pricing recognize that electric power serves a unique and critical role for customers, 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 in SCED, transmission constraint penalty factors, load forecast bias, hydro resource schedules, fast start pricing, and the treatment of demand resources 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. The transmission constraint penalty factor contribution to the load-weighted average LMP in the first three months of 2026 was $13.76 per MWh or $2.93 billion of the total $18.6 billion cost of real-time load. In the first three months of 2026, the transmission constraint penalty factor contribution to the cost of real time load was nearly three times higher than the $979.8 million collected for energy uplift charges. In the first three months of 2026, the control limit used in RT SCED for 94 percent of violated transmission constraint intervals was less than 100 percent of the actual line limit, with an average reduction of 5.5 percent. If the control limits had not been artificially reduced for PJM transmission constraints and everything else remained unchanged, the transmission constraint penalty factor's contribution to the load weighted average LMP in first three months of 2026 would have decreased by 99.4 percent from $13.76 to $0.08 per MWh. PJM should evaluate its interventions in the market, including the

17 177 FERC ¶ 61,209 (2021).

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, 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. In the first three months of 2026, the pricing run LMP exceeded the dispatch run LMP by $6.48 per MWh in the real-time market. The large difference resulted from high fuel costs during Winter Storm Fern. The fuel costs included in the no load offer for fast start CTs were added to the LMP in the pricing run, creating the majority of the difference. 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.[18] 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 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.

18 See 173 FERC ¶ 61,244 (2020).

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

The question of how to provide market incentives for investment in flexibility, and for operating to the full capability of that flexibility should be addressed directly. Are units inflexible because they are old and inefficient, because they face gas pipeline constraints, 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?

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

The relationship between supply and demand is referred to as supply-demand fundamentals, or economic fundamentals, or market structure. The market structure of the PJM aggregate energy market is only 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 at all times. This assumption requires that the total demand for energy can be met without the supply from any individual supplier or from a small group of suppliers. This assumption is not correct. There are pivotal suppliers in the aggregate energy market with increasing frequency as daily peak loads increase. The frequency of days with aggregate pivotal suppliers was 90.0 percent in the first three months of 2026, compared to 87.8 percent in the first three months of 2025. High markups for some units demonstrate the potential to exercise market power both routinely and during high demand conditions. In the first three months of 2026, 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 for 296, or 0.4 percent of, marginal unit intervals. 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.[19] 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.[20] [21] Many of these issues can be resolved by simple rule changes. PJM filed and, on October 25, 2024, FERC accepted a proposal that requires that sellers that fail the TPS test be offer capped at their cost-based offers and that operating parameters will be mitigated.[22] 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 a software improvement, with no defined date. The flawed rules remain in place. There is no reason to delay implementation of the FERC approved rules until PJM addresses combined cycle modelling. The changes would decrease the solution time for the day-ahead market and enhance market efficiency. The approved approach 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 first three months of 2026 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 results in the exercise of market power in the energy market and provides a reason to use correctly defined short run marginal cost as the sole basis for cost-based

19 The MMU reviews PJM's application of the TPS test and brings issues to the attention of PJM.
20 See 175 FERC ¶ 61,231 (2021).
21 185 FERC ¶ 61,158 (2023).
22 189 FERC ¶ 61,060 (2024).

offers and a reason for implementing an aggregate market power test and correcting the offer capping process for resources with local market power. In addition, PJM's extensive administrative interventions in the energy market should be reduced. The MMU concludes that the PJM energy market results were competitive in the first three months of 2026.

Supply and Demand

Market Structure

Supply

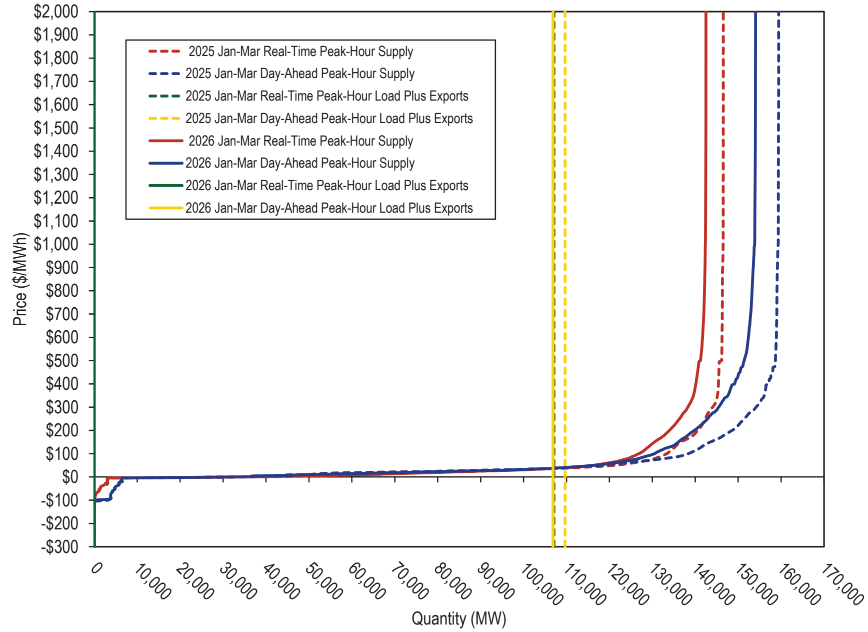
Supply includes physical generation, imports and virtual transactions.

In the first three months of 2026, 593 MW of new resources were added in the energy market, and 2 MW of resources were retired.

Figure 3-1 shows real-time and day-ahead hourly supply curves for the first three months of 2025 and 2026.[23] The real-time supply curve includes hourly on peak average offers. The real-time supply curve only includes available MW from units that are online or have a notification plus start time that is no more than one hour. The day-ahead supply curve shows all available hourly on peak average offers.

The real-time hourly on peak average offered supply in the first three months of 2026 decreased by 2.8 percent, from the first three months of 2025, from 146,532 MWh to 142,490 MWh. The day-ahead hourly average offered supply in the first three months of 2026 decreased by 3.4 percent, from the first three months of 2025, from 159,428 MWh to 154,058 MWh.

Figure 3-1 Real-time and day-ahead hourly supply curves: January through March, 2025 and 2026



23 Real-time supply includes real-time generation offers and import MWh.

Figure 3-2 shows the typical dispatch range.

Figure 3-2 Typical dispatch range of supply curves

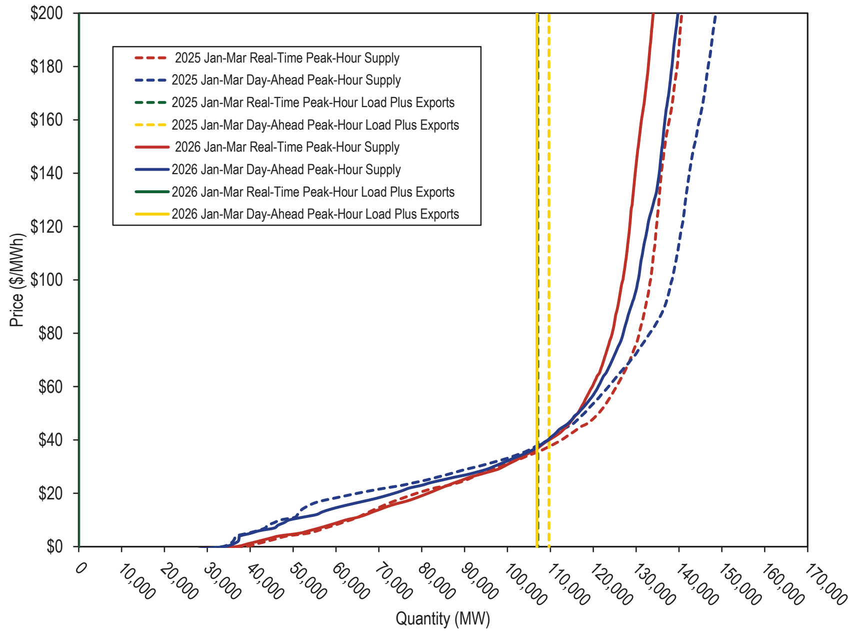


Table 3-2 shows the price elasticity of the real-time supply curve for the peak hours for the first three months of 2020 through 2026 by load level.[24]

The supply curve in the first three months of 2026, while inelastic, was most elastic in the 75 to 95 GW range, with elasticity of 0.390, which was less elastic than the supply curve in the 75 to 95 GW range in the first three months of 2025, with elasticity of 0.830.

The price elasticity of the supply curve measures the responsiveness of the quantity supplied (GW) to a change in price:

The supply curve is defined to be elastic when elasticity is greater than 1.0. The quantity supplied is more sensitive to changes in price the higher the elasticity. Although the aggregate supply curve may appear flat as a result of the wide range in prices and quantities, the supply curve is inelastic throughout.

Table 3-2 Price elasticity of the supply curve

	GW				
Jan-Mar	Min - 75	75 - 95	95 - 115	115 - 135	135 - Max
2020	0.110	1.256	0.414	0.034	0.003
2021	0.078	1.208	0.272	0.066	0.009
2022	0.043	1.039	0.500	0.108	0.016
2023	0.061	0.821	0.219	0.039	0.006
2024	0.076	0.596	0.239	0.034	0.010
2025	0.034	0.830	0.351	0.081	0.017
2026	0.059	0.390	0.289	0.048	0.015

Real-Time Supply

In the PJM Real-Time Energy Market, there are three types of supply offers:[25]

- **Self Scheduled Generation Offer.** Offer to supply a fixed block of MW, as a price taker, from a unit that may also have a dispatchable component above the fixed MW.
- **Dispatchable Generation Offer.** Offer to supply a schedule of MW and corresponding offer prices from a unit.
- **Import.** An import is an external energy transaction scheduled to PJM from another balancing authority. A real-time import must have a valid OASIS reservation when offered, must have available ramp room to support the import, must be accompanied by a NERC Tag, and must pass the neighboring balancing authority checkout process.

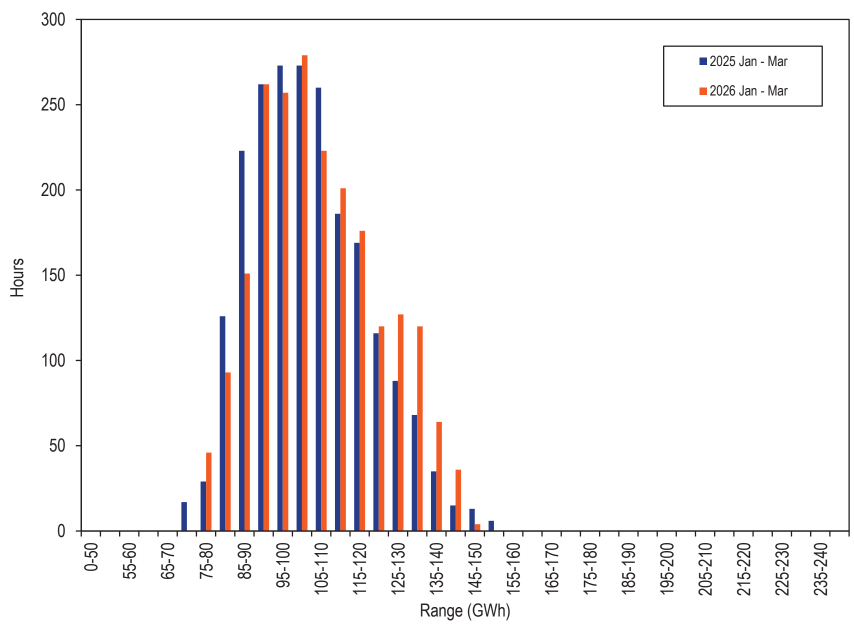
PJM Real-Time Supply Duration

Figure 3-3 shows the hourly distribution of the real-time generation plus imports in the first three months of 2025 and 2026.

24 The price elasticity results have been corrected from previous reports.

25 Generation data are the net MWh injections and withdrawals MWh at every generation bus in PJM.

Figure 3-3 Distribution of real-time generation plus imports: January through March, 2025 and 2026[26]



PJM Real-Time Average Cleared Supply

Table 3-3 shows the real-time hourly average cleared supply and its standard deviation in the first three months of 2026.

The real-time hourly average cleared generation in the first three months of 2026 increased by 1.8 percent from the first three months of 2025, from 102,126 MWh to 103,976 MWh. This was the highest cleared generation since the start of the PJM market for the same period.

The real-time hourly average cleared supply including imports in the first three months of 2026 increased by 2.6 percent from the first three months of 2025, from 104,313 MWh to 106,982 MWh. This was the highest cleared generation including imports since the start of the PJM market for the same period.

Table 3-3 Real-time hourly average generation and generation plus imports: January through March, 2001 through 2026

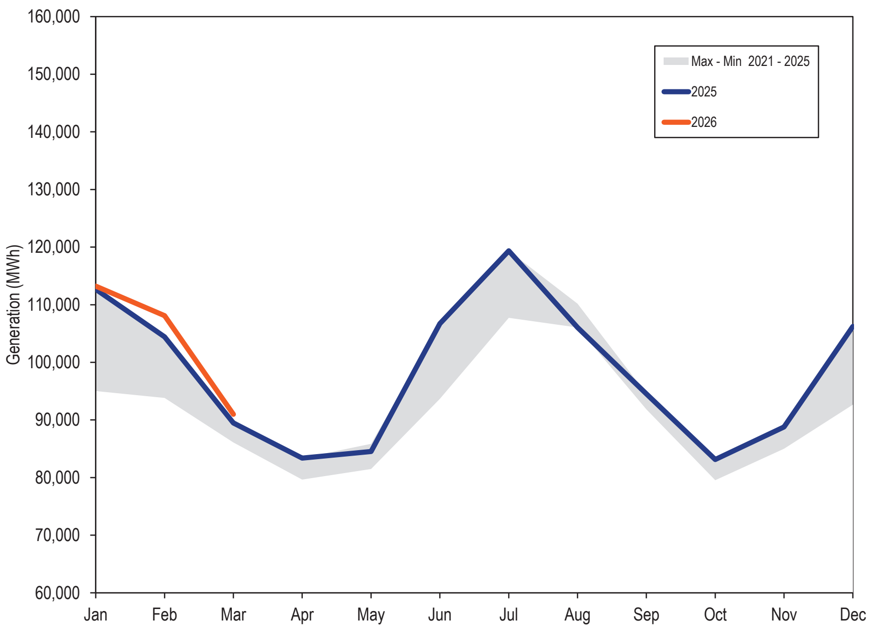
	PJM Real-Time Supply (MWh)				Year-to-Year Change			
	Generation		Generation Plus Imports		Generation		Generation Plus Imports	
Jan-Mar	Generation	Standard Deviation	Supply	Standard Deviation	Generation	Standard Deviation	Supply	Standard Deviation
2001	30,923	3,488	33,806	3,358	NA	NA	NA	NA
2002	27,948	3,416	31,465	3,508	(9.6%)	(2.1%)	(6.9%)	4.5%
2003	38,731	5,187	42,498	5,092	38.6%	51.8%	35.1%	45.2%
2004	37,790	4,660	41,960	4,899	(2.4%)	(10.2%)	(1.3%)	(3.8%)
2005	74,187	8,269	80,184	9,017	96.3%	77.4%	91.1%	84.1%
2006	82,550	7,921	87,729	8,565	11.3%	(4.2%)	9.4%	(5.0%)
2007	86,286	10,018	91,454	11,351	4.5%	26.5%	4.2%	32.5%
2008	86,690	9,375	92,075	10,150	0.5%	(6.4%)	0.7%	(10.6%)
2009	81,987	11,417	88,148	12,213	(5.4%)	21.8%	(4.3%)	20.3%
2010	81,676	12,801	87,009	13,236	(0.4%)	12.1%	(1.3%)	8.4%
2011	83,505	10,116	88,750	10,884	2.2%	(21.0%)	2.0%	(17.8%)
2012	88,068	11,177	93,128	11,685	5.5%	10.5%	4.9%	7.4%
2013	92,776	10,030	98,002	10,812	5.3%	(10.3%)	5.2%	(7.5%)
2014	100,655	12,427	106,879	13,255	8.5%	23.9%	9.1%	22.6%
2015	97,741	13,085	105,027	14,351	(2.9%)	5.3%	(1.7%)	8.3%
2016	88,470	12,666	94,383	13,890	(9.5%)	(3.2%)	(10.1%)	(3.2%)
2017	91,076	11,009	94,390	11,673	2.9%	(13.1%)	0.0%	(16.0%)
2018	95,491	13,151	98,199	14,058	4.8%	19.5%	4.0%	20.4%
2019	97,010	12,379	98,828	12,777	1.6%	(5.9%)	0.6%	(9.1%)
2020	90,675	9,852	91,698	9,992	(6.5%)	(20.4%)	(7.2%)	(21.8%)
2021	96,005	12,057	97,075	12,432	5.9%	22.4%	5.9%	24.4%
2022	98,506	11,686	100,535	12,196	2.6%	(3.1%)	3.6%	(1.9%)
2023	92,936	8,404	94,971	8,836	(5.7%)	(28.1%)	(5.5%)	(27.6%)
2024	95,999	11,547	97,822	11,837	3.3%	37.4%	3.0%	34.0%
2025	102,126	14,587	104,313	15,042	6.4%	26.3%	6.6%	27.1%
2026	103,976	15,033	106,982	15,635	1.8%	3.1%	2.6%	3.9%

PJM Real-Time Monthly Average Cleared Supply

Figure 3-4 compares the real-time monthly average generation in 2025 and the first three months of 2026 with the historic five year range. The real-time monthly average generation in January, February and March in 2026 was higher than the maximum monthly average generation for the past five years.

26 Each range on the horizontal axis excludes the start value and includes the end value.

Figure 3-4 Real-time monthly average generation: 2025 through March 2026



Day-Ahead Supply

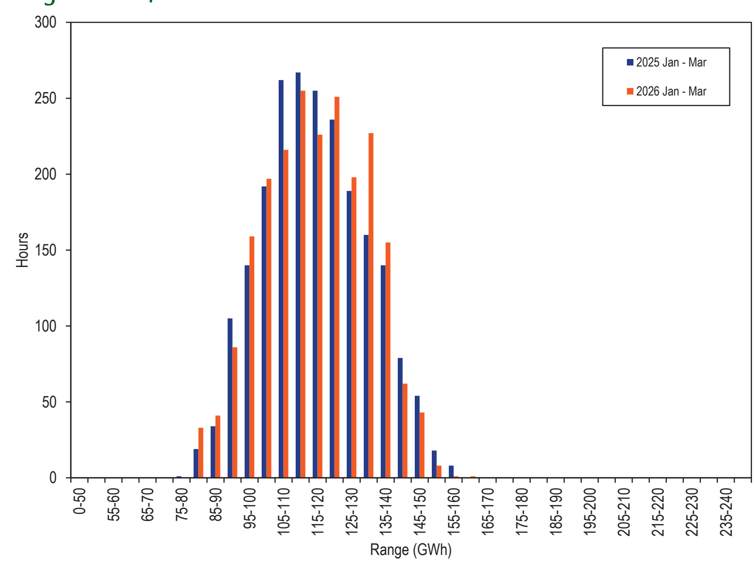
In the PJM Day-Ahead Energy Market, there are five types of financially binding supply offers:

- **Self Scheduled Generation Offer.** Offer to supply a fixed block of MW, as a price taker, from a unit that may also have a dispatchable component above the minimum.
- **Dispatchable Generation Offer.** Offer to supply a schedule of MW and corresponding offer prices from a unit.
- **Increment Offer (INC).** Financial offer to supply MW and corresponding offer prices. INCs can be submitted by any market participant.
- **Up to Congestion Transaction (UTC).** Conditional transaction that permits a market participant to specify a maximum price spread for a specific amount of MW between the transaction source and sink. An up to congestion transaction is a matched pair of an injection and a withdrawal.
- **Import.** An import is an external energy transaction for a specific MW amount scheduled to PJM from another balancing authority. An import must have a valid willing to pay congestion (WPC) OASIS reservation when offered. An import energy transaction that clears the day-ahead energy market is financially binding. There is no link between transactions submitted in the PJM Day-Ahead Energy Market and the PJM Real-Time Energy Market, so an import energy transaction approved in the day-ahead energy market will not physically flow in real-time unless it is also submitted through the real-time energy market scheduling process.

PJM Day-Ahead Supply Duration

Figure 3-5 shows the distribution of the day-ahead hourly cleared supply, including increment offers, up to congestion transactions, and imports in the first three months of 2025 and 2026.

Figure 3-5 Distribution of day-ahead cleared supply plus imports: January through March, 2025 and 2026 [27]



27 Each range on the horizontal axis excludes the start value and includes the end value.

PJM Day-Ahead Average Cleared Supply

Table 3-4 presents day-ahead hourly cleared supply summary statistics for each year for the first three months of 2001 through 2026.

The day-ahead hourly average cleared supply in the first three months of 2026, including INCs and UTCs, decreased by 0.2 percent from the first three months of 2025 from 116,697 MWh to 116,436 MWh.

The day-ahead hourly average cleared supply in the first three months of 2026, including INCs, UTCs and imports, increased by 0.0 percent from the first three months of 2025, from 116,935 MWh to 116,985 MWh.

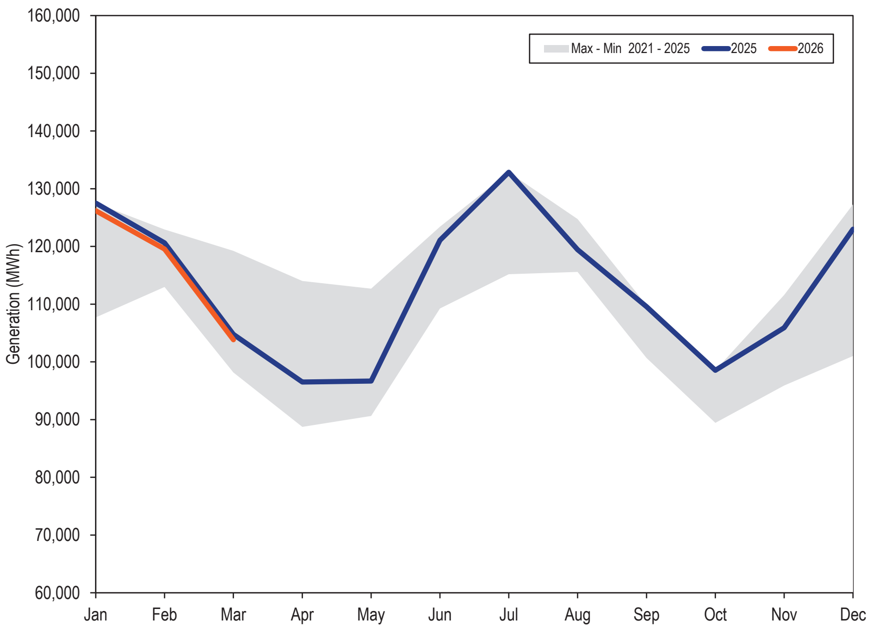
Table 3-4 Day-ahead hourly average cleared supply and cleared supply plus imports: January through March, 2001 through 2026

	PJM Day-Ahead Supply (MWh)				Year-to-Year Change			
	Supply		Supply Plus Imports		Supply		Supply Plus Imports	
Jan-Mar	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation
2001	28,494	2,941	29,252	3,021	NA	NA	NA	NA
2002	20,274	10,131	20,827	10,134	(28.8%)	244.5%	(28.8%)	235.5%
2003	37,147	4,337	37,807	4,389	83.2%	(57.2%)	81.5%	(56.7%)
2004	46,591	4,794	47,377	5,039	25.4%	10.5%	25.3%	14.8%
2005	89,011	9,434	90,502	9,443	91.0%	96.8%	91.0%	87.4%
2006	97,319	9,035	99,551	9,061	9.3%	(4.2%)	10.0%	(4.0%)
2007	110,099	11,938	112,561	12,141	13.1%	32.1%	13.1%	34.0%
2008	109,711	10,479	112,165	10,671	(0.4%)	(12.2%)	(0.4%)	(12.1%)
2009	104,880	13,895	107,325	14,031	(4.4%)	32.6%	(4.3%)	31.5%
2010	101,733	13,835	104,858	13,917	(3.0%)	(0.4%)	(2.3%)	(0.8%)
2011	110,310	12,200	112,854	12,419	8.4%	(11.8%)	7.6%	(10.8%)
2012	132,178	13,701	134,405	13,804	19.8%	12.3%	19.1%	11.2%
2013	147,246	13,054	149,300	13,244	11.4%	(4.7%)	11.1%	(4.1%)
2014	168,373	11,875	170,778	11,935	14.3%	(9.0%)	14.4%	(9.9%)
2015	123,431	14,671	125,980	14,916	(26.7%)	23.5%	(26.2%)	25.0%
2016	133,199	19,049	135,574	19,349	7.9%	29.8%	7.6%	29.7%
2017	140,771	16,923	142,094	16,938	5.7%	(11.2%)	4.8%	(12.5%)
2018	120,754	22,172	121,313	22,177	(14.2%)	31.0%	(14.6%)	30.9%
2019	122,368	13,778	122,865	13,822	1.3%	(37.9%)	1.3%	(37.7%)
2020	112,939	12,020	113,274	12,021	(7.7%)	(12.8%)	(7.8%)	(13.0%)
2021	107,588	13,940	107,851	14,003	(4.7%)	16.0%	(4.8%)	16.5%
2022	113,169	13,544	113,410	13,615	5.2%	(2.8%)	5.2%	(2.8%)
2023	121,433	11,143	122,016	11,274	7.3%	(17.7%)	7.6%	(17.2%)
2024	114,088	13,629	114,424	13,652	(6.0%)	22.3%	(6.2%)	21.1%
2025	116,697	15,116	116,935	15,136	2.3%	10.9%	2.2%	10.9%
2026	116,436	15,087	116,985	15,144	(0.2%)	(0.2%)	0.0%	0.1%

PJM Day-Ahead Monthly Average Cleared Supply

Figure 3-6 compares the day-ahead monthly average cleared supply including increment offers and up to congestion transactions in 2025 and the first three months of 2026 with the historic five year range.

Figure 3-6 Day-ahead monthly average cleared supply: 2025 through March 2026



Real-Time and Day-Ahead Supply

Table 3-5 presents summary statistics for day-ahead and real-time cleared supply in the first three months of 2025 and 2026. The last two columns of Table 3-5 are the day-ahead cleared supply minus the real-time cleared supply. The first column is the total physical day-ahead generation less the total physical real-time generation and the second column is the total day-ahead cleared supply less the total real-time cleared supply. The total real-time cleared supply includes real-time generation and real-time imports. The total day-ahead cleared supply includes physical day-ahead generation, INCs, UTCs, and day-ahead imports.

The total physical day-ahead average generation less the total physical real-time average generation in the first three months of 2026 increased 1,373 MWh from the first three months of 2025, from -1,866 MWh to -493 MWh. The total day-ahead average supply less the total real-time average supply in the first three months of 2026 decreased 2,618 MWh from the first three months of 2025, from 12,622 MWh to 10,003 MWh.

Table 3-5 Day-ahead and real-time hourly cleared supply (MWh): January through March, 2025 and 2026

		Day Ahead					Real Time		Day Ahead Less Real Time	
	Jan-Mar	Generation	INC Offers	Up to Congestion	Imports	Total Supply	Generation	Total Supply	Generation	Supply
Average	2025	100,260	6,155	10,282	238	116,935	102,126	104,313	(1,866)	12,622
	2026	103,483	5,292	7,661	550	116,985	103,976	106,982	(493)	10,003
Median	2025	98,704	5,976	10,057	182	116,225	100,668	102,752	(1,964)	13,473
	2026	101,915	5,260	7,570	526	116,855	102,050	104,853	(135)	12,002
Standard Deviation	2025	14,301	1,663	2,686	198	15,136	14,587	15,042	(285)	94
	2026	14,584	1,429	2,852	302	15,144	15,033	15,635	(449)	(491)
Peak Average	2025	105,124	6,954	11,293	255	123,626	107,192	109,330	(2,068)	14,297
	2026	107,425	5,751	8,732	584	122,491	107,880	110,834	(456)	11,657
Peak Median	2025	102,909	6,940	11,213	208	121,872	105,142	107,352	(2,233)	14,520
	2026	105,598	5,705	8,694	569	122,243	105,794	108,915	(196)	13,328
Peak Standard Deviation	2025	14,107	1,639	2,646	187	13,599	14,702	15,142	(595)	(1,543)
	2026	12,569	1,344	2,850	307	12,442	13,217	13,704	(648)	(1,263)
Off-Peak Average	2025	96,001	5,455	9,396	223	111,074	97,690	99,920	(1,689)	11,154
	2026	100,032	4,890	6,723	519	112,164	100,557	103,609	(525)	8,555
Off-Peak Median	2025	95,567	5,460	9,197	158	110,455	97,617	99,959	(2,051)	10,496
	2026	97,889	4,784	6,427	495	111,288	98,142	100,787	(252)	10,501
Off-Peak Standard Deviation	2025	13,063	1,338	2,392	205	13,941	12,955	13,507	108	434
	2026	15,338	1,380	2,504	294	15,651	15,687	16,427	(349)	(776)

Figure 3-7 shows the average cleared volumes of day-ahead and real-time supply by hour of the day in the first three months of 2025. The day-ahead cleared supply consists of cleared MW of physical generation, imports, increment offers and up to congestion transactions. The real-time cleared supply consists of cleared MW of physical generation and imports.

Figure 3-7 Day-ahead and real-time cleared supply (Average volumes by hour of the day): January through March, 2026

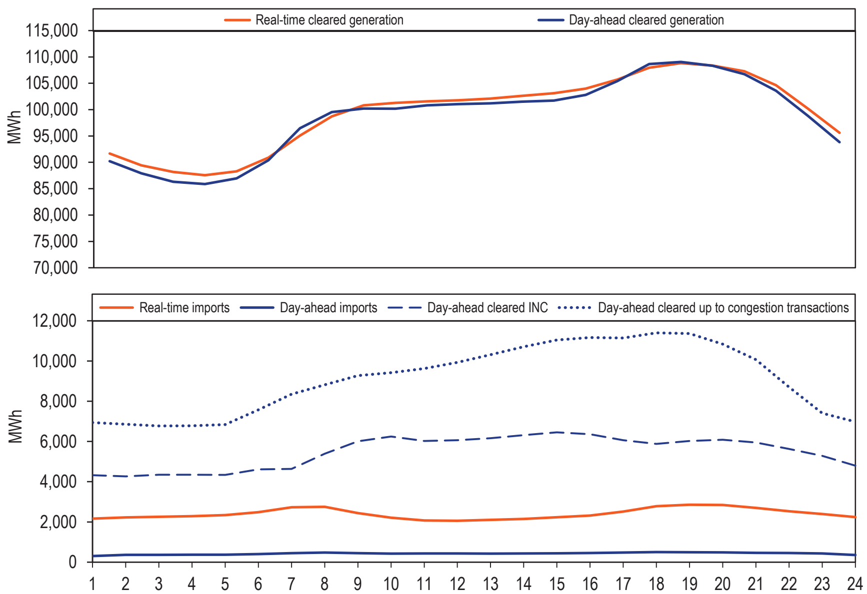
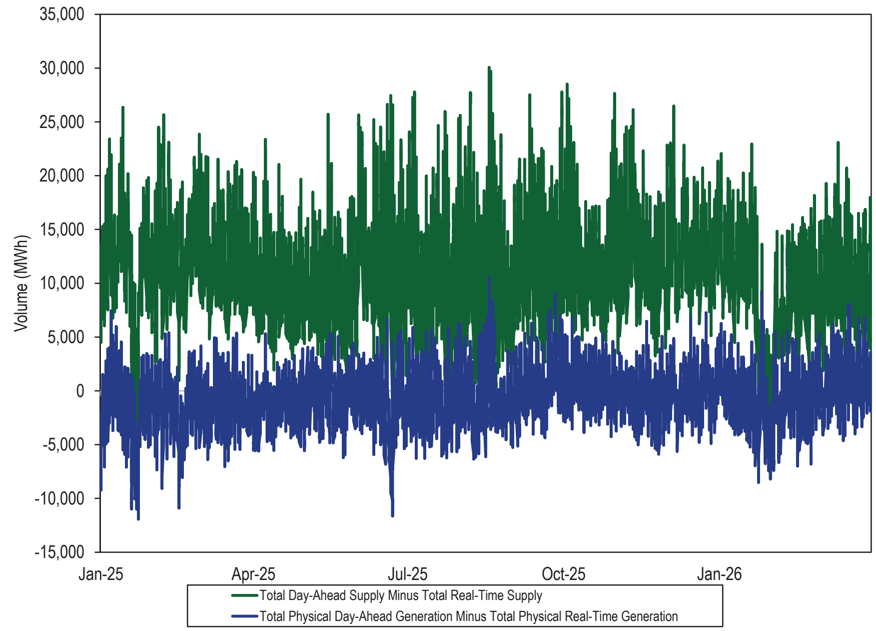


Figure 3-8 shows the difference between day-ahead and real-time daily average cleared supply in 2025 and the first three months of 2026. The blue line is the total physical day-ahead generation less the total physical real-time generation, and the green line is the total day-ahead cleared supply less the total real-time cleared supply. The total real-time cleared supply includes real-time generation and real-time imports. The total day-ahead cleared supply includes physical day-ahead generation, INCs, UTCs, and day-ahead imports.

Figure 3-8 Difference between day-ahead and real-time daily average cleared supply: 2025 through March 2026



Demand

In the real-time energy market, demand includes physical load and exports. In the day-ahead energy market, demand includes physical load, exports, and virtual transactions.

Peak Demand

In the real-time energy market, demand refers to physical accounting load and exports, and in the day-ahead energy market, demand also includes virtual demand transactions.[28]

Table 3-6 shows the seasonal peak load, net exports, real-time generation and the LMP for the peak load hour for 2004 through March 2026.

28 PJM reports peak load including accounting load plus an addback equal to PJM's estimated load drop from demand side resources. This will generally result in PJM reporting peak load values greater than accounting load values. PJM's load drop estimate is based on PJM Manual 19: Load Forecasting and Analysis," Attachment A: Load Drop Estimate Guidelines.

The winter peak load in the first three months of 2026 was 135,722 MWh in the HE 0800 (EPT) on January 29, 2026, lower than the winter peak load in the first three months of 2025, which was 140,043 MWh in the HE 0900 (EPT) on January 22, 2025.

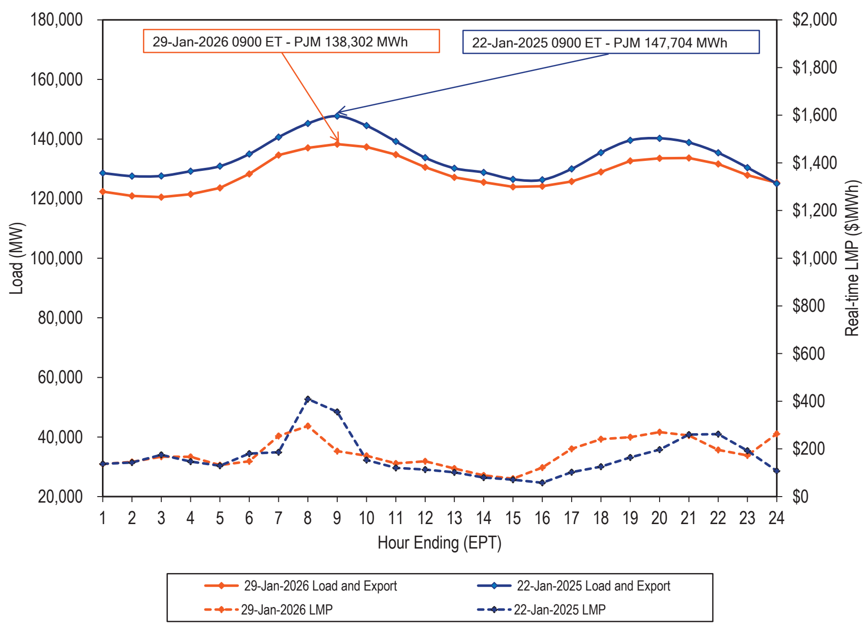
Table 3-6 Actual PJM peak load by season: 2004 through March 2026[29] [30]

	Peak Load by Season											
	Summer Peak Load Hour						Winter Peak Load Hour					
Year	Date	Hour Ending	RT Load (MWh)	Net Export (MWh)	RT Generation (MWh)	LMP ($/MWh)	Date	Hour Ending	RT Load (MWh)	Net Export (MWh)	RT Generation (MWh)	LMP ($/MWh)
2004	Tuesday, August 03, 2004	17	77,950	435	78,666	$90.55	Monday, December 20, 2004	19	96,838	1,796	98,797	$129.90
2005	Tuesday, July 26, 2005	16	134,017	(2,206)	131,975	$156.02	Wednesday, December 14, 2005	19	110,632	(376)	110,406	$163.45
2006	Wednesday, August 02, 2006	17	144,904	(782)	143,957	$404.80	Friday, December 08, 2006	19	106,866	873	108,002	$83.17
2007	Wednesday, August 08, 2007	16	136,368	404	140,170	$471.98	Monday, February 05, 2007	20	119,072	(3,964)	115,252	$178.18
2008	Monday, June 09, 2008	17	127,216	2,862	125,804	$155.67	Thursday, January 03, 2008	19	109,239	(641)	112,339	$130.11
2009	Monday, August 10, 2009	17	123,900	163	127,229	$85.64	Friday, January 16, 2009	19	114,765	(2,316)	115,093	$80.73
2010	Tuesday, July 06, 2010	17	133,297	(247)	136,442	$194.02	Tuesday, December 14, 2010	19	113,121	(1,688)	115,284	$137.02
2011	Thursday, July 21, 2011	17	154,095	(5,906)	151,790	$162.28	Monday, January 24, 2011	8	108,156	(1,218)	109,394	$176.49
2012	Tuesday, July 17, 2012	17	150,879	(4,825)	149,582	$203.72	Tuesday, January 03, 2012	19	119,450	109	122,802	$67.07
2013	Thursday, July 18, 2013	17	153,790	(7,607)	149,806	$244.92	Tuesday, January 22, 2013	19	123,473	(3,412)	123,283	$119.20
2014	Tuesday, June 17, 2014	18	138,448	(7,382)	134,914	$113.51	Tuesday, January 07, 2014	19	136,932	(9,127)	131,731	$386.36
2015	Tuesday, July 28, 2015	17	140,266	(3,942)	139,450	$101.40	Friday, February 20, 2015	8	139,647	(6,994)	137,504	$381.93
2016	Thursday, August 11, 2016	16	148,577	1,235	153,820	$128.83	Thursday, December 15, 2016	19	127,759	(2,946)	128,979	$107.06
2017	Wednesday, July 19, 2017	18	142,387	3,166	148,409	$59.49	Monday, January 09, 2017	8	124,210	(1,054)	126,761	$67.72
2018	Tuesday, August 28, 2018	17	147,042	3,238	154,067	$131.36	Friday, January 05, 2018	19	133,851	(403)	137,173	$164.15
2019	Friday, July 19, 2019	18	148,228	3,253	154,542	$37.47	Thursday, January 31, 2019	8	134,060	1,077	138,744	$85.21
2020	Monday, July 20, 2020	17	141,449	6,013	150,667	$74.91	Wednesday, January 22, 2020	8	116,761	4,230	123,609	$31.76
2021	Tuesday, August 24, 2021	17	145,563	2,984	151,708	$243.98	Friday, January 29, 2021	9	114,457	3,200	120,648	$27.87
2022	Wednesday, July 20, 2022	18	144,356	3,190	151,620	$204.29	Friday, December 23, 2022	19	131,474	3,340	136,132	$2,011.80
2023	Thursday, July 27, 2023	18	144,215	7,211	151,896	$110.52	Friday, February 03, 2023	20	117,705	746	121,952	$56.22
2024	Tuesday, July 16, 2024	18	148,890	508	152,864	$384.56	Wednesday, January 17, 2024	9	130,293	9,291	143,324	$103.66
2025	Monday, June 23, 2025	18	156,256	2,533	162,599	$273.39	Wednesday, January 22, 2025	9	140,043	7,660	151,437	$355.76
2026							Thursday, January 29, 2026	8	135,722	1,316	140,610	$295.93

29 Peak loads shown are accounting load, without losses. See the *MMU Technical Reference for the PJM Markets*, at "Load Definitions," for detailed definitions of load. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.
30 Peak loads shown have been corrected to reflect the accounting load value excluding PJM loss adjustment. The values presented in this table do not include settlement adjustments made prior to January 1, 2017

Figure 3-9 compares prices and load plus net exports on the peak load days for 2025 and 2026. The real-time average LMP for January 22, 2025, peak load hour was $107.35 per MWh, and for January 29, 2026, peak load hour it was $190.82 per MWh.

Figure 3-9 Winter peak load with net export day comparison



Real-Time Demand

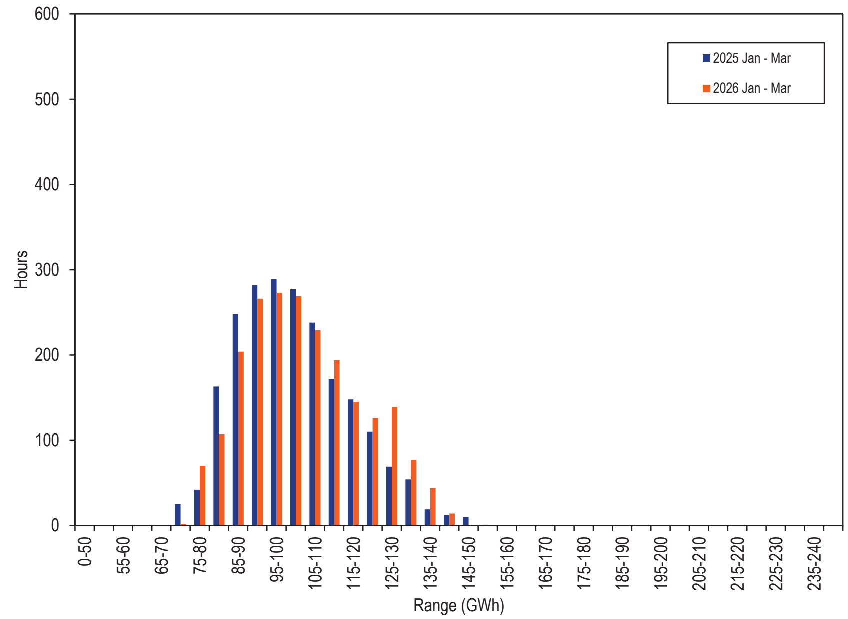
In the PJM Real-Time Energy Market, there are two types of demand:[31]

- **Load.** The actual MWh level of energy used by load within PJM.
- **Export.** An export is an external energy transaction scheduled from PJM to another balancing authority. A real-time export must have a valid OASIS reservation when offered, must have available ramp room to support the export, must be accompanied by a NERC Tag, and must pass the neighboring balancing authority's checkout process.

PJM Real-Time Demand Duration

Figure 3-10 shows the distribution of the real-time hourly load plus exports in the first three months of 2025 and 2026.[32]

Figure 3-10 Distribution of real-time load plus exports: January through March, 2025 and 2026[33]



PJM Real-Time Average Demand

Table 3-7 presents real-time hourly demand summary statistics for the first three months of 2001 through 2026.[34]

31 Load data are the net MWh injections and withdrawals MWh at every load bus in PJM.

32 All real-time load data in Section 3, "Energy Market," "Market Performance: Load and LMP," are based on PJM accounting load. See the *Technical Reference for PJM Markets*, "Load Definitions," for detailed definitions of accounting load. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

33 Each range on the horizontal axis excludes the start value and includes the end value.

34 Accounting load is used because accounting load is the load customers pay for in PJM settlements. The use of accounting load with losses before June 1, 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 incorporation of marginal loss pricing in LMP.

The real-time hourly average load in the first three months of 2026 increased by 3.1 percent from the first three months of 2025, from 95,801 MWh to 98,749 MWh. This was the highest real-time hourly average load for the first three months since the start of the PJM market.

The real-time hourly average demand including exports in the first three months of 2026 increased by 2.4 percent from the first three months of 2025, from 102,154 MWh to 104,630 MWh. This was the highest real-time hourly average demand for the first three months since the start of the PJM market.

Table 3-7 Real-time hourly average load and load plus exports: January through March, 2001 through 2026

	PJM Real-Time Demand (MW)				Year to Year Change			
	Load		Load Plus Exports		Load		Load Plus Exports	
Jan-Mar	Load	Standard Deviation	Demand	Standard Deviation	Load	Standard Deviation	Demand	Standard Deviation
2001	31,254	3,846	33,452	3,704	NA	NA	NA	NA
2002	29,968	4,083	30,988	3,932	(4.1%)	6.1%	(7.4%)	6.1%
2003	39,249	5,546	41,600	5,701	31.0%	35.8%	34.2%	45.0%
2004	39,549	5,761	41,198	5,394	0.8%	3.9%	(1.0%)	(5.4%)
2005	71,388	8,966	79,319	9,587	80.5%	55.6%	92.5%	77.8%
2006	80,179	8,977	86,567	9,378	12.3%	0.1%	9.1%	(2.2%)
2007	84,586	12,040	90,304	12,012	5.5%	34.1%	4.3%	28.1%
2008	82,235	10,184	89,092	10,621	(2.8%)	(15.4%)	(1.3%)	(11.6%)
2009	81,170	11,718	86,110	11,948	(1.3%)	15.1%	(3.3%)	12.5%
2010	81,121	10,694	86,843	11,262	(0.1%)	(8.7%)	0.9%	(5.7%)
2011	81,018	10,273	86,635	10,613	(0.1%)	(3.9%)	(0.2%)	(5.8%)
2012	86,329	10,951	91,090	11,293	6.6%	6.6%	5.1%	6.4%
2013	91,337	10,610	95,835	10,452	5.8%	(3.1%)	5.2%	(7.4%)
2014	98,317	13,484	104,454	12,843	7.6%	27.1%	9.0%	22.9%
2015	97,936	13,445	102,821	13,855	(0.4%)	(0.3%)	(1.6%)	7.9%
2016	89,322	13,262	92,777	13,409	(8.8%)	(1.4%)	(9.8%)	(3.2%)
2017	87,598	11,208	92,791	11,295	(1.9%)	(15.5%)	0.0%	(15.8%)
2018	92,761	13,244	96,216	13,487	5.9%	18.2%	3.7%	19.4%
2019	91,962	11,888	96,898	12,373	(0.9%)	(10.2%)	0.7%	(8.3%)
2020	85,608	10,004	90,093	9,736	(6.9%)	(15.8%)	(7.0%)	(21.3%)
2021	89,887	11,000	95,236	12,103	5.0%	10.0%	5.7%	24.3%
2022	92,007	11,782	98,417	11,698	2.4%	7.1%	3.3%	(3.3%)
2023	87,311	8,638	93,209	8,547	(5.1%)	(26.7%)	(5.3%)	(26.9%)
2024	89,478	11,303	95,970	11,469	2.5%	30.9%	3.0%	34.2%
2025	95,801	13,894	102,154	14,606	7.1%	22.9%	6.4%	27.3%
2026	98,749	14,619	104,630	15,160	3.1%	5.2%	2.4%	3.8%

PJM Real-Time Monthly Average Demand

Figure 3-11 compares the real-time monthly average load plus exports in 2025 and the first three months of 2026 with the historic five year range. The real-time monthly average load plus exports of January, February, and March was higher than the maximum monthly average load plus exports for the past five years.

Figure 3-11 Real-time monthly average hourly load plus exports: 2025 through March 2026

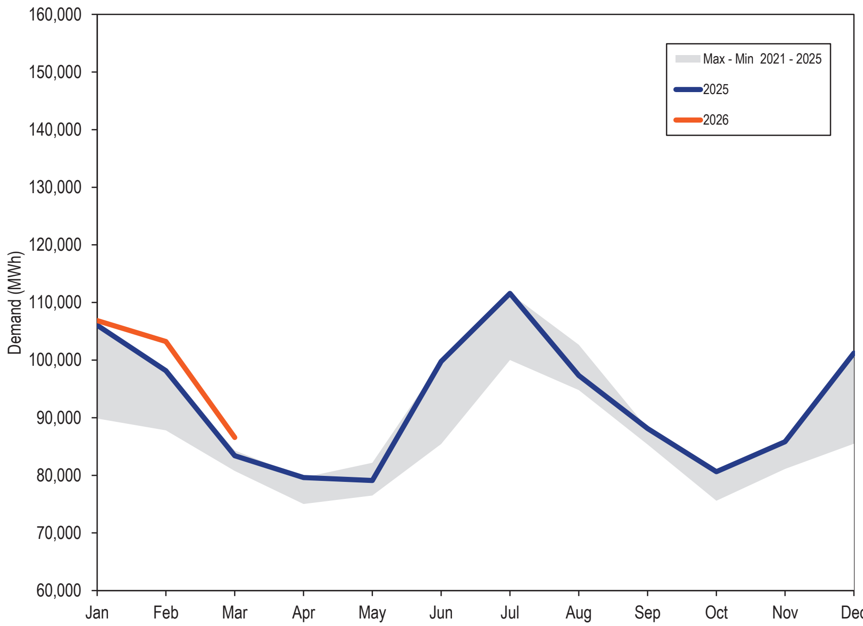
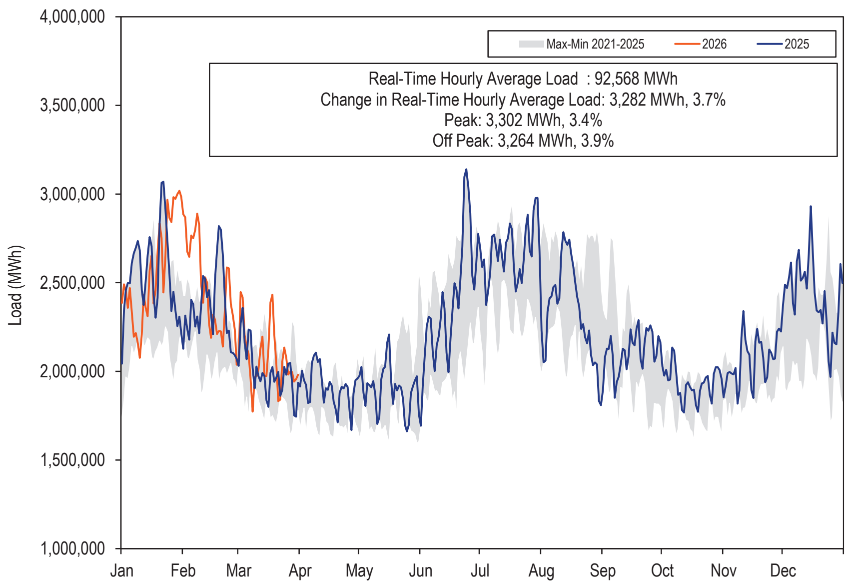


Figure 3-12 compares the real-time daily average load in 2025 and the first three months of 2026, with the historic five year range.

Figure 3-12 Real-time daily load: 2025 through March, 2026



The real-time load is significantly affected by weather conditions. Table 3-8 compares the monthly heating and cooling degree days in 2025 and the first three months of 2026.[35] Heating degree days in the first three months of 2026 increased 1.3 percent compared to the first three months of 2025.

35 A heating degree day is defined as the number of degrees that a day's average temperature is below 65 degrees F (the temperature below which buildings need to be heated). A cooling degree day is the number of degrees that a day's average temperature is above 65 degrees F (the temperature when people will start to use air conditioning to cool buildings). Reference: <https://www.eia.gov/energyexplained/units-and-calculators/degree-days.php>. This calculation was modified starting in 2024 Q3 from the method used in prior State of the Market Reports which was the PJM calculation method based on 60 degrees for heating degree days and 65 degrees for cooling degree days. Heating and cooling degree days are calculated by weighting the temperature at each weather station in the individual transmission zones using weights provided by PJM in Manual 19. Then the temperature is weighted by the real-time zonal accounting load for each transmission zone. After calculating an average hourly temperature across PJM, the heating and cooling degree formulas are used to calculate the daily heating and cooling degree days, which are summed for monthly reporting. The weather stations that provided the basis for the analysis are ABE, ACY, AVP, BWI, CAK, CLE, CMH, CRW, CVG, DAY, DCA, ERI, EWR, FWA, IAD, ILG, IPT, LEX, ORD, ORF, PHL, PIT, RIC, ROA, TOL and WAL.

Table 3-8 Heating and cooling degree days: 2025 through March 2026

	2025		2026		Percent Change	
	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days
Jan	985	0	986	0	0.1%	0.0%
Feb	720	0	750	0	4.2%	0.0%
Mar	370	2	365	4	(1.3%)	89.1%
Apr	173	10				
May	21	31				
Jun	1	302				
Jul	0	433				
Aug	0	242				
Sep	0	139				
Oct	128	15				
Nov	432	0				
Dec	837	0				
Jan-Mar	2,075	2	2,102	4	1.3%	89.1%

Day-Ahead Demand

In the PJM Day-Ahead Energy Market, there are five types of financially binding demand bids:

- **Fixed-Demand Bid.** Bid to purchase a defined MWh level of energy, regardless of LMP. Fixed-Demand Bids are included in Day-Ahead physical load.
- **Price-Sensitive Bid.** Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero. Price-Sensitive Bids are included in Day-Ahead physical load.
- **Decrement Bid (DEC).** Financial bid to purchase a defined MWh level of energy up to a specified LMP, above which the bid is zero.
- **Up to Congestion Transaction (UTC).** A conditional transaction that permits a market participant to specify a maximum price spread between the transaction source and sink. An up to congestion transaction is evaluated as a matched pair of an injection and a withdrawal.
- **Export.** An external energy transaction scheduled from PJM to another balancing authority. An export must have a valid willing to pay congestion (WPC) OASIS reservation when offered. There is no link

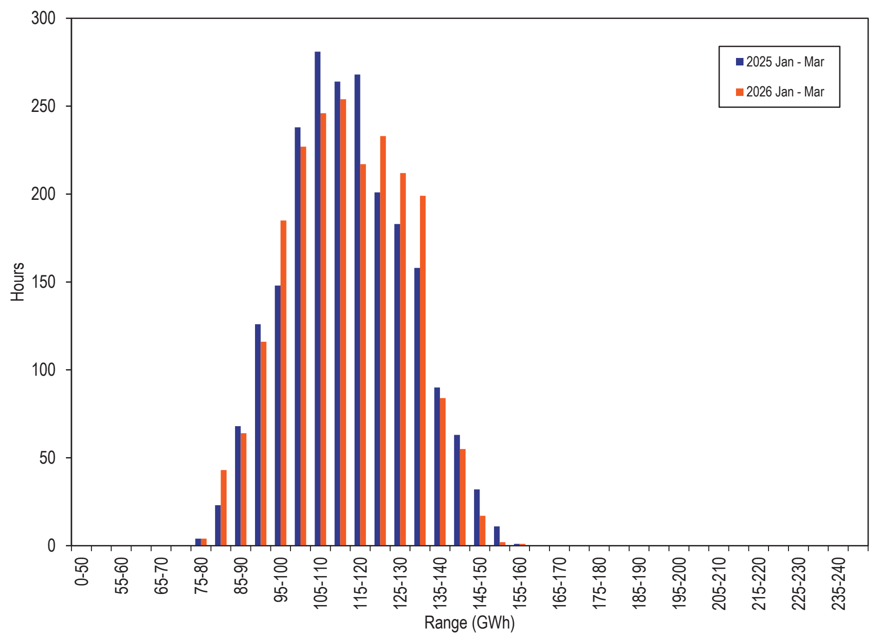
between transactions submitted in the PJM Day-Ahead Energy Market and the PJM Real-Time Energy Market, so an export energy transaction approved in the day-ahead energy market will not physically flow in real-time unless it is also submitted through the real-time energy market scheduling process.

PJM day-ahead demand is the sum of the five types of cleared demand bids.

PJM Day-Ahead Demand Duration

Figure 3-13 shows the hourly distribution of the day-ahead cleared demand including DECs, UTCs and exports in the first three months of 2025 and 2026.

Figure 3-13 Distribution of day-ahead cleared demand plus exports: January through March, 2025 and 2026[36]



PJM Day-Ahead Average Demand

Table 3-9 shows day-ahead hourly average cleared demand including DECs, UTCs and exports in 2001 through 2025.

The day-ahead hourly average cleared demand in the first three months of 2026, including DECs and UTCs, increased by 2.2 percent from the first three months of 2025, from 102,310 MWh to 104,565 MWh.

The day-ahead hourly average cleared demand in the first three months of 2026, including DECs, UTCs and exports, increased by 1.7 percent from the first three months of 2025, from 106,888 MWh to 108,703 MWh.

Table 3-9 Day-ahead hourly average cleared demand and demand plus exports: January through March, 2001 through 2026

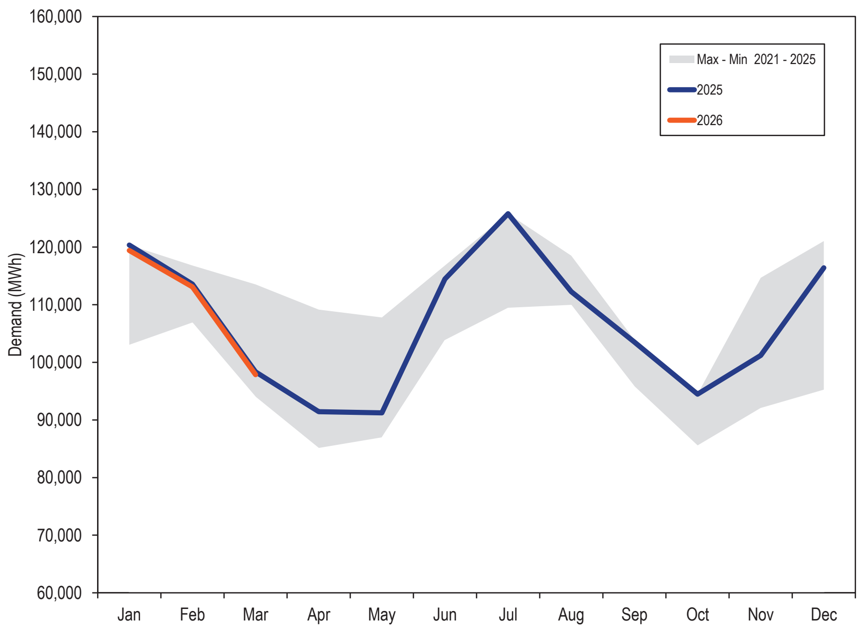
	PJM Day-Ahead Demand (MWh)				Year to Year Change			
	Demand		Demand Plus Exports		Demand		Demand Plus Exports	
Jan-Mar	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation
2001	33,731	4,557	34,523	4,390	NA	NA	NA	NA
2002	33,976	4,960	34,004	4,964	0.7%	8.8%	(1.5%)	13.1%
2003	47,034	6,841	47,147	6,853	38.4%	37.9%	38.7%	38.1%
2004	46,885	5,591	47,123	5,537	(0.3%)	(18.3%)	(0.1%)	(19.2%)
2005	87,341	9,810	90,288	9,947	86.3%	75.5%	91.6%	79.6%
2006	96,244	9,453	99,342	9,777	10.2%	(3.6%)	10.0%	(1.7%)
2007	108,699	12,601	111,831	12,746	12.9%	33.3%	12.6%	30.4%
2008	105,995	10,677	109,428	10,975	(2.5%)	(15.3%)	(2.1%)	(13.9%)
2009	102,366	13,619	105,023	13,758	(3.4%)	27.6%	(4.0%)	25.4%
2010	101,012	11,937	104,866	12,103	(1.3%)	(12.4%)	(0.1%)	(12.0%)
2011	107,116	11,890	110,865	12,157	6.0%	(0.4%)	5.7%	0.4%
2012	129,258	13,163	132,757	13,481	20.7%	10.7%	19.7%	10.9%
2013	143,585	13,120	146,878	13,108	11.1%	(0.3%)	10.6%	(2.8%)
2014	163,031	11,914	167,318	11,717	13.5%	(9.2%)	13.9%	(10.6%)
2015	119,084	14,227	123,115	14,573	(27.0%)	19.4%	(26.4%)	24.4%
2016	130,469	18,627	133,137	18,806	9.6%	30.9%	8.1%	29.0%
2017	135,574	16,264	139,299	16,454	3.9%	(12.7%)	4.6%	(12.5%)
2018	116,635	21,378	119,023	21,606	(14.0%)	31.4%	(14.6%)	31.3%
2019	117,251	13,075	120,386	13,423	0.5%	(38.8%)	1.1%	(37.9%)
2020	108,144	11,625	111,101	11,658	(7.8%)	(11.1%)	(7.7%)	(13.1%)
2021	102,372	12,828	105,639	13,599	(5.3%)	10.4%	(4.9%)	16.6%
2022	106,845	12,933	111,085	13,085	4.4%	0.8%	5.2%	(3.8%)
2023	115,558	10,827	119,435	10,914	8.2%	(16.3%)	7.5%	(16.6%)
2024	107,798	13,065	112,002	13,247	(6.7%)	20.7%	(6.2%)	21.4%
2025	110,656	14,571	115,234	14,838	2.7%	11.5%	2.9%	12.0%
2026	104,565	14,602	108,703	14,665	(5.5%)	0.2%	(5.7%)	(1.2%)

36 Each range on the horizontal axis excludes the start value and includes the end value.

PJM Day-Ahead Monthly Average Demand

Figure 3-14 compares the day-ahead monthly average cleared demand including DECs and UTCs for 2025 and the first three months of 2026, with the historic five year range.

Figure 3-14 Day-ahead monthly average cleared demand: 2025 through March 2026



Real-Time and Day-Ahead Demand

Table 3-10 presents summary statistics for day-ahead and real-time cleared demand in the first three months of 2025 and 2026. The last two columns of Table 3-10 are day-ahead cleared demand minus real-time cleared demand. The first column is the total physical day-ahead load (fixed demand plus cleared price-sensitive demand) less the physical real-time load. The second column is the total cleared day-ahead demand less the total cleared real-time demand.

The total physical day-ahead average load less the total physical real-time average load in the first three months of 2026 decreased 71 MWh from the first three months of 2025, from -1,405 MWh to -1,476 MWh. The total day-ahead average demand less the total real-time average demand in the first three months of 2026 decreased 2,678 MWh from the first three months of 2025, from 12,203 MWh to 9,525 MWh.

Table 3-10 Day-ahead and real-time demand (MWh): January through March, 2025 and 2026

		Day Ahead						Real Time		Day Ahead Less Real Time	
Jan-Mar	Year	Fixed Demand	Price Sensitive	DEC Bids	Up to Congestion	Exports	Total Demand	Load	Total Demand	Load	Demand
Average	2025	93,972	424	5,132	10,252	4,578	114,357	95,801	102,154	(1,405)	12,203
	2026	96,845	428	5,228	7,516	4,138	114,155	98,749	104,630	(1,476)	9,525
Median	2025	92,911	421	4,954	10,084	4,409	113,648	94,936	100,555	(1,604)	13,093
	2026	95,115	455	5,058	7,365	4,117	113,838	97,087	102,667	(1,517)	11,171
Standard Deviation	2025	13,303	75	1,640	2,620	1,011	14,859	13,894	14,606	(515)	253
	2026	14,406	107	1,446	2,701	795	14,825	14,619	15,160	(105)	(335)
Peak Average	2025	99,085	439	5,484	11,160	4,671	120,839	100,593	107,077	(1,069)	13,762
	2026	100,941	446	5,480	8,543	4,101	119,511	102,627	108,407	(1,240)	11,105
Peak Median	2025	97,951	442	5,233	11,138	4,465	118,992	99,320	104,985	(927)	14,007
	2026	98,770	467	5,439	8,402	4,052	119,065	100,833	106,614	(1,596)	12,451
Peak Standard Deviation	2025	12,876	75	1,640	2,531	1,064	13,405	13,731	14,690	(780)	(1,285)
	2026	12,647	110	1,524	2,697	859	12,271	12,640	13,269	117	(998)
Off-Peak Average	2025	89,494	411	4,823	9,457	4,496	108,681	91,604	97,843	(1,700)	10,838
	2026	93,258	412	5,008	6,616	4,171	109,465	95,352	101,322	(1,683)	8,142
Off-Peak Median	2025	89,644	402	4,619	9,137	4,389	108,119	92,281	97,729	(2,235)	10,390
	2026	90,695	445	4,804	6,298	4,167	108,317	92,748	98,604	(1,609)	9,713
Off-Peak Standard Deviation	2025	11,997	73	1,577	2,432	955	13,708	12,625	13,097	(555)	611
	2026	14,893	103	1,336	2,362	734	15,278	15,375	15,927	(380)	(649)

Figure 3-15 shows the average cleared volumes of day-ahead and real-time demand in for the first three months of 2026. The day-ahead demand includes day-ahead load, decrement bids, up to congestion transactions, and day-ahead exports. The real-time demand includes real-time load and real-time exports.

Figure 3-15 Day-ahead and real-time demand (Average hourly volumes): January through March, 2026

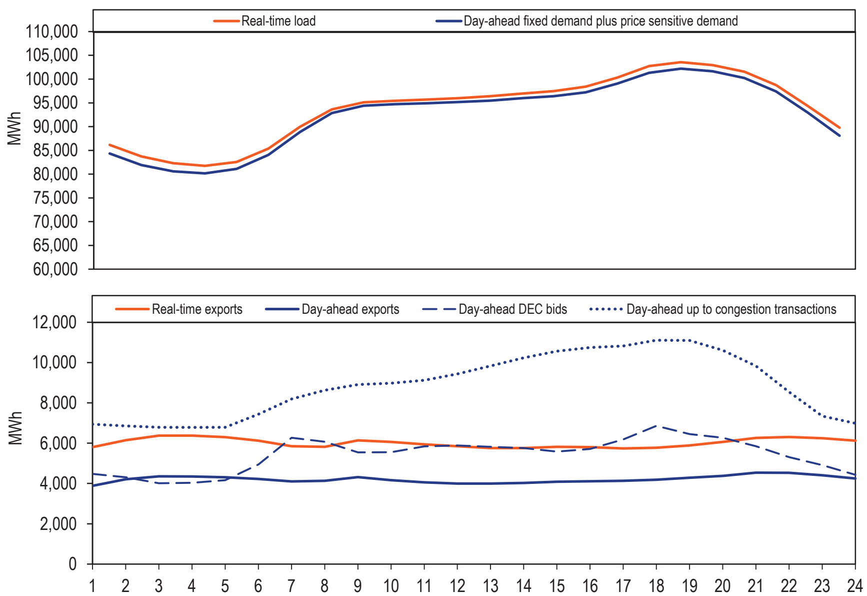
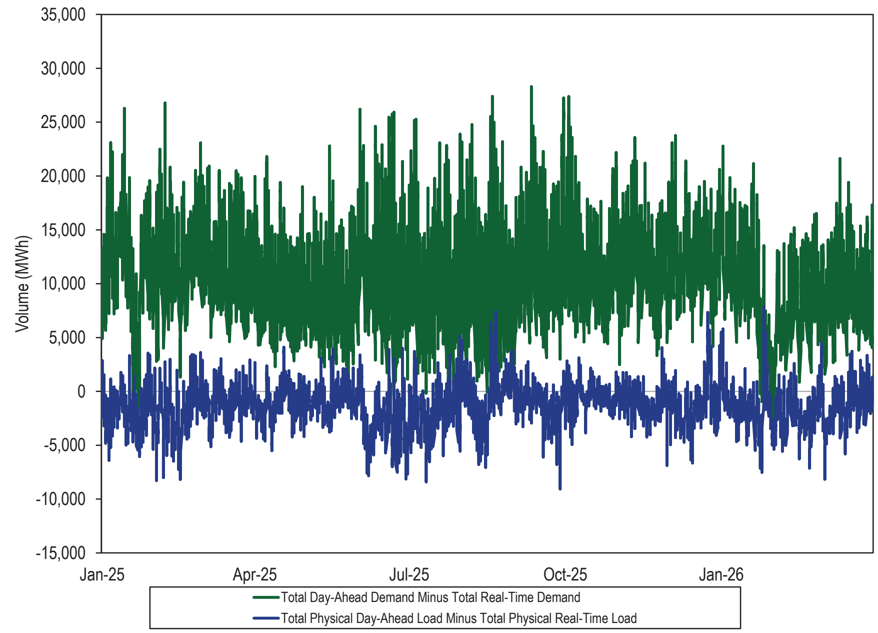


Figure 3-16 shows the difference between the physical day-ahead load and the physical real-time load, and the difference between the day-ahead demand including DECs, UTCs, and exports, and the real-time demand including exports, in 2025 through March 2026.

Figure 3-16 Day-ahead minus real-time daily demand: 2025 through March 2026



igure 3-17 shows the difference between the day-ahead and real-time hourly average load by hour of the day. DECs, UTCs and exports are not included. The largest difference generally occurs during off peak hours, especially at hours beginning 1 and 2. The smallest difference generally occurs during peak hours, especially at hours beginning 9 and 10.

Figure 3-17 Difference between day-ahead and real-time hourly average physical load by hour of the day (Average hourly volumes): January through March, 2022 through 2026

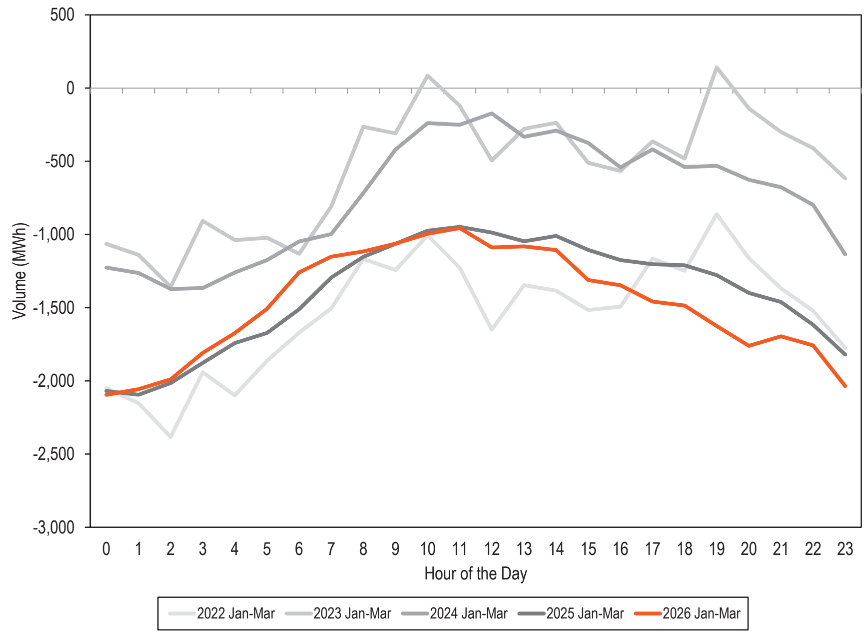


Figure 3-18 shows the difference between the day-ahead and real-time on peak and off peak hourly average physical load by month. DECs, UTCs and exports are not included.

Figure 3-18 Difference between day-ahead and real-time on peak and off peak hourly average physical load by month: 2022 through March 2026

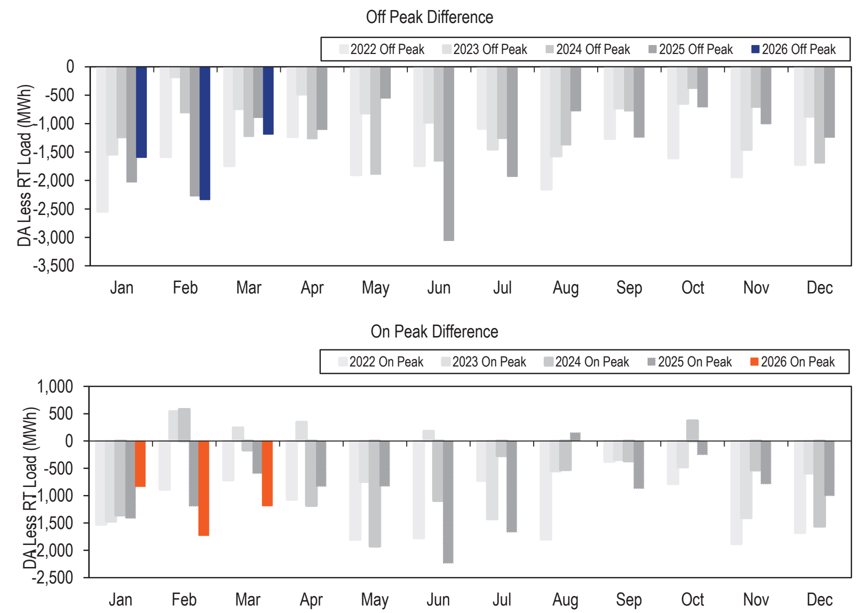


Table 3-11 shows the difference between the day-ahead and real-time on peak and off peak physical load by zone. DECs, UTCs and exports are not included. Some zones showed larger difference than other zones, such as DOM and BGE. Some zones did not show a big difference between on peak and off peak, such as DOM and AEP. Some zones showed a significant difference between on peak and off peak, such as AECO and JCPL.

Table 3-11 Difference between day-ahead and real-time on peak and off peak physical load by zone

	2025 Jan-Mar				2026 Jan-Mar			
	Off Peak		On Peak		Off Peak		On Peak	
Zone	Average DA-RT Difference	Average Percent of RT Load	Average DA-RT Difference	Average Percent of RT Load	Average DA-RT Difference	Average Percent of RT Load	Average DA-RT Difference	Average Percent of RT Load
AECO	0.24	0.7%	22.34	3.6%	8.06	1.3%	20.44	3.2%
AEP	(12.64)	0.0%	87.72	0.6%	233.10	1.4%	213.60	1.2%
APS	(131.32)	(2.1%)	(52.26)	(0.7%)	43.86	0.8%	64.09	1.0%
ATSI	(83.84)	(1.0%)	21.95	0.4%	(45.00)	(0.5%)	55.63	0.8%
BGE	(144.71)	(3.7%)	(146.66)	(3.4%)	(163.36)	(4.1%)	(152.44)	(3.7%)
COMED	(38.82)	(0.3%)	(61.34)	(0.4%)	(229.94)	(2.1%)	(170.34)	(1.3%)
DAY	(28.96)	(1.2%)	(24.62)	(0.9%)	1.02	0.3%	22.14	1.2%
DOM	(731.68)	(5.0%)	(756.42)	(4.8%)	(1,127.14)	(7.2%)	(1,157.74)	(7.3%)
DPL	(48.23)	(1.8%)	(45.74)	(1.6%)	(35.14)	(1.3%)	(4.02)	0.0%
DUQ	2.42	0.2%	29.54	2.0%	(7.41)	(0.4%)	(7.02)	(0.3%)
EKPC/DEOK	(46.22)	(0.9%)	(25.14)	(0.3%)	(4.81)	0.2%	25.90	0.8%
JCPL	(86.86)	(3.5%)	17.35	1.5%	(8.78)	0.1%	47.29	2.6%
METED	1.03	0.3%	9.79	0.7%	(42.34)	(2.4%)	(31.33)	(1.5%)
PECO	(70.04)	(1.4%)	(44.70)	(0.7%)	(176.79)	(3.6%)	(156.81)	(3.0%)
PENELEC	(13.57)	(0.6%)	4.87	0.4%	(5.65)	(0.1%)	(3.27)	0.0%
PEPCO	(110.10)	(3.2%)	(110.37)	(2.8%)	(79.26)	(2.1%)	(58.15)	(1.5%)
PPL	(13.56)	(0.0%)	43.28	1.1%	(12.49)	0.0%	4.21	0.3%
PSEG	(127.38)	(2.6%)	(24.79)	0.0%	(15.55)	0.0%	61.13	1.6%
RECO	(0.04)	0.0%	1.73	1.3%	0.30	0.3%	2.06	1.4%

Table 3-12 shows the difference between the day ahead and real-time physical load by zone for the last five years. DECs, UTCs and exports are not included. Some zones showed a change from year to year, such as AECO, PEPCO. The largest difference between day ahead physical load and real time load was in DOM with - 1,141 MW, -7.2 percent of real-time load in the first three months of 2026.

Table 3-12 Difference between day ahead and real-time physical load by zone: January through March, 2022 through 2026

	2022 Jan-Mar		2023 Jan-Mar		2024 Jan-Mar		2025 Jan-Mar		2026 Jan-Mar	
Zone	Average DA-RT Difference	Average Percent of RT Load	Average DA-RT Difference	Average Percent of RT Load	Average DA-RT Difference	Average Percent of RT Load	Average DA-RT Difference	Average Percent of RT Load	Average DA-RT Difference	Average Percent of RT Load
AECO	17.15	2.3%	14.01	2.1%	24.03	3.2%	10.56	2.0%	13.84	2.2%
AEP	(192.42)	(1.2%)	(88.81)	(0.5%)	(93.64)	(0.6%)	34.22	0.3%	224.00	1.3%
APS	(67.01)	(1.0%)	(137.20)	(2.3%)	(100.62)	(1.6%)	(94.41)	(1.4%)	53.31	0.9%
ATSI	(108.60)	(1.4%)	79.44	1.1%	8.30	0.1%	(34.45)	(0.4%)	1.98	0.1%
BGE	(108.57)	(2.8%)	(59.48)	(1.7%)	(154.31)	(4.3%)	(145.62)	(3.6%)	(158.26)	(3.9%)
COMED	(73.94)	(0.6%)	92.56	1.0%	82.88	1.0%	(49.33)	(0.4%)	(202.11)	(1.7%)
DAY	(45.15)	(2.1%)	21.09	1.2%	5.97	0.5%	(26.93)	(1.1%)	10.88	0.7%
DOM	(636.20)	(4.9%)	(631.06)	(5.0%)	(344.10)	(2.5%)	(743.23)	(4.9%)	(1,141.42)	(7.2%)
DPL	(31.01)	(1.3%)	(33.85)	(1.6%)	(5.07)	0.0%	(47.07)	(1.7%)	(20.61)	(0.7%)
DUQ	(65.87)	(4.4%)	18.62	1.4%	8.74	0.6%	15.08	1.1%	(7.23)	(0.3%)
EKPC/DEOK	(128.95)	(2.5%)	(44.93)	(0.8%)	(33.30)	(0.4%)	(36.38)	(0.6%)	9.53	0.5%
JCPL	(25.83)	(0.9%)	(14.14)	(0.3%)	14.43	1.1%	(38.21)	(1.2%)	17.40	1.2%
METED	(8.61)	(0.2%)	10.92	0.7%	22.55	1.5%	5.12	0.5%	(37.20)	(2.0%)
PECO	(8.61)	(0.0%)	101.70	2.5%	(23.82)	(0.5%)	(58.21)	(1.1%)	(167.46)	(3.4%)
PENELEC	24.03	1.2%	23.03	1.2%	8.19	0.5%	(4.96)	(0.1%)	(4.54)	(0.0%)
PEPCO	(29.22)	(0.6%)	12.79	0.6%	(133.82)	(4.1%)	(110.23)	(3.1%)	(69.40)	(1.8%)
PPL	(61.41)	(1.0%)	138.78	3.0%	67.97	1.6%	12.98	0.5%	(4.69)	0.1%
PSEG	31.00	0.7%	(46.87)	(0.9%)	(72.18)	(1.3%)	(79.49)	(1.4%)	20.25	0.8%
RECO	1.32	0.6%	3.97	2.9%	(6.47)	(4.4%)	0.78	0.6%	1.12	0.8%

Market Behavior

Generator Offers

Generators indicate their availability in the day-ahead market by submitting offers that specify a status: must-run, economic, emergency, or unavailable.

- **Must-Run:** If a unit selects must-run status, the day-ahead market will commit the unit at no less than its economic minimum MW.
- **Economic:** If a unit selects economic status, the day-ahead market will commit the unit based on the unit offers
- **Emergency:** If a unit selects emergency status, the day-ahead market will commit the unit only as needed to preserve system reliability.
- **Unavailable:** If a unit selects unavailable status, the day-ahead market will not consider the unit for commitment.

Table 3-13 shows the share of total MW offered in the day-ahead market by availability status in the first three months of 2026.

For each availability status, a unit may set its economic minimum MW equal to its economic maximum MW, termed block loading. These MW are reported in the Block Loaded column. If a unit sets its economic minimum MW below its economic maximum MW, the economic minimum MW are reported in the Eco Min column. The capacity between the economic minimum MW and the emergency maximum MW are reported in the Dispatchable column.

In the first three months of 2026, 27.0 percent of available MW were offered as must run, 54.7 percent of MW were offered as economic, 0.3 percent of MW were offered as emergency, and 18.1 percent of MW were unavailable in day-ahead market.[37]

Table 3-13 Unit Status of day-ahead energy offers: January through March, 2026

	Must Run				Economic					
Unit Type	Block Loaded	Eco Min	Dispatchable	Total	Block Loaded	Eco Min	Dispatchable	Total	Emergency	Unavailable
CC	0.2%	6.8%	6.1%	13.0%	1.1%	38.3%	32.5%	72.0%	0.0%	15.0%
CT	0.1%	0.6%	0.2%	0.9%	9.3%	45.7%	23.6%	78.6%	1.4%	19.2%
Diesel	0.0%	0.0%	0.0%	0.0%	95.3%	0.0%	0.0%	95.3%	0.9%	3.8%
Hydro	50.7%	32.8%	14.5%	98.1%	0.0%	0.0%	1.9%	1.9%	0.0%	0.0%
Nuclear	73.3%	2.0%	0.3%	75.6%	17.8%	0.0%	0.0%	17.8%	0.0%	6.7%
Other	12.2%	0.0%	3.8%	16.0%	17.7%	21.9%	28.0%	67.6%	4.0%	12.3%
Solar	10.6%	0.0%	7.5%	18.1%	0.0%	0.0%	81.9%	81.9%	0.0%	0.0%
Steam - Coal	1.5%	16.2%	10.8%	28.6%	0.8%	19.1%	18.7%	38.7%	0.0%	32.8%
Steam - Other	4.0%	4.5%	4.5%	13.0%	6.9%	14.4%	30.2%	51.5%	0.0%	35.5%
Wind	0.0%	0.4%	20.8%	21.2%	0.0%	0.1%	78.7%	78.8%	0.0%	0.0%
All Units	15.1%	6.5%	5.3%	27.0%	5.9%	25.2%	23.6%	54.7%	0.3%	18.1%

37 Unavailable MW are calculated based on the total default emergency maximum MW of all the unavailable units in day-ahead market. Wind, Solar and Hydro were set to 0 MW based on the units' technology.

Table 3-14 shows the share of total MW offered in the day-ahead market by dispatchable status in the first three months of 2026.

The Block Loaded column shows the percentage of total MW for all units that set their economic minimum MW equal to their economic maximum MW, regardless of commitment availability status. The Eco Min column shows the percentage of total MW represented by the economic minimum MW for all units that set their economic minimum MW below their economic maximum MW, regardless of commitment availability status. The Dispatchable column shows the percentage of total MW between the economic minimum MW and the economic maximum MW. The Dispatchable Range section shows the percentage of total MW offered within each price range. The Emergency column shows the percentage of total MW between the economic maximum MW and the emergency maximum MW. The numerator includes only available MW. The denominator is total available and unavailable MW. The columns for each row equal the total available percent by technology.

In the first three months of 2026, 21.1 percent of MW were offered as block loaded MW, 31.8 percent of MW were offered as economic minimum MW, 28.8 percent of MW were offered as dispatchable MW, and 0.1 percent of MW were offered as emergency MW in day-ahead market.

Table 3-14 Dispatchable status of day-ahead energy offers: January through March, 2026

		Dispatchable Percent												
Unit Type		Eco Min		Dispatchable Range										
	Block Loaded Percent		Dispatchable Percent	($300) - $0	$0 - $25	$25 - $50	$50 - $75	$75 - $100	$100 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1000	Emergency Percent
CC	1.3%	45.1%	38.6%	0.0%	21.9%	9.7%	1.8%	1.0%	2.0%	1.5%	0.3%	0.2%	0.1%	0.1%
CT	9.7%	46.9%	24.2%	0.0%	0.5%	2.9%	4.0%	2.4%	5.9%	6.5%	1.9%	0.2%	0.0%	0.1%
Diesel	96.2%	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%
Hydro	50.7%	32.8%	15.6%	14.4%	1.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Nuclear	91.1%	2.0%	0.3%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Other	34.0%	21.9%	31.7%	3.5%	0.6%	11.4%	0.9%	0.5%	0.6%	13.5%	0.3%	0.2%	0.2%	0.1%
Solar	10.6%	0.0%	89.3%	71.5%	13.4%	0.7%	0.7%	0.5%	0.7%	1.1%	0.3%	0.0%	0.3%	0.0%
Steam - Coal	2.4%	35.3%	29.5%	0.0%	4.3%	20.6%	1.7%	0.4%	0.3%	1.1%	1.1%	0.0%	0.0%	0.1%
Steam - Other	11.0%	18.9%	33.8%	2.5%	5.2%	13.2%	4.2%	2.3%	3.7%	2.5%	0.2%	0.1%	0.0%	0.9%
Wind	0.0%	0.5%	99.3%	71.7%	16.7%	4.5%	1.6%	0.7%	1.0%	1.2%	0.6%	0.0%	1.2%	0.0%
All Units	21.1%	31.8%	28.8%	3.2%	9.1%	8.8%	1.9%	1.0%	2.0%	2.0%	0.7%	0.1%	0.1%	0.1%

Hourly Offers and Intraday Offer Updates

All participants may make specific hourly offers. Hourly offers mean that participants can specify different MW and price pairs for each hour of the day. Hourly offers can be submitted in the day-ahead market and offers may be updated in the real-time market. Participants must opt in on a monthly basis to make intraday offer updates in real time. Participants that have opted in can make updates only based on the process defined in their fuel cost policies. Units typically use hourly offers to reflect the two gas days in a power day. A gas day is from 10:00 AM EPT to 10:00 AM EPT the next day. Therefore, gas fired units may face two different gas prices. Typically, gas units have one offer from 00:00 EPT until 10:00 EPT and a different offer from 10:00 EPT until 24:00 EPT. Units typically use intraday updates to reflect changes in gas costs that occur in real time.

Table 3-15 shows the daily average number of units that made hourly offers in the day-ahead market, that opted in to intraday offer updates and that made intraday offer updates. In the first three months of 2026, an average of 368 units per day made hourly offers, an increase of three units from the first three months of 2025. In the first three months of 2026, 604 units opted in for intraday offer updates, an increase of 15 units from the first three months of 2025. In the first three months of 2026, an average of 154 units made intraday offer updates each day, an increase of seven units from the first three months of 2025.

Table 3-15 Daily average number of units making hourly offers, opted in for intraday offers and making intraday offer updates: January through March, 2025 and 2026

	Fuel Type	2025 (Jan-Mar)	2026 (Jan-Mar)	Difference
Hourly Offers	Natural Gas	319	317	(2)
	Other Fuels	46	51	5
	Total	365	368	3
Opt In	Natural Gas	434	435	1
	Other Fuels	155	169	14
	Total	589	604	15
Intraday Offer Updates	Natural Gas	143	151	8
	Other Fuels	4	3	(1)
	Total	147	154	7
Total Units with nonzero offers		836	850	14

ICAP Must Offer Requirement

Generation capacity resources are required to offer their full ICAP MW into the day-ahead and real-time energy market, or report an outage for the difference.[38] The full installed capacity (ICAP) is the ICAP of the resources that cleared in the capacity market. This is known as the ICAP must offer requirement. The categorical exemption for intermittent resources, capacity storage resources, and hybrid resources from the capacity market must offer requirement was eliminated in February 2025.[39] Only demand resources are exempt from the capacity market must offer requirement.

The MMU recommends that all capacity resources have a must offer obligation. The MMU also recommends that performance penalties not be applied to solar and wind resources when they are not capable of performing based on ambient conditions. For example, solar resources should be subject to performance penalties if they fail to perform when the sun is shining but should not be subject to performance penalties in the middle of the night. This would be a rational application of the PAI penalties that recognizes the physical capabilities of resources and is therefore not discriminatory, in contrast to PJM's current treatment of such resources.

The current enforcement of the ICAP must offer requirement is inadequate.[40] The problem is a complex combination of generator behavior, and inadequate and inconsistent reporting tools that are not synchronized. Compliance is subject to mistakes and susceptible to manipulation.

Resources are required to submit their available capacity in three different systems. Resources are required to make offers in the energy market via Markets Gateway. Resources are required to report outages in the Dispatch Application Reporting Tool (eDART) in advance or in real time. Resources are required to report outages in the Generator Availability Data System (eGADS) after the fact. The three applications are not linked and there is no formal process to ensure consistency.

For example, ambient ratings are an issue. When the weather is hotter than test conditions, the capacity of some units is reduced below the ICAP levels. While this fact may be reported by unit owners in eDART and reflected in lower offered MW in the energy market, the derates are not reported as outages in eGADS and are therefore not included as outages for purposes of defining capacity using EFORd.

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.

38 OA Schedule 1 § 1.10.1A(d).

39 FERC approved extending the RPM must offer requirement to intermittent resources, capacity storage resources, and hybrid resources but not to demand resources on February 20, 2025. 190 FERC ¶ 61,117.

40 PJM compares the data submitted in eDART to the data submitted in Markets Gateway using the eDART Gen Checkout. Generators are supposed to acknowledge their Gen Checkout reports. Manual 10 and the eDART User Guide do not specify what acknowledging the Gen Checkout report means, any requirements to acknowledge the Gen Checkout report or any consequences for not doing so. Gen Checkout is also only triggered if generators fail by more than defined thresholds.

The MMU recommended that intermittent resources be subject to an enforceable ICAP must offer rule that reflects the limitations of these resources. In 2023, the MMU and PJM proposed to require intermittent resources to offer their median forecast on an hourly basis in the day-ahead and real-time energy market. This proposal was implemented on November 15, 2023.[41]

The MMU recommends that storage resources also be subject to an enforceable ICAP must offer requirement that reflects the limitations of these resources.

Table 3-16 shows average hourly MW, for each month, that violated the ICAP must offer requirement in the first three months of 2026. On average for all hours, 1,501 MW did not meet the ICAP must offer requirement, but for 10 percent of the hours, 2,720 MW did not meet the must offer requirement. These MW levels are larger than the reserve shortages that trigger scarcity pricing and larger than most supply contingencies that lead to synchronized reserve events.

Table 3-16 Average hourly estimated capacity (MW) failing the ICAP must offer requirement: January through March, 2026

Month	90th Percentile	Average	10th Percentile
Jan-26	750	412	196
Feb-26	2,006	1,542	1,190
Mar-26	2,964	2,552	2,270
2026	2,720	1,501	250

The outage data reported in eGADS do not exactly match the energy market data submitted in Markets Gateway. For example, economic maximum MW levels submitted in Markets Gateway that reflect expected ambient conditions (including ambient derates) can be inconsistent with the maximum capability submitted in eGADS. Another example is the start and end times of planned outages in the shoulder months. In many situations units are derated in Markets Gateway to reflect an upcoming planned outage for which the unit must ramp down over an extended period but in eGADS the outage start time is not reported until the unit is completely unavailable. These differences can result in units not meeting their ICAP must offer requirement.

41 *See* "Renewable Dispatch Markets Manual Changes," PJM presentation to the Markets and Reliability Committee. (November 15, 2023) <https://www.pjm.com/-/media/committees-groups/committees/mrc/2023/20231115/20231115-consent-agenda-f---1-manual-11-revisions---renewable-dispatch---presentation.ashx>.

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.

Emergency Maximum MW

Generation resources are offered with economic maximum MW and emergency maximum MW. The economic maximum MW is the output level the resource can achieve following economic dispatch. The emergency maximum MW is the output level the resource can achieve when emergency conditions are declared by PJM. The MW difference between the two ratings equals emergency maximum MW. The PJM market rules allow generators to include emergency maximum MW as part of ICAP offered in the capacity market.[42]

Generation resources have to meet one of four conditions to offer any MW as emergency in the energy market: environmental limits imposed by a federal, state or other governmental agency that significantly limit availability; fuel limits beyond the control of the generation owner; temporary emergency conditions that significantly limit availability; or temporary MW additions not ordinarily available.[43]

The MMU recommends that capacity resources not be allowed to offer any portion of their capacity market obligation as maximum emergency energy.[44] Capacity resources should offer their full output in the energy market and be subject to economic dispatch. The result will be incentives for correct reporting of ICAP, more efficient energy market pricing, and a reduction in the need for manual overrides by PJM dispatchers during emergency conditions. Resources that do have capacity that can only be achieved with extraordinary measures could offer such capacity in the energy market but should not take on a capacity market obligation.

42 See 151 FERC ¶ 61,208 at P 476 (2015).
43 OA Schedule 1 § 1.10.1A(d).
44 This recommendation was accepted by PJM and filed with FERC in 2014 as part of the capacity performance updates to the RPM. See PJM Filing, Attachment A (Redlines of OA Schedule 1 § 1.10.1A(d), EL15-29-000 (December 12, 2014). FERC rejected the proposed change. See 151 FERC ¶ 61,208 at P 476 (2015).

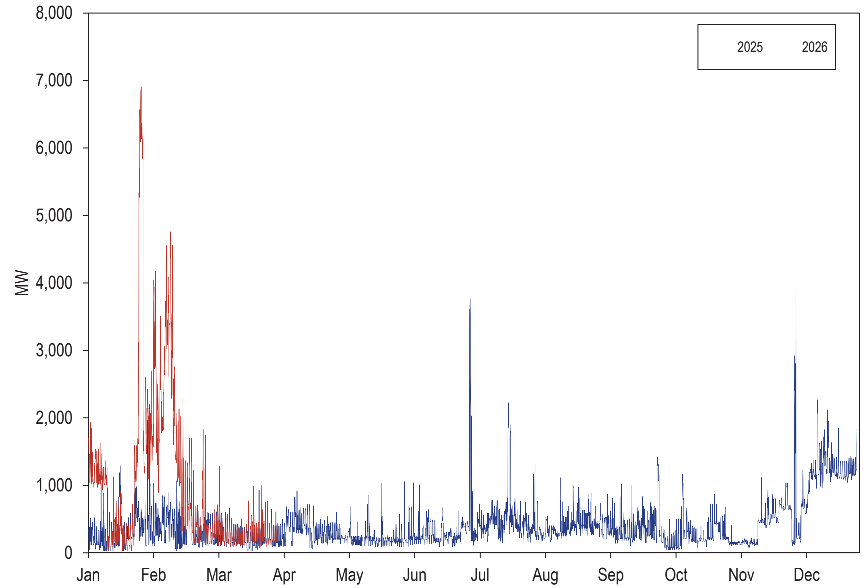
Table 3-17 shows average hourly maximum emergency MW, for each month. The levels of maximum emergency MW change hourly, daily and seasonally. For example, in February 2026, 10 percent of hours had maximum emergency MW greater than or equal to 3,380 MW while 10 percent of hours had maximum emergency MW less than 194 MW. The hourly average, in the first three months of 2026, was 977 MW offered as maximum emergency, 198.9 percent higher than in the first three months of 2025.

Table 3-17 Maximum emergency MW by month: January through March, 2026

Month	90th Percentile	Average	10th Percentile
Jan-26	2,141	1,261	116
Feb-26	3,380	1,431	194
Mar-26	470	284	129
2026	2,428	977	136

Figure 3-19 shows maximum emergency MW by hour in 2025 and the first three months of 2026. The sharp increases in maximum emergency MW typically result from short term situations at generators, such as testing of equipment which can be suspended in the event of a system emergency. The increase in December 2025 was caused by operational restrictions such as limited run hours due to environmental permits. The increases in January and February 2026 was caused mainly by oil fired units that had limited inventory remaining due to their operation during Winter Storm Fern. During Winter Storm Fern, PJM increased the criterion for maximum emergency from 16 hours to 32 hours (meaning that units could be placed in maximum emergency if their inventory fell below 32 hours of full output operation).

Figure 3-19 Maximum Emergency MW by hour: 2025 and January through March, 2026



Parameter Limited Schedules

Cost-Based Offers

All resources in PJM are required to submit at least one cost-based offer. Cost-based offers, submitted by capacity resources for a defined set of technologies, are parameter limited based on unit specific parameter limits. Nuclear, wind, solar and hydro units are not subject to parameter limits.

Price-Based Offers

All capacity resources that choose to make price-based offers are required to make available at least one price-based parameter limited offer (referred to as price-based PLS). The prices in a price-based PLS offer are at the discretion of the seller but the parameters are the same parameters used in the cost-based offers. For capacity resources, the price-based parameter limited schedule is used by PJM for committing generation resources when hot weather alerts and cold weather alerts are declared.

Offer Schedule Selection

PJM's current process for selecting unit offers (schedules) does not prevent the exercise of market power through the use of markups or through the use of inflexible parameters. The goal of having parameter limited offers is to prevent the use of inflexible operating parameters to exercise market power. Instead of ensuring that parameter limits apply, PJM chooses the lower of the price-based schedule and the price-based parameter limited schedule during hot and cold weather alerts. The goal of having cost-based offers is to prevent the use of markups to exercise market power. Instead of ensuring the least cost solution, PJM frequently chooses the higher price-based schedule that includes no parameter limits rather than the cost-based schedule that includes parameter limits when a resource fails the TPS test. The result is that PJM does not select the lowest cost schedule and allows market power to be exercised. The Commission recognized this flaw in the implementation of market power mitigation in its order to show cause, issued June 17, 2021, but did not take corrective action in its November 30, 2023 order.[45] [46]

PJM raised the schedule selection issues in the stakeholder process to address computational time in the day-ahead market. PJM's original proposal would have weakened market power mitigation. FERC rejected PJM's proposal because PJM's proposal would create the ability for market sellers to exercise market power.[47] PJM filed and, on October 25, 2024, FERC accepted a revised proposal that would require that sellers that fail the TPS test be offer capped at their cost-based offers and that operating parameters be mitigated.[48] FERC accepted PJM's proposal that has no specific plans to implement the improved rules and instead links implementation to PJM's long delayed improvements to its combined cycle modelling. PJM's revised proposal also continues to use the flawed formula, which was the basis for the first proposal rejected by FERC, to select among cost-based offers. This will result in the illogical selection of cost-based offers in some circumstances, for example 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 should be implemented as soon as possible.

The MMU analyzed the extent of parameter mitigation in the day-ahead energy market when units are committed after failing the TPS test for transmission constraints in the first three months of 2026. The analysis includes units with technologies that are subject to parameter limits and offer both price-based and cost-based schedules.[49] Table 3-18 shows the number and percentage of day-ahead unit run hours that failed the TPS test but were committed on price schedules. Table 3-18 shows that 26.2 percent of unit hours for units that failed the day-ahead TPS test were committed on price-based schedules that were less flexible than their cost-based schedules. If there were effective market power mitigation there would be zero units that fail the TPS test and are committed with parameters less flexible than their cost-based schedules.

Table 3-18 Parameter mitigation for units failing the day-ahead TPS test: January through March, 2026

Day-ahead Commitment For Units That Failed TPS Test	Day-ahead Unit Hours	Percent Day-ahead Unit Hours
Committed on price schedule less flexible than cost	9,670	26.2%
Committed on price schedule as flexible as cost	2,116	5.7%
Committed on cost (cost capped)	22,454	60.7%
Committed on price PLS	2,723	7.4%
Total committed on schedule as flexible as cost	27,293	73.8%
Total failed TPS test commitments	36,963	100.0%

The MMU analyzed the extent of parameter mitigation in the day-ahead energy market for units in zones with a cold weather alert, a hot weather alert, or a maximum generation emergency declaration in the first three

45 See 175 FERC ¶ 61,231 (2021).
46 See 185 FERC ¶ 61,158 (2023).
47 See 187 FERC ¶ 61,051 at P 25 (2024).
48 See 189 FERC ¶ 61,060 (2024).

49 Nuclear, wind, solar and hydro units are not subject to parameter limits.

months of 2026. PJM declared cold weather alerts on 16 days and hot weather alerts on 0 days in the first three months of 2026. The analysis includes units with technologies that are subject to parameter limits, with a capacity commitment, in the zones where the cold or hot weather alerts were declared. Table 3-19 shows that 25.6 percent of unit hours during weather alerts in the day-ahead energy market were committed on price-based schedules that were less flexible than their price PLS schedules. Effective market power mitigation would result in zero units committed during cold and hot weather alerts with parameters less flexible than their price PLS schedules.

Table 3-19 Parameter mitigation during weather alerts: January through March, 2026

Day-ahead Commitment During Hot And Cold Weather Alerts	Day-ahead Unit Hours	Percent Day-ahead Unit Hours
Committed on price schedule less flexible than PLS	28,174	25.6%
Committed on price schedule as flexible as PLS	14,510	13.2%
Committed on cost (cost capped)	8,629	7.8%
Committed on price PLS	58,878	53.4%
Total committed on schedule as flexible as PLS	82,017	74.4%
Total weather alert commitments	110,191	100.0%

Currently, there are no rules in the PJM tariff or manuals that limit the markup attributes of price-based PLS offers. The intent of the price-based PLS offer is to prevent the exercise of market power during high demand conditions by preventing units from offering inflexible operating parameters in order to extract higher market revenues or higher uplift payments. However, a generator can include a higher markup in the price-based PLS offer than in the price-based non-PLS schedule. The result is that the offer is higher and market prices are higher as a result of the exercise of market power using the PLS offer. This defeats the purpose of requiring price-based PLS offers.

The best solution to the use of inflexible parameters is to require the use of flexible parameters in all offers at all times for capacity resources. Capacity resources are paid to be flexible but that payment will not result in flexible offers in the energy market, the only place it matters, unless there are explicit requirements that energy offers from capacity resources incorporate that flexibility.

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.

If flexible parameters are not required at all times, the use of flexible parameters should be required whenever a unit fails the TPS test and whenever the system is facing weather alerts or emergency conditions. PJM should always use cost-based offers for units that fail the TPS test, and always use flexible parameters in all price-based offers during weather alerts and emergencies. This approach would allow PJM to effectively mitigate inflexible operating parameters consistent with PJM's asserted processing time constraints. PJM's revised schedule selection proposal adopts this approach, but PJM has failed to propose an implementation date and the flawed rules remain in place as a result.

The MMU recommends that 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 cold and hot weather alerts and emergency conditions.[50] [51]

Parameter Limits

The unit specific parameter limits for capacity resources are based on default minimum operating parameter limits posted by PJM by technology type, and any adjustments based on a unit specific review process. These default parameters were based on analysis by the MMU.

The PJM tariff specifies that all generation capacity resources, regardless of the current commitment status, are subject to parameter limits on their cost-based offers. 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.

50 *See* "Comments of the Independent Market Monitor for PJM," Docket No. EL21-78 (October 15, 2021) at 18 - 19.
51 *See* "Schedule Selection: IMM Package," IMM Presentation to the Markets Implementation Committee (September 6, 2023), <https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_MIC_Schedule_Selection_IMM_Package_20230906.pdf>.

Unit Specific Adjustment Process

Market participants can request an adjustment to the default values of parameter limits for capacity resources by submitting supporting documentation which is reviewed by PJM and the MMU. The default minimum operating parameter limits or approved adjusted values are used by capacity resources for their parameter limited schedules.

PJM has the authority to approve adjusted parameters with input from the MMU. PJM has inappropriately applied different review standards to coal units than to CTs and CCs despite the objections of the MMU. PJM has approved parameter limits for boiler based steam units based on historical performance and existing equipment while holding CTs and CCs to higher standards based on OEM documentation and a best practices equipment configuration.

The PJM process for the review of unit specific parameter limit adjustments is generally described in Manual 11: Energy and Ancillary Services Market Operations. The standards used by PJM to review the requests are currently not described in the tariff or PJM manuals. 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.

Only certain technology types are subject to limits on operating parameters in their parameter limited schedules.[52] Solar units, wind units, run of river hydro units, and nuclear units are currently not subject to parameter limits. The MMU analyzed, for the units that are subject to parameter limits, the proportion of units that use the default limits published by PJM and the proportion of units that have unit specific adjustments for some of the parameters. Table 3-20 shows, for the delivery year beginning June 1, 2025, the number of units with approved unit specific parameter limits, and the number of units that used the default parameter limits published by PJM.

52 For the default parameter limits by technology type, see PJM. "Unit-Specific Minimum Operating Parameters for Capacity Performance and Base Capacity Resources," which can be accessed at <*https://www.pjm.com/~/media/committees-groups/committees/elc/postings/20150612-june-2015-capacity-performance-parameter-limitations-informational-posting.ashx*>.

Table 3-20 Adjusted unit specific parameter limit statistics: 2025/2026 Delivery Year

Technology Classification	Units Using Default Parameter Limits	Units with One or More Adjusted Parameter Limits	Percent of Units with One or More Adjusted Parameter Limits
Aero CT	117	37	24.0%
Frame CT	149	106	41.6%
Combined Cycle	94	28	23.0%
Reciprocating Internal Combustion Engines	56	3	5.1%
Solid Fuel NUG	32	6	15.8%
Oil and Gas Steam	10	22	68.8%
Subcritical and Supercritical Coal Steam	7	64	90.1%
Total	465	266	36.4%

Parameter Limited Schedule Exceptions

There are three different types of exceptions to the parameter limited schedule default values: temporary exceptions, period exceptions, and persistent exceptions, each differentiated by the length of time it applies. Market sellers must submit requests for exceptions to PJM and the MMU for approval, along with data and documentation. Valid exceptions must be based on physical operational or contractual limits.[53]

There are no defined consequences for real-time exceptions for units that change their parameters but do not meet the requirements in the tariff. Units that override their turn down ratio (economic maximum divided by economic minimum) either use PJM's fixed gen flag or simply increase their hourly economic minimum.[54] The turn down ratio has a defined parameter limit, but the limit can be evaded by the use of the fixed gen flag. These resources override their output limit parameters with no consequence.

The MMU has proposed that such a unit should not be paid a portion of its capacity market revenues, the daily value for each day, if it fails to include its defined parameter values in its offer (by either using the fixed gen option or increasing their economic minimum). The MMU recommends that PJM

53 *See* OA Schedule 1 § 6.6(i) and PJM Manual 11, Section 2.3.4.3.

54 PJM Markets Gateway User Guide, Section 5.8: Self-schedule a Generating Unit and Ignore PJM Dispatch Instruction at 54, Section 14.3 Submit Revised MW Operating Limits at 138 and Section 14.4 Revise the Status of a Generating Unit at 139 <https://www.pjm.com/~/media/etools/markets-gateway/markets-gateway-user-guide.ashx>.

require generators to request temporary parameter exceptions for the use of the fixed gen flag. The request process requires generators to demonstrate that the request is based on a physical and actual constraint.

Consistent with the no excuses approach of the capacity performance paradigm and consistent with long term incentives for flexibility, resources that operate with a denied temporary parameter limit exception should not be paid the corresponding portion of the daily capacity value of the resource for days when it is not fully available consistent with its parameter limited schedule. If flexibility is valued as a generator attribute, the market design should not provide incentives to be inflexible. An effective market design should reward flexible operation, and ensure that capacity resources are paid for their capacity only when they meet their required level of flexibility. Without clearly defined consequences, market sellers will continue to submit inflexible parameters. The MMU recommends that resources not be paid the daily capacity payment when unable to operate to their unit specific parameter limits.[55]

Generator Flexibility Incentives in the Capacity Market

In its June 9, 2015, order on capacity performance, the Commission determined that capacity performance resources should be able to submit operating parameters to the market based not just on the resource physical constraints, but also based on other constraints, such as contractual limits.[56] The order primarily addressed limits imposed by natural gas pipelines. The Commission directed PJM to revise its tariff to establish a process through which capacity performance resources that operate outside the defined unit specific parameter limits can justify such operation and therefore remain eligible for make whole payments.[57]

A primary goal of the capacity performance market design is to assign performance risk to generation owners and to ensure that capacity prices reflect underlying supply and demand conditions, including the cost of mitigating the performance risk. The June 9th Order's determination on parameters is not consistent with that goal. By permitting generation owners to establish unit parameters based on nonphysical limits, the June 9th Order weakened the incentives for units to be flexible and weakened the assignment of performance risk to generation owners. Contractual limits and the option to choose from a range of gas pipeline tariff provisions, unlike generating unit operational limits, are a function of the interests and incentives of the generators making the choices. If a generation owner expects to be compensated through uplift payments for running for 24 hours regardless of whether the energy is economic or needed, that generation owner has no incentive to pay more to purchase the flexible gas service that would permit the unit to be flexible in response to dispatch.

The approach to parameters defined in the June 9th Order has increased energy market uplift payments substantially. While some uplift is necessary and efficient in an LMP market, this uplift is not. Electric customers are not in a position to determine the terms of the contracts that resources enter into. Customers rely on the market rules to create incentives that protect them by assigning operational risk to generators, who are in the best position to efficiently manage those risks.

The MMU recommends that capacity performance resources be held to the OEM operating parameters of the capacity market reference resource used for the Cost of New Entry (CONE) calculation for performance assessment and energy uplift payments and that this standard be applied to all technologies on a uniform basis. This solution creates the incentives for flexibility and preserves, to the extent possible, the incentives to follow PJM's dispatch instructions during high demand conditions.

Parameter Impacts of Gas Pipeline Conditions

During extreme cold weather conditions, and more recently, also during hot weather conditions, a number of gas fired generators request temporary exceptions to parameter limits for their parameter limited schedules due to restrictions imposed by natural gas pipelines. The parameters affected include notification time, minimum run time (MRT) and turn down ratio (TDR, the ratio of economic maximum MW to economic minimum MW). When pipelines

55 *See* Monitoring Analytics LLC, "Real-Time Values," presented at the Markets Implementation Committee Special Session (October 7, 2020) at 12, *which can be accessed at* <https://www.pjm.com/-/media/committees-groups/committees/mic/2020/20201007/20201007-item-06b-real-time-values-imm.ashx>.
56 See 151 FERC ¶ 61,208 at P 437 (2015).
57 *Id.* at P 440.

issue critical notices and enforce ratable take requirements, generators may, depending on the nature of the transportation service purchased, be forced to nominate an equal amount of gas for each hour in a 24 hour period, with penalties for deviating from the nominated quantity. This leads to requests for 24 hour minimum run times and turn down ratios close to 1.0, to avoid deviations from the hourly nominated quantity. The frequency of 24 hour minimum run time requests increased after Winter Storm Elliott in December 2022. Table 3-21 shows the number of units, and the installed capacity MW that submitted parameter exception requests for a 24 hour minimum run time due to gas pipeline restrictions. In the first three months of 2026, there were 97 units in PJM with a total installed capacity of 12,351 MW that requested a 24 hour minimum run time on their parameter limited schedules based on pipeline restrictions.

Table 3-21 Units with 24 hour minimum run times due to gas pipeline restrictions: January 2018 through March 2026

Year	Number of Units With 24 Hour Minimum Run Time Exceptions	Installed Capacity (MW) With 24 Hour Minimun Run Time Exceptions
2018	25	3,627
2019	37	5,616
2020	13	3,873
2021	61	7,514
2022	81	10,019
2023	75	9,824
2024	79	10,476
2025	93	11,137
2026	97	12,351

The increase in units requesting 24 hour minimum run times is a result of pipelines enforcing the pipeline tariff ratable take provisions. Pipelines have the authority to require ratable takes under their tariffs at any time although pipelines do not enforce ratable takes on a routine basis. Some generators have also requested extremely long notification times based on pipeline nomination deadlines. (See Table 3-67.) When pipelines enforce these deadlines, generators cannot obtain gas to flow for a given market hour once the deadline has passed for that hour and therefore they cannot start according to their normal notification plus start times (normally less than 30 minutes). For example, at 1700 EPT, the next nomination cycle is intraday 3 (ID3). The ID3 deadline is 2000 EPT for gas to flow starting at 2300 EPT. When these nomination deadlines are enforced, at 1700 EPT, a gas unit can only start at 2300 EPT (or in 6 hours). This effectively increases the time to start (notification time plus start time) from 30 minutes to 6 hours. The long notification times make the units unavailable for commitment in ITSCED and the units can only be committed manually in real time. Generators may request temporary exceptions based on pipeline restrictions in order to provide PJM with offers that accurately reflect their capabilities. Units operating inflexibly due to pipeline restrictions are eligible for uplift. Temporary exceptions should be limited to the duration of restrictions imposed by pipelines.

In the first three months of 2026, PJM paid $204.7 million in day-ahead uplift to gas fired units with a 24 hour minimum run time, primarily during Winter Storm Fern. PJM paid an additional $263.7 million in balancing uplift for real-time commitments of units with a 24 hour minimum run time in the first three months of 2026.

After observing the misuse of and the failure to use temporary exceptions during Winter Storm Elliott, on September 8, 2023, PJM and the MMU posted guidelines for the correct use of temporary exceptions for pipeline related restrictions. The guidelines detail exactly how units should use temporary exceptions to reflect pipeline restrictions in units' minimum run time, notification time and turn down ratio parameters.[58] During Winter Storm Elliott (December 22-24, 2022), 71 units on average (totaling 8,791 MW) requested temporary exceptions due to pipeline restrictions. During Winter Storm Gerri (January 16-18, 2024), 96 units on average (totaling 13,462 MW) requested temporary exceptions due to pipeline restrictions. During the 2025 Polar Vortex (January 18-23, 2025) 115 units on average (totaling 17,635 MW) requested exceptions due to pipeline restrictions.

The MMU recognizes that pipeline restrictions must be reflected in units' operating parameters in order for PJM to properly schedule and manage the system but it is important to prevent abuse through the submission of

58 *See* "Temporary Operating Parameter Limit (PLS) Exceptions due to Pipeline Restrictions" PJM and MMU memorandum to PJM Market Participants (September 8, 2023) <https://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Temporary_Operating_Parameter_Limit_(PLS)_Exceptions_due_to_Pipeline_Restrictions_20230908.pdf>.

inflexible parameters not based on actual constraints. The MMU recommends that PJM only approve temporary exceptions that are based on pipeline tariff terms and/or pipeline notices when actually enforced by the pipelines.

Virtual Offers and Bids

Market participants may make virtual offers and bids in the PJM Day-Ahead Energy Market, and such offers and bids may be marginal.

Any market participant in the PJM Day-Ahead Energy Market may 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. Because virtual positions do not require physical generation or load, participants must buy or sell out of their virtual positions at real-time energy market prices. On February 20, 2018, FERC issued an order limiting the eligible bidding points for up to congestion transactions to hubs, interfaces and residual aggregate metered load nodes, and limiting the eligible bidding points for INCs and DECs to the same nodes plus active generation and load nodes.[59] Up to congestion transactions may be submitted between any two aggregates on a list of 46 aggregates eligible for up to congestion transaction bidding.[60] Import and export transactions may be submitted at any interface pricing point, where an import is equivalent to a virtual offer that is injected into PJM and an export is equivalent to a virtual bid that is withdrawn from PJM.

Figure 3-20 shows an example of the PJM day-ahead daily aggregate supply curve of increment offers, the system aggregate supply curve of imports, the system aggregate supply curve without increment offers and imports, the system aggregate supply curve with increment offers, and the system aggregate supply curve with increment offers and imports for an example day in the first three months of 2026.

Figure 3-20 Day-ahead aggregate supply curves: 2026 example day

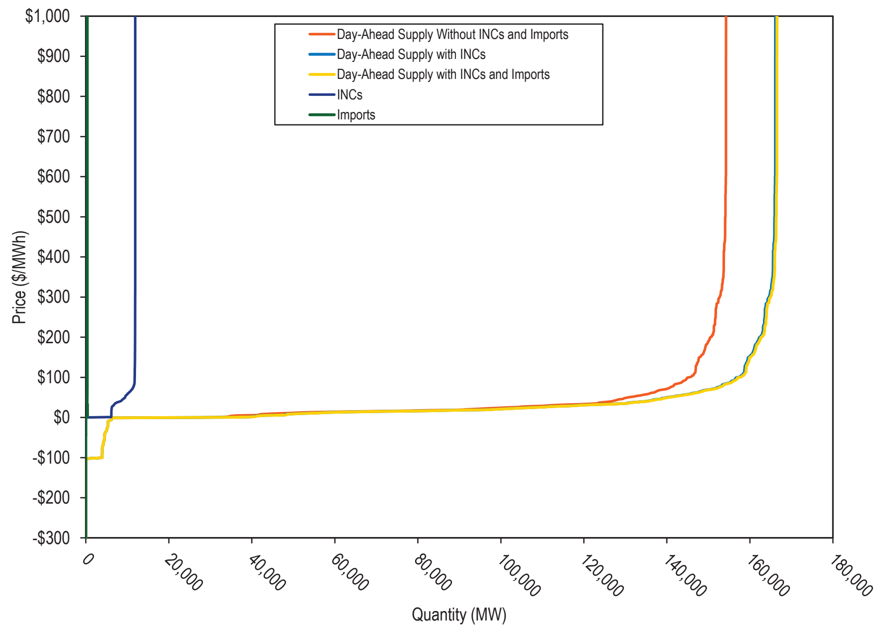


Table 3-22 shows the hourly average number of cleared and submitted increment offers and decrement bids by month in 2025 and the first three months of 2026.[61] The hourly average submitted increment offer MW decreased by 8.5 percent and cleared increment MW decreased by 14.0 percent in the first three months of 2026 compared to the first three months of 2025. The hourly average submitted decrement bid MW increased by 2.5 percent and cleared decrement MW increased by 1.9 percent in the first three months of 2026 compared to the first three months of 2025.

59 See 162 FERC ¶ 61,139 (2018), *reh'g denied*, 164 FERC ¶ 61,170 (2018).
60 Prior to November 1, 2012, market participants were required to specify an interface pricing point as the source for imports, an interface pricing point as the sink for exports or an interface pricing point as both the source and sink for transactions wheeling through PJM. For the list of eligible sources and sinks for up to congestion transactions, see www.pjm.com "*OASIS-Source-Sink-Link.xls*,"<http://www.pjm.com/~/media/etools/oasis/references/oasis-source-sink-link.ashx>.

61 Table 3-22 uses cleared day-ahead market data while final settlements data is used elsewhere in this report.

Table 3-22 Average hourly number of cleared and submitted INCs and DECs by month: January 2025 through March 2026

		Increment Offers				Decrement Bids			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2025	Jan	6,024	12,413	535	1,821	5,068	14,037	420	1,914
2025	Feb	6,207	12,420	566	1,868	5,152	14,703	444	2,089
2025	Mar	6,239	12,836	603	1,920	5,177	15,163	464	2,262
2025	Apr	6,142	12,604	584	1,679	4,343	14,247	486	2,124
2025	May	5,007	10,837	543	1,480	4,947	13,199	452	1,703
2025	Jun	4,130	10,385	466	1,435	6,310	16,189	570	2,171
2025	Jul	4,609	10,299	481	1,366	6,414	15,731	541	2,262
2025	Aug	4,694	11,329	472	1,481	6,253	14,633	502	1,821
2025	Sep	4,679	10,619	536	1,653	6,606	17,145	591	2,464
2025	Oct	6,030	11,949	636	1,885	5,103	15,481	465	2,281
2025	Nov	6,706	14,332	646	2,150	4,818	15,756	469	2,532
2025	Dec	5,956	12,815	693	2,007	5,494	16,867	550	2,665
2025	Annual	5,531	11,898	563	1,728	5,476	15,261	496	2,190
2026	Jan	5,215	11,014	631	1,706	4,986	13,413	439	2,129
2026	Feb	5,463	11,938	602	1,885	4,979	14,819	501	2,400
2026	Mar	5,214	11,562	688	1,950	5,696	16,731	606	2,616
2026	Jan-Mar	5,292	11,490	642	1,846	5,228	14,992	515	2,381

Table 3-23 shows the average hourly number of up to congestion transactions and the average hourly MW by month in 2025 and the first three months of 2026. The hourly average submitted up to congestion bid MW decreased by 20.7 percent and cleared up to congestion bid MW decreased by 25.8 percent in the first three months of 2026 compared to the first three months of 2025.

Table 3-23 Average hourly cleared and submitted up to congestion bids by month: January 2025 through March 2026

		Up to Congestion			
Year	Month	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2025	Jan	10,955	34,709	911	2,194
2025	Feb	12,000	34,801	798	2,034
2025	Mar	10,512	34,843	741	2,095
2025	Apr	8,415	29,420	610	1,999
2025	May	7,851	21,973	503	1,574
2025	Jun	11,046	32,384	791	2,071
2025	Jul	9,595	29,536	913	2,229
2025	Aug	9,019	25,911	669	1,802
2025	Sep	9,844	33,392	741	2,383
2025	Oct	9,237	38,217	660	2,624
2025	Nov	11,445	38,188	764	2,769
2025	Dec	10,808	34,726	853	2,721
2025	Annual	10,043	32,311	746	2,208
2026	Jan	9,525	31,204	798	2,791
2026	Feb	7,617	24,926	838	2,600
2026	Mar	7,556	26,358	652	2,029
2026	Jan-Mar	8,254	27,582	760	2,469

Table 3-24 shows the average hourly number of day-ahead import/export transactions and the average hourly MW in 2025 and the first three months of 2026.[62] In the first three months of 2026, the average hourly submitted import transaction MW increased by 92.0 percent and the average hourly cleared import transaction MW increased by 124.0 percent compared to the first three months of 2025. In the first three months of 2026, the average hourly submitted export transaction MW decreased by 10.8 percent and the average hourly cleared export transaction MW decreased by 9.6 percent compared to the first three months of 2025.

62 Table 3-24 uses cleared day-ahead market data, while final settlements data is used elsewhere in this report.

Table 3-24 Hourly average day-ahead number of cleared and submitted import and export transactions by month: January 2025 through March 2026

		Up to Congestion			
Year	Month	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2025	Jan	10,955	34,709	911	2,194
2025	Feb	12,000	34,801	798	2,034
2025	Mar	10,512	34,843	741	2,095
2025	Apr	8,415	29,420	610	1,999
2025	May	7,851	21,973	503	1,574
2025	Jun	11,046	32,384	791	2,071
2025	Jul	9,595	29,536	913	2,229
2025	Aug	9,019	25,911	669	1,802
2025	Sep	9,844	33,392	741	2,383
2025	Oct	9,237	38,217	660	2,624
2025	Nov	11,445	38,188	764	2,769
2025	Dec	10,808	34,726	853	2,721
2025	Annual	10,043	32,311	746	2,208
2026	Jan	9,525	31,204	798	2,791
2026	Feb	7,617	24,926	838	2,600
2026	Mar	7,556	26,358	652	2,029
2026	Jan-Mar	8,254	27,582	760	2,469

Figure 3-21 shows the monthly volume of bid and cleared INC, DEC and up to congestion bids by month from 2005 through the first three months of 2026. Cleared volumes were greater in 2023 than any year since 2020, when uplift charges for up to congestion transactions took effect on November 1, 2020. The monthly MW volume of UTC bids in April 2023 was at its highest level since 2017, but decreased significantly beginning May 2023 and has remained stable beginning August 2023 through March 2026.

Figure 3-21 Monthly bid and cleared INCs, DECs and UTCs (GWh): January 2005 through March 2026

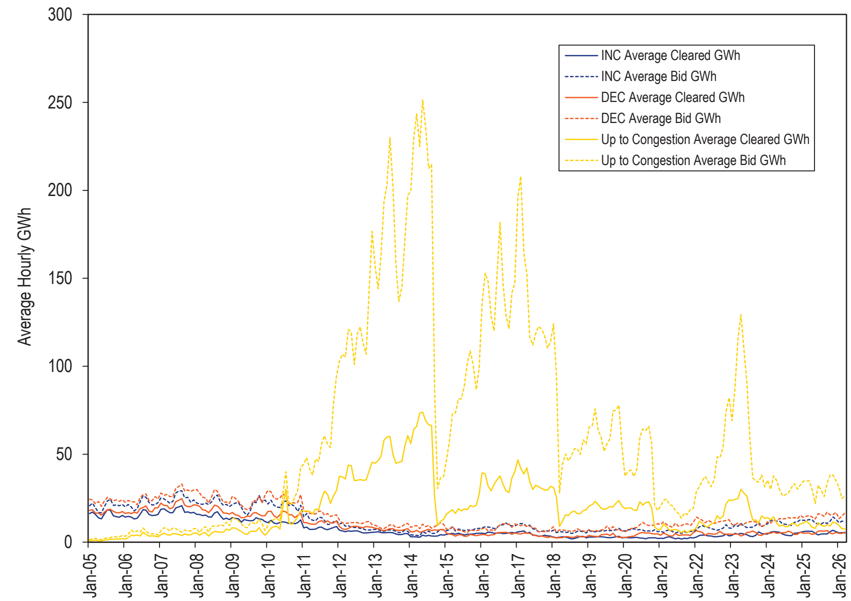
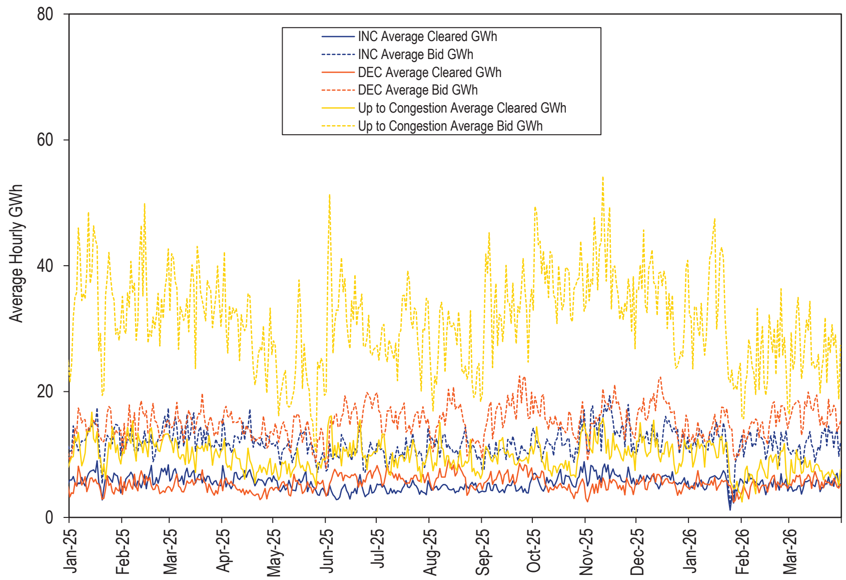


Figure 3-22 shows the daily volume of bid and cleared INC, DEC and up to congestion bids from January 2025 through March 2026.

Figure 3-22 Daily bid and cleared INCs, DECs, and UTCs (GWh): January 2025 through March 2026



In order to evaluate the ownership of virtual bids, the MMU categorizes all participants making virtual bids in PJM as either physical or financial at an account level.[63] Physical entities are defined as individual accounts in PJM's settlement systems that take physical positions in PJM markets and typically include utilities and customers. Financial entities are defined as individual accounts in PJM's settlement systems that take financial positions in PJM markets and typically include banks and trading firms. International market participants that primarily take financial positions in PJM markets are generally considered to be financial entities even if they are utilities in their own countries. Financial entities' share of cleared MWh of INCs and DECs in the first three months of 2026 decreased to 96.0 percent from 97.2 percent in the first three months of 2025.

Table 3-25 shows, in the first three months of 2025 and 2026, the total increment offers and decrement bids and cleared MW by organization type.

Table 3-25 INC and DEC bids and cleared MWh by organization type (MWh): January through March, 2025 and 2026

	2025 (Jan-Mar)				2026 (Jan-Mar)			
Category	Total Virtual Bid MWh	Percent	Total Virtual Cleared MWh	Percent	Total Virtual Bid MWh	Percent	Total Virtual Cleared MWh	Percent
Financial	57,798,549	98.4%	23,683,831	97.2%	55,948,018	97.9%	21,814,389	96.0%
Physical	910,127	1.6%	684,340	2.8%	1,226,883	2.1%	898,257	4.0%
Total	58,708,676	100.0%	24,368,171	100.0%	57,174,901	100.0%	22,712,646	100.0%

63 The MMU modified the method for categorizing participants as physical and financial participants. See the explanation in the *2025 Quarterly State of the Market Report for PJM: January through March*, Section 13: Financial Transmission Rights at Market Structure (May 8, 2025).

Table 3-26 shows the total up to congestion bid and cleared MWh by organization type in the first three months of 2025 and 2026. Up to congestion bids submitted by financial entities decreased in the first three months of 2026 compared to the first three months of 2025, from 73.3 million MWh to 57.7 million MWh, while up to congestion bids submitted by physical entities remained constant at 1.8 MWh. Financial entities submitted 97.0 percent of all up to congestion bids, down from 97.6 percent, and cleared 94.5 percent of all up to congestion bids, down from 95.2 percent. In the first three months of 2026, almost all up to congestion trading activity was by financial participants, however their submitted volumes decreased by 21.2 percent.

Table 3-26 Up to congestion transactions by organization type (MWh): January through March, 2025 and 2026

Year	Category	Total Up to Congestion Bid MWh	Percent	Total Up to Congestion Cleared MWh	Percent
	Financial	73,297,709	97.6%	22,862,889	95.2%
2025 (Jan-Mar)	Physical	1,800,257	2.4%	1,161,919	4.8%
	Total	75,097,966	100.0%	24,024,808	100.0%
	Financial	57,743,027	97.0%	16,830,971	94.5%
2026 (Jan-Mar)	Physical	1,806,876	3.0%	988,768	5.5%
	Total	59,549,903	100.0%	17,819,739	100.0%
	Financial	(15,554,682)	(21.2%)	(6,031,918)	(26.4%)
(2026 minus 2025)	Physical	6,618	0.4%	(173,151)	(14.9%)
	Difference	(15,548,063)	(20.7%)	(6,205,069)	(25.8%)

Table 3-27 shows the total import and export transactions by organization type in the first three months of 2025 and 2026.

Table 3-27 Import and export transactions by organization type (MWh): January through March, 2025 and 2026

		2025 (Jan-Mar)		2026 (Jan-Mar)	
	Category	Total Import and Export MWh	Percent	Total Import and Export MWh	Percent
Day-Ahead	Financial	5,307,102	51.0%	5,040,344	49.8%
	Physical	5,089,536	49.0%	5,080,999	50.2%
	Total	10,396,638	100.0%	10,121,344	100.0%
Real-Time	Financial	9,567,370	51.9%	11,529,740	60.1%
	Physical	8,875,828	48.1%	7,662,128	39.9%
	Total	18,443,198	100.0%	19,191,868	100.0%

Table 3-28 shows the top 10 locations by total cleared INC and DEC MWh in the first three months of 2025 and 2026. The top 10 locations included three hubs, five interface pricing points, and two residual metered load aggregates. For generator pnodes with elevated volumes that do not make the top 10 by total INC plus DEC volume, 955 RIVE16 KV RV-1 cleared the most INC volume of 202,656 MWh and ASYLUM 23 KV LIBRTY10 the most DEC volume of 167,607 MWh in the first three months of 2026.

Table 3-28 Virtual offers and bids by top 10 locations (MWh): January through March, 2025 and 2026

2025 (Jan-Mar)					2026 (Jan-Mar)				
Aggregate/Bus Name	Aggregate/Bus Type	INC MWh	DEC MWh	Total MWh	Aggregate/Bus Name	Aggregate/Bus Type	INC MWh	DEC MWh	Total MWh
WESTERN HUB	HUB	882,514	603,394	1,485,908	SOUTH	INTERFACE	1,884,014	197,531	2,081,546
SOUTH	INTERFACE	872,130	303,412	1,175,541	WESTERN HUB	HUB	529,302	980,251	1,509,553
MISO	INTERFACE	85,576	876,155	961,732	N ILLINOIS HUB	HUB	613,412	448,954	1,062,366
N ILLINOIS HUB	HUB	624,186	85,745	709,931	MISO	INTERFACE	316,903	654,995	971,898
NYIS	INTERFACE	220,084	390,731	610,815	NYIS	INTERFACE	167,916	600,897	768,813
AEP-DAYTON HUB	HUB	285,723	261,749	547,472	AEP-DAYTON HUB	HUB	307,844	249,862	557,705
DOM_RESID_AGG	RESIDUAL METERED EDC	104,426	349,295	453,721	LINDENVFT	INTERFACE	9,818	402,051	411,869
LINDENVFT	INTERFACE	25,142	412,111	437,253	DOM_RESID_AGG	RESIDUAL METERED EDC	79,579	248,771	328,350
BGE_RESID_AGG	RESIDUAL METERED EDC	173,018	206,091	379,109	BGE_RESID_AGG	RESIDUAL METERED EDC	121,644	204,352	325,996
CHICAGO HUB	HUB	193,664	179,209	372,873	IMO	INTERFACE	224,844	72,471	297,315
Top ten total		3,466,463	3,667,892	7,134,356			4,255,275	4,060,136	8,315,411
PJM total		13,288,551	11,079,620	24,368,171			11,424,528	11,288,117	22,712,646
Top ten total as percent of PJM total		26.1%	33.1%	29.3%			37.2%	36.0%	36.6%

Table 3-29 shows up to congestion transactions for the top 10 source and sink pairs and associated source, sink and overall profits on each path in the first three months of 2025 and 2026. Total profits for up to congestion transactions in the first three months of 2026 were $25.8 million, a 13.3 percent decrease compared to profits of $29.8 million in the first three months of 2025.[64] The UTCs from DOMINION HUB to DOM_RESID_AGG constituted 9.7 percent of all UTC cleared volume in the first three months of 2026, yielding a loss of $0.6 million.

64 The source and sink aggregates in these tables refer to the name and location of a bus and do not include information about the behavior of any individual market participant.

Table 3-29 Cleared up to congestion bids by top 10 source and sink pairs (MWh): January through March, 2025 and 2026

2025 (Jan-Mar)							
Top 10 Paths by Cleared MWh							
Source	Source Type	Sink	Sink Type	Cleared MW	Source Revenue	Sink Revenue	UTC Profit
DOMINION HUB	HUB	DOM_RESID_AGG	AGGREGATE	1,722,902	($2,617,180)	$7,447,303	$4,036,198
CHICAGO GEN HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	844,580	$3,531,441	($977,979)	$1,637,670
AEP GEN HUB	HUB	AEPAPCO_RESID_AGG	AGGREGATE	489,006	$4,546,648	($1,161,570)	$2,371,837
CHICAGO GEN HUB	HUB	CHICAGO HUB	HUB	426,431	$1,434,856	($1,445,801)	($277,137)
SOUTH	INTERFACE	AEPAPCO_RESID_AGG	AGGREGATE	322,485	$695,005	($2)	$355,376
AEP GEN HUB	HUB	DOMINION HUB	HUB	287,023	$976,824	$158,723	$832,268
JCPL_RESID_AGG	AGGREGATE	PSEG_RESID_AGG	AGGREGATE	263,067	($224,159)	$456,677	$118,729
AEP GEN HUB	HUB	DOM_RESID_AGG	AGGREGATE	246,496	$643,582	$982,367	$1,396,630
PECO_RESID_AGG	AGGREGATE	BGE_RESID_AGG	AGGREGATE	239,817	($483,883)	$804,853	$158,288
AEP GEN HUB	HUB	AEPOHIO_RESID_AGG	AGGREGATE	237,833	$714,891	($520,476)	($58,024)
Top ten total				5,079,641	$9,218,024	$5,744,096	$10,571,834
PJM total				24,024,808	$50,250,175	$2,629,611	$29,750,330
Top ten total as percent of PJM total				21.1%	18.3%	218.4%	35.5%
2026 (Jan-Mar)							
Top 10 Paths by Cleared MWh							
Source	Source Type	Sink	Sink Type	Cleared MWh	Source Revenue	Sink Revenue	UTC Profit
DOMINION HUB	HUB	DOM_RESID_AGG	AGGREGATE	1,731,411	$611,827	$194,717	($605,450)
CHICAGO GEN HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	435,105	$7,500,431	($4,526,111)	$1,856,460
ATSI GEN HUB	HUB	DUQ_RESID_AGG	AGGREGATE	415,507	($872,340)	$2,057,539	$734,234
CHICAGO GEN HUB	HUB	MISO	INTERFACE	341,689	$6,012,322	($3,887,688)	$809,819
SOUTH	INTERFACE	AEPAPCO_RESID_AGG	AGGREGATE	326,922	$1,837,548	$1,324,615	$2,756,494
AEP GEN HUB	HUB	AEPOHIO_RESID_AGG	AGGREGATE	257,822	$1,828,449	($1,784,484)	($324,260)
NEW JERSEY HUB	HUB	PSEG_RESID_AGG	AGGREGATE	221,108	$175,982	($165,192)	($331,516)
JCPL_RESID_AGG	AGGREGATE	PSEG_RESID_AGG	AGGREGATE	217,918	($451,389)	$488,825	($222,376)
AEPKY_RESID_AGG	AGGREGATE	AEPAPCO_RESID_AGG	AGGREGATE	209,520	$4,340,225	($2,148,037)	$908,489
COMED_RESID_AGG	AGGREGATE	AEPIM_RESID_AGG	AGGREGATE	184,505	$10,667,661	($6,944,326)	$2,855,357
Top ten total				4,341,506	$31,650,716	($15,390,144)	$8,437,250
PJM total				17,819,739	$105,079,563	($43,031,506)	$25,787,042
Top ten total as percent of PJM total				24.4%	30.1%	35.8%	32.7%

Table 3-30 shows the average daily number of distinct source-sink pairs that were offered and cleared each month from January 2025 through March 2026. The average number of submitted source-sink pairs per day increased from 1,464 source-sink pairs submitted in the first three months of 2025 to 1,490 in the first three months of 2026. The average number of cleared source-sink pairs per day decreased from 1,226 in the first three months of 2025 to 1,170 per day in the first three months of 2026.

Table 3-30 Number of offered and cleared UTC source and sink pairs: January 2025 through March 2026

		Daily Number of Source-Sink Pairs			
Year	Month	Average Offered	Max Offered	Average Cleared	Max Cleared
2025	Jan	1,454	1,641	1,222	1,490
2025	Feb	1,411	1,617	1,174	1,399
2025	Mar	1,523	1,844	1,278	1,641
2025	Apr	1,477	1,718	1,123	1,428
2025	May	1,360	1,597	938	1,325
2025	Jun	1,521	1,847	1,208	1,622
2025	Jul	1,680	1,852	1,380	1,654
2025	Aug	1,572	1,836	1,249	1,554
2025	Sep	1,554	1,766	1,257	1,497
2025	Oct	1,520	1,674	1,168	1,430
2025	Nov	1,614	1,856	1,215	1,536
2025	Dec	1,560	1,804	1,224	1,474
2025	Annual	1,520	1,754	1,203	1,504
2026	Jan	1,477	1,712	1,118	1,521
2026	Feb	1,462	1,748	1,170	1,620
2026	Mar	1,531	1,701	1,222	1,456
2026	(Jan-Mar)	1,490	1,720	1,170	1,532

Table 3-31 and Figure 3-23 show total cleared up to congestion transactions and the share of the top 10 up to congestion paths by transaction type (import, export, wheel, or internal) in the first three months of 2025 and 2026. Total cleared up to congestion transactions decreased by 25.8 percent from 24.0 million MWh in the first three months of 2025 to 17.8 million MWh in the first three months of 2026. Internal up to congestion transactions in the first three months of 2026 were 81.6 percent of all up to congestion transactions, a decrease from 82.8 percent in the first three months of 2025.

Table 3-31 Cleared up to congestion transactions and share of top 10 paths by type (MW): January through March, 2025 and 2026

	2025 (Jan-Mar)				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	1,174,791	723,195	339,179	4,993,208	7,230,372
PJM total (MW)	1,891,502	1,826,323	405,502	19,901,481	24,024,808
Top ten total as percent of PJM total	62.1%	39.6%	83.6%	25.1%	30.1%
PJM total as percent of all up to congestion transactions	7.9%	7.6%	1.7%	82.8%	100.0%
	2026 (Jan-Mar)				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	959,960	750,161	362,123	4,028,184	6,100,427
PJM total (MW)	1,593,438	1,279,916	412,231	14,534,155	17,819,739
Top ten total as percent of PJM total	60.2%	58.6%	87.8%	27.7%	34.2%
PJM total as percent of all up to congestion transactions	8.9%	7.2%	2.3%	81.6%	100.0%

Figure 3-23 shows the total volume of import, export, wheel, and internal up to congestion transactions by month from January 2005 through March 2026. An initial increase and continued increase in internal up to congestion transactions by month followed the November 1, 2012, rule change permitting such transactions, until September 8, 2014. The reduction in up to congestion transactions (UTC) that followed a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs, was reversed.[65] There was an increase in up to congestion volume as a result of the expiration of the 15 month refund period for the proceeding related to uplift charges for UTC transactions. In 2018, total UTC activity and the percent of marginal up to congestion transactions again decreased significantly as the result of a FERC order issued on February 20, 2018, and implemented on February 22, 2018.[66] The order limited UTC trading to hubs, residual metered load, and interfaces. UTC activity increased following that reduction.

UTC activity decreased again beginning November 1, 2020, after a FERC order requiring UTCs to pay day-ahead and balancing operating reserve charges equivalent to a DEC at the UTC sink point became effective on that date.[67] In 2022 and the first six months of 2023, the volume of cleared UTCs increased

65 See 162 FERC ¶ 61,139 (2018), *reh'g denied*, 164 FERC ¶ 61,170 (2018).
66 *Id.*
67 See 172 FERC ¶ 61,046 (2020).

significantly, primarily internal transactions. The volume of cleared UTCs decreased consistently from July 2023 through March 2026.

Figure 3-23 Monthly cleared up to congestion transactions by type (GWh): January 2005 through March 2026

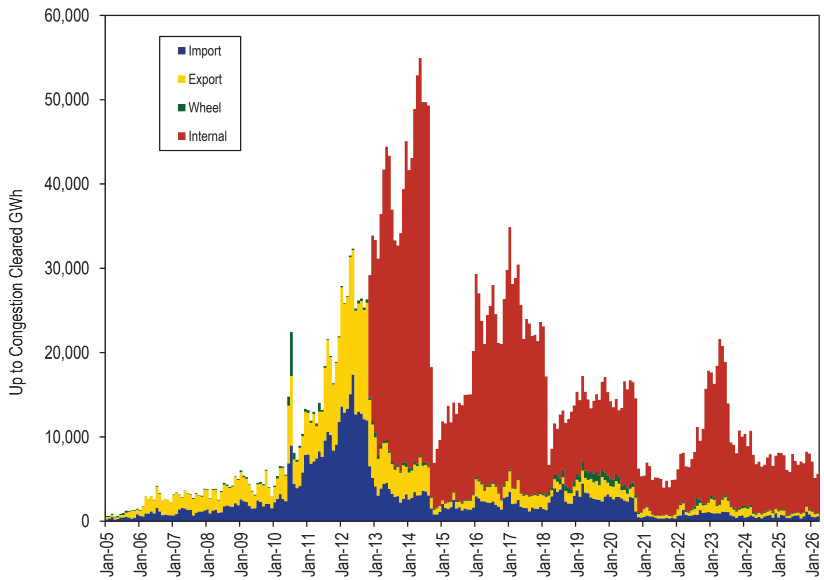
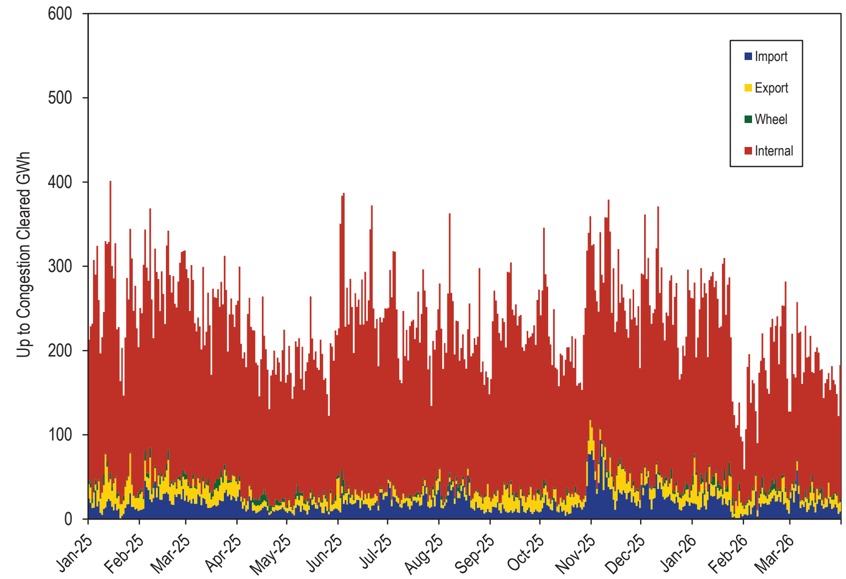


Figure 3-24 shows the daily cleared up to congestion GWh by transaction type from January 1, 2025, through March 31, 2026. In the first three months of 2026, the total cleared GWh of import, export, and internal up to congestion transactions decreased significantly compared to the first three months of 2025, primarily during Winter Storm Fern.

Figure 3-24 Daily cleared up to congestion transaction by type (GWh): January 2025 through March 2026



One of the goals of the February 2018 FERC order accepting PJM's proposal limiting UTC bidding to hubs, interfaces and residual aggregate metered load nodes, and limiting INC and DEC bidding to the same nodes plus active generation nodes, was to limit the opportunities for traders to profit from opportunities for false arbitrage in which price spreads between the day-ahead and real-time energy markets result from differences in the models used to operate each market that cannot be corrected through virtual bidding.[68]

A key assumption underlying the February 2018 order was that the limited set of nodes available for virtual trading is sufficiently protected from false arbitrage trades because price spreads resulting from modeling differences between the day-ahead and real-time markets are mitigated by the averaging of prices over a large number of buses at aggregate nodes.[69] This assumption is not correct, given the large share of INC, DEC, and UTC profits still attributable to modeling or operational differences between day-ahead and real-time models since the February 2018 order.

The assumption that modeling differences are averaged out over the multiple individual nodes included in aggregate nodes does not hold for multiple aggregate nodes in the current list of available up to congestion bidding nodes. The MMU recommends eliminating up to congestion (UTC) bidding at pricing nodes that aggregate only small sections of transmission zones with few physical assets. For example, the MMU recommends eliminating UTC bidding at the following pricing points: DPLEASTON_RESID_AGG, GORHAM_RESID_AGG, PENNPOWER_RESID_AGG, UGI_RESID_AGG, SMECO_RESID_AGG, AEPKY_RESID_AGG, and VINELAND_RESID_AGG. In November 2025, GORHAM_RESID_AGG added to the list of UTC locations.

Prices at larger aggregate nodes can also be affected by transmission constraints, especially when the line ratings on constraints are violated and transmission penalty factors are applied in the real-time energy market. This occurs both when line ratings are actually violated and when PJM operators reduce the line ratings in SCED. Even when the same constraints are modeled in day ahead and real time, constraint violations in real time may result from differences in the day-ahead and real-time operational environments such as intra hourly ramping limitations, changes to constraint limits, and unit commitments and decommitments. Price spreads due to modeling or operational differences can be significant, even when averaged over an aggregate node, and may persist for days or weeks. Virtual traders can often identify and profit from price spreads resulting from systematic modeling and operational differences between day-ahead and real-time affecting specific generators or aggregate nodes. The MMU recommends eliminating INC, DEC, and UTC bidding at pricing nodes that allow market participants to profit from modeling issues.

Market Performance

PJM locational marginal prices (LMPs) are a direct measure of market performance. The market performs optimally when the market structure provides incentives for market participants to behave competitively. In a competitive market, prices equal the short run marginal cost of the marginal unit of output and reflect the most efficient and least cost allocation of resources to meet demand.

LMP

The behavior of individual market entities within a market structure is reflected in market prices. PJM locational marginal prices (LMPs) are a direct measure of market performance. Price level is a good, general indicator of market performance, although overall price results must be interpreted carefully because of the multiple factors that affect them. Among other things, overall average prices reflect changes in supply and demand, generation fuel mix, the cost of fuel, emission related expenses, markup and local price differences caused by congestion. PJM also may administratively set prices with shortage pricing, the creation of closed loop interfaces related to demand side resources, surrogate constraints for reactive power and generator stability, or influence prices through manual interventions such as load biasing, changing constraint limits and transmission constraint penalty factors, and committing reserves beyond the requirement, or change price formation through fast start pricing.

The real-time average LMP in the first three months of 2026 increased $28.61 per MWh, or 58.2 percent, from the first three months of 2025, from

68 PJM Interconnection, LLC, "Proposed Revisions To Reduce Bidding Points for Virtual Transactions," Docket No. ER18-88, October 17, 2017 at 9–10: "Discrepancies between the models can occur for various reasons despite PJM's best attempts to minimize them…Because individual nodes are more highly impacted by modeling discrepancies than aggregated locations due to averaging, they are often locations where Virtual Transactions can profit. Profits collected by Virtual Transactions in these cases lead to additional costs for PJM members without any benefits."

69 See 162 FERC ¶ 61,139 at PP 35–36 ("We accept PJM's proposal to limit eligible bidding points for UTCs to hubs, residual metered load, and interfaces. First, we agree with the IMM's statement that PJM's proposal to limit the UTC bid locations to interfaces, zones, and hubs will minimize false arbitrage opportunities for UTCs currently being pursued through penny bids, as the effect of modeling differences between the day-ahead and real-time markets are minimized at these aggregates.").

$49.17 per MWh to $77.78 per MWh. The real-time load-weighted average LMP in the first three months of 2026 increased $35.37 per MWh, or 67.8 percent, from the first three months of 2025, from $52.20 per MWh to $87.57 per MWh.

The costs of fuel, emissions, and consumables, fundamental components of the real-time load-weighted average LMP, increased $14.92 per MWh from $37.78 per MWh in the first three months of 2025 to $52.70 per MWh in the first three months of 2026, or 42.2 percent of the increase in real-time load-weighted average LMP.

The day-ahead average LMP in the first three months of 2026 increased $34.13 per MWh, or 67.9 percent, from the first three months of 2025, from $50.27 per MWh to $84.40 per MWh. The day-ahead load-weighted average LMP in the first three months of 2026 increased $41.70 per MWh, or 77.8 percent, from the first three months of 2025, from $53.60 per MWh to $95.30 per MWh.

Occasionally, in a constrained market, the LMPs at some pricing nodes can exceed the offer price of the highest cleared generator in the supply curve.[70] In the nodal pricing system, the LMP at a pricing node is the total cost of meeting incremental demand at that node. When there are binding transmission constraints, satisfying the marginal increase in demand at a node may require increasing the output of some generators while simultaneously decreasing the output of other generators, to ensure that the transmission constraints are not violated. The total cost of redispatching multiple generators can at times exceed the cost of marginally increasing the output of the most expensive generator offered. Thus, the LMPs at some pricing nodes exceed $1,000 per MWh, the cap on the generators' offer price in the PJM market.[71]

LMP may, at times, be set by administratively defined transmission constraint penalty factors, which equal a default level of $30,000 per MWh in the day-ahead market dispatch run and $2,000 per MWh in the real-time market and in the day-ahead market pricing run. When a transmission constraint is binding and there are no generation alternatives to resolve the constraint, the transmission limits may be violated in the market dispatch solution. When this occurs, the shadow price of the constraint is set by transmission constraint penalty factors. The shadow price directly affects the LMP. Transmission constraint penalty factors are administratively determined and can be thought of as a form of locational scarcity pricing. However, PJM operator interventions to reduce the control limits on transmission constraint line ratings used in the market clearing unnecessarily trigger transmission constraint penalty factors and significantly increase prices. A competitive market does not require that prices increase when PJM artificially triggers transmission constraint penalty factors.

70 See O'Neill R. P, Mead D. and Malvadkar P. "On Market Clearing Prices Higher than the Highest Bid and Other Almost Paranormal Phenomena." *The Electricity Journal* 2005; 18(2) at 19–27.

71 The offer cap in PJM was temporarily increased to $1,800 per MWh prior to the winter of 2014/2015. A new cap of $2,000 per MWh, only for offers with costs exceeding $1,000 per MWh, went into effect on December 14, 2015. See 153 FERC ¶ 61,289 (2015).

Fast Start Pricing: DLMP and PLMP

PJM implemented fast start pricing in both the day-ahead and real-time markets on September 1, 2021. Fast start pricing is based on an incorrect LMP calculation called the pricing run. The pricing run LMP (PLMP) is the official settlement LMP in PJM, replacing the dispatch run LMP (DLMP). Unless otherwise specified, the LMP tables and figures show the PLMP for September 1, 2021, and after.

The pricing run calculates LMP using the same optimal power flow algorithm as the dispatch run while simultaneously ignoring (relaxing) the economic minimum and maximum output MW constraints for all eligible fast start units. Fast start units must have notification time plus start time less than or equal to one hour; minimum run time less than or equal to one hour; and can set price only when online and running for PJM, not self scheduled.

The goal of fast start pricing is to allow inflexible resources to set prices based on the sum of their commitment costs per MWh and their marginal costs. 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 new forms of uplift in an attempt to counter the distorted incentives inherent in fast start pricing.

PJM has also introduced other differences between the dispatch run and pricing run that are not related to fast start pricing. For example, in the day-ahead market, PJM uses a default $30,000 per MWh transmission constraint penalty factor in the dispatch run and a $2,000 per MWh transmission constraint penalty factor in the pricing run. Starting on October 1, 2022, PJM uses capping of the system marginal price only in the pricing run, which affected real-time market prices during Winter Storm Elliott in December 2022. On June 24 and October 3, PJM capped the energy LMP in the pricing run at $3,700 per MWh for two five minute intervals in the hour beginning at 1800 and one five minute interval in the hour beginning at 1900. This system marginal price (SMP) capping process has not been reviewed by FERC or included in the PJM Operating Agreement.

DLMP and PLMP

Table 3-32 shows the day-ahead and real-time monthly load-weighted average PLMP and DLMP in 2025 and the first three months of 2026.

The real-time load-weighted average PLMP was $87.57 per MWh for the first three months of 2026, which is 8.0 percent, $6.48 per MWh, higher than the real-time load-weighted average DLMP of $81.08 per MWh. The real-time load-weighted average PLMP was $50.73 per MWh in 2025, which is 8.4 percent, $3.93 per MWh, higher than the real-time load-weighted average DLMP of $46.79 per MWh. In the first three months of 2026, the estimated impact of fast start pricing, based on the difference between the real-time PLMP and DLMP times real-time load, was $1.4 billion.[72]

The day-ahead load-weighted average PLMP was $95.30 per MWh for the first three months of 2026, which is -5.3 percent, -$5.31 per MWh, lower than the day-ahead load-weighted average DLMP of $100.61 per MWh.

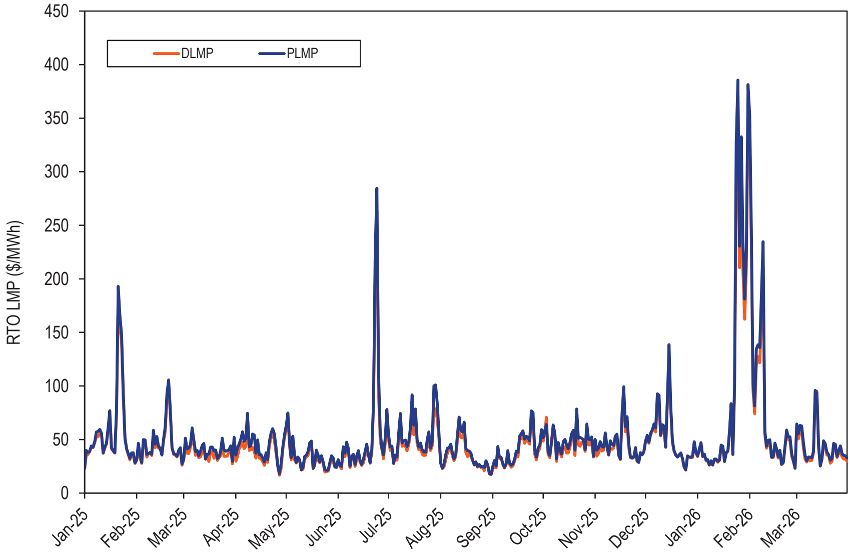
Table 3-32 Day-ahead and real-time load-weighted average DLMP and PLMP: 2025 through March 2026

		Day-Ahead Load-Weighted Average				Real-Time Load-Weighted Average			
Year	Month	DLMP	PLMP	Difference	Percent Difference	DLMP	PLMP	Difference	Percent Difference
2025	Jan	$67.53	$67.74	$0.21	0.3%	$59.93	$62.87	$2.94	4.9%
2025	Feb	$48.85	$49.02	$0.16	0.3%	$46.27	$48.90	$2.62	5.7%
2025	Mar	$40.76	$40.74	($0.03)	(0.1%)	$37.82	$42.11	$4.30	11.4%
2025	Apr	$44.36	$44.35	($0.01)	(0.0%)	$40.07	$45.42	$5.35	13.4%
2025	May	$37.56	$37.40	($0.16)	(0.4%)	$33.98	$36.34	$2.36	6.9%
2025	Jun	$53.01	$53.14	$0.13	0.2%	$62.53	$68.13	$5.60	9.0%
2025	Jul	$66.56	$66.76	$0.20	0.3%	$52.41	$59.38	$6.97	13.3%
2025	Aug	$39.24	$39.27	$0.03	0.1%	$35.97	$39.52	$3.55	9.9%
2025	Sep	$41.26	$41.24	($0.02)	(0.0%)	$40.49	$43.71	$3.22	7.9%
2025	Oct	$50.56	$50.73	$0.17	0.3%	$47.32	$51.01	$3.69	7.8%
2025	Nov	$49.70	$49.85	$0.15	0.3%	$43.82	$47.08	$3.26	7.4%
2025	Dec	$57.97	$58.08	$0.11	0.2%	$52.55	$55.29	$2.74	5.2%
2025	Jan - Mar	$53.47	$53.60	$0.12	0.2%	$48.95	$52.20	$3.25	6.6%
2025	Jan - Dec	$50.61	$50.70	$0.09	0.2%	$46.79	$50.73	$3.93	8.4%
2026	Jan	$163.50	$148.80	($14.70)	(9.0%)	$106.94	$115.98	$9.04	8.5%
2026	Feb	$83.61	$83.95	$0.34	0.4%	$86.43	$93.41	$6.98	8.1%
2026	Mar	$42.07	$42.21	$0.14	0.3%	$43.35	$46.14	$2.79	6.4%
2026	Jan - Mar	$100.61	$95.30	($5.31)	(5.3%)	$81.08	$87.57	$6.48	8.0%

72 See Market Monitor Report, MMU report to the PJM Members Committee (April 22, 2026) at 39.

Figure 3-25 shows the real-time daily average DLMP and PLMP in 2025 through March 2026.

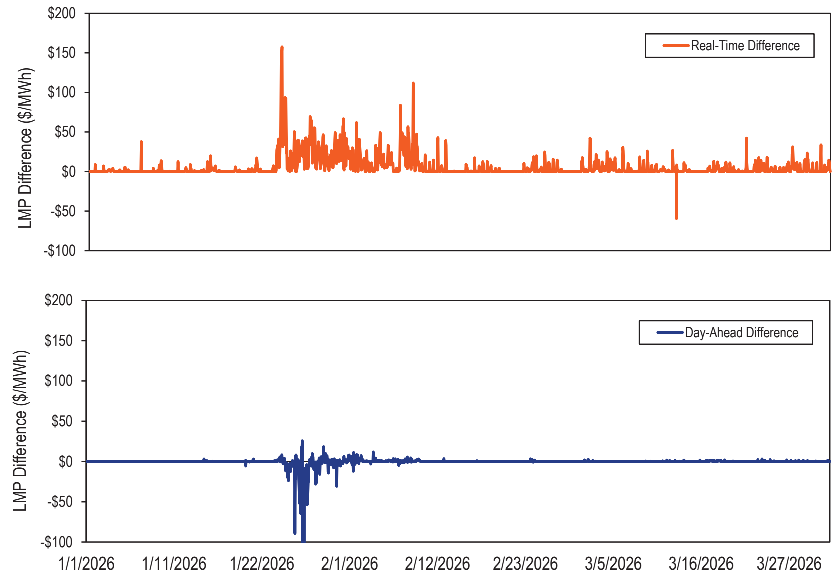
Figure 3-25 Real-time daily average DLMP and PLMP: 2025 through March 2026



Fast start pricing created a larger difference between DLMP and PLMP in real time than in day ahead. Figure 3-26 shows the hourly difference between DLMP and PLMP in day-ahead and real-time for 2025.

The negative difference between DA DLMP and PLMP was a result of PJM's continued use of an extremely high transmission constraint penalty factor only in the DA DLMP run that resulted in high DA DLMP values when triggered and therefore DA DLMP values greater than DA PLMP values. The large differences between DA DLMP and PLMP on January 27, 2026, was negative $5,060 per MWh. In the dispatch run, the penalty factor was set at $30,000, while in the pricing run the penalty factor was set at $2,000.

Figure 3-26 Hourly difference between DLMP and PLMP for day-ahead and real-time: January through March, 2026 [73]



73 This figure truncates a negative DA LMP difference of -$5,060 per MWh on January 27, 2026.

Figure 3-27 shows the hourly average load and LMP difference by hour of the day for the first three months of 2026. The real-time PLMP minus DLMP difference is largest at the times of the morning and evening peak loads.

Figure 3-27 Hourly average load and LMP difference: January through March, 2026

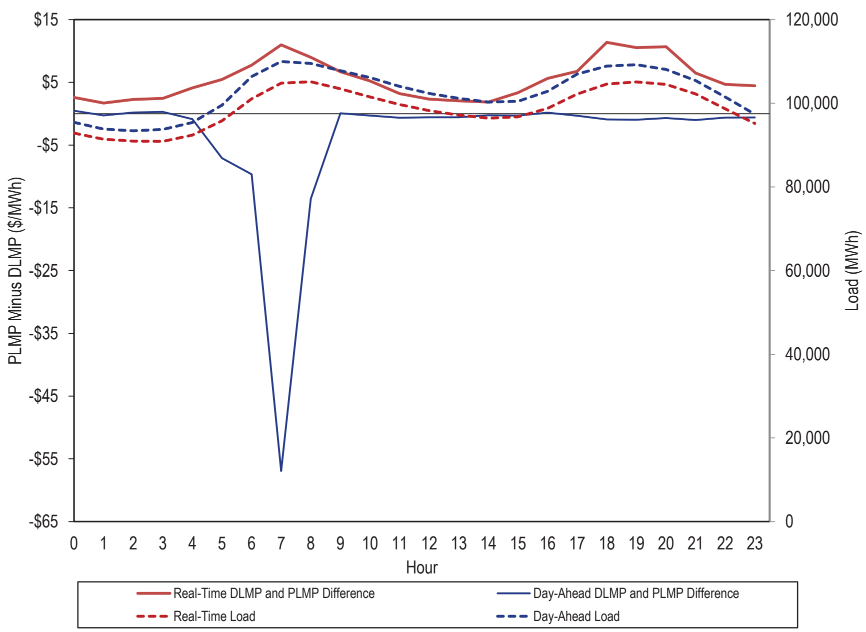


Table 3-33 shows the percent of total marginal units that are fast start units by unit type in 2025 and the first three months of 2026. While wind units are defined as fast start units, a wind unit on the margin does not result in a higher PLMP than DLMP when the unit has no commitment costs.

Table 3-33 Fast start units as a percent of real-time marginal units: 2025 through March 2026

		Dispatch Run				Pricing Run			
Year	Month	CT	Diesel	Wind	All Fast Start Units	CT	Diesel	Wind	All Fast Start Units
2025	Jan	0.8%	0.6%	0.1%	1.5%	4.5%	2.1%	0.1%	6.8%
2025	Feb	1.5%	0.1%	0.4%	2.0%	3.7%	0.6%	0.3%	4.6%
2025	Mar	0.5%	4.5%	0.1%	5.2%	3.4%	5.0%	0.1%	8.6%
2025	Apr	1.9%	1.8%	0.3%	4.1%	7.1%	2.2%	0.3%	9.7%
2025	May	0.6%	0.3%	0.0%	1.0%	3.9%	1.5%	0.0%	5.4%
2025	Jun	1.4%	0.2%	0.0%	1.6%	6.2%	0.8%	0.0%	7.0%
2025	Jul	2.6%	0.6%	0.0%	3.2%	11.2%	1.5%	0.0%	12.8%
2025	Aug	2.2%	0.5%	0.0%	2.7%	7.8%	1.1%	0.0%	8.9%
2025	Sep	1.2%	0.4%	0.0%	1.6%	5.7%	1.2%	0.0%	6.9%
2025	Oct	1.4%	0.3%	0.2%	1.8%	4.8%	0.6%	0.2%	5.6%
2025	Nov	0.7%	0.5%	0.6%	1.8%	3.8%	1.3%	0.5%	5.7%
2025	Dec	1.8%	0.1%	0.1%	1.9%	6.1%	0.6%	0.1%	6.7%
2025	Jan - Mar	0.9%	1.8%	0.2%	2.9%	3.9%	2.6%	0.2%	6.7%
2025	Total	1.4%	0.8%	0.2%	2.4%	5.7%	1.5%	0.1%	7.4%
2026	Jan	1.0%	0.2%	0.3%	1.6%	5.9%	0.7%	0.2%	6.8%
2026	Feb	1.5%	0.6%	0.9%	3.0%	6.3%	1.3%	0.8%	8.5%
2026	Mar	0.7%	0.4%	0.2%	1.4%	3.0%	0.6%	0.1%	3.8%
2026	Jan - Mar	1.1%	0.4%	0.5%	2.0%	5.1%	0.9%	0.4%	6.4%

Table 3-34 shows the difference between day-ahead and real-time zonal average DLMP and PLMP for the first three months of 2026.

Fast start pricing affects some zones more than others. The average difference in real-time DLMP and PLMP in DPL was $7.12 per MWh, while the average difference in real-time DLMP and PLMP in COMED was $3.13 per MWh.

Table 3-34 Day-ahead and real-time zonal average DLMP and PLMP (Dollars per MWh): January through March, 2026

	2026 (Jan-Mar)							
	Day-Ahead				Real-Time			
Zone	Average DLMP	Average PLMP	Difference	Percent Difference	Average DLMP	Average PLMP	Difference	Percent Difference
ACEC	$80.09	$80.01	($0.07)	(0.1%)	$65.52	$71.45	$5.93	9.0%
AEP	$73.75	$73.09	($0.67)	(0.9%)	$62.24	$67.22	$4.98	8.0%
APS	$109.00	$101.31	($7.69)	(7.1%)	$89.86	$96.07	$6.21	6.9%
ATSI	$69.64	$69.89	$0.25	0.4%	$56.08	$61.03	$4.95	8.8%
BGE	$143.12	$119.74	($23.38)	(16.3%)	$107.19	$113.43	$6.24	5.8%
COMED	$50.54	$51.13	$0.59	1.2%	$31.17	$34.31	$3.13	10.1%
DAY	$74.05	$73.64	($0.41)	(0.6%)	$59.85	$64.90	$5.05	8.4%
DUKE	$72.06	$71.71	($0.35)	(0.5%)	$58.79	$63.72	$4.93	8.4%
DOM	$118.22	$110.47	($7.75)	(6.6%)	$103.98	$110.28	$6.30	6.1%
DPL	$86.62	$86.70	$0.08	0.1%	$71.57	$78.69	$7.12	9.9%
DUQ	$65.76	$66.50	$0.73	1.1%	$54.78	$59.98	$5.20	9.5%
EKPC	$72.74	$72.09	($0.65)	(0.9%)	$60.05	$64.90	$4.85	8.1%
JCPLC	$81.88	$81.48	($0.40)	(0.5%)	$66.47	$72.47	$6.00	9.0%
MEC	$84.77	$83.57	($1.20)	(1.4%)	$67.52	$73.71	$6.19	9.2%
OVEC	$69.69	$69.41	($0.27)	(0.4%)	$55.75	$60.45	$4.70	8.4%
PECO	$78.52	$78.48	($0.03)	(0.0%)	$64.49	$70.33	$5.84	9.1%
PE	$79.96	$79.04	($0.92)	(1.2%)	$63.47	$69.49	$6.02	9.5%
PEPCO	$144.13	$120.72	($23.41)	(16.2%)	$109.50	$115.82	$6.32	5.8%
PPL	$82.07	$81.05	($1.02)	(1.2%)	$65.38	$71.36	$5.98	9.1%
PSEG	$83.25	$82.98	($0.27)	(0.3%)	$68.31	$74.34	$6.03	8.8%
REC	$85.23	$85.12	($0.11)	(0.1%)	$71.42	$77.46	$6.05	8.5%

Table 3-35 shows the difference between day-ahead and real-time average DLMP and PLMP for PJM hubs for the first three months of 2026.

The average difference in real-time DLMP and PLMP for the EASTERN HUB was $6.86 per MWh, while the average difference in real-time DLMP and PLMP for the N ILLINOIS HUB was $3.12 per MWh.

Table 3-35 Day-ahead and real-time average DLMP and PLMP for PJM hubs (Dollars per MWh): January through March, 2026

	2026 (Jan-Mar)							
	Day-Ahead				Real-Time			
Hub	Average DLMP	Average PLMP	Difference	Percent Difference	Average DLMP	Average PLMP	Difference	Percent Difference
AEP GEN HUB	$67.14	$67.14	($0.00)	(0.0%)	$53.64	$58.14	$4.50	8.4%
AEP-DAYTON HUB	$71.08	$70.66	($0.42)	(0.6%)	$57.48	$62.31	$4.82	8.4%
ATSI GEN HUB	$68.24	$68.60	$0.35	0.5%	$54.91	$59.94	$5.03	9.2%
CHICAGO GEN HUB	$50.51	$51.10	$0.59	1.2%	$32.73	$36.01	$3.28	10.0%
CHICAGO HUB	$50.89	$51.46	$0.58	1.1%	$31.23	$34.37	$3.14	10.1%
DOMINION HUB	$108.64	$102.14	($6.50)	(6.0%)	$97.66	$103.75	$6.09	6.2%
EASTERN HUB	$84.81	$84.89	$0.08	0.1%	$70.29	$77.15	$6.86	9.8%
N ILLINOIS HUB	$50.48	$51.08	$0.60	1.2%	$31.08	$34.20	$3.12	10.1%
NEW JERSEY HUB	$82.12	$81.85	($0.27)	(0.3%)	$67.11	$73.10	$6.00	8.9%
OHIO HUB	$70.46	$70.20	($0.26)	(0.4%)	$56.88	$61.72	$4.83	8.5%
WEST INT HUB	$82.61	$80.55	($2.06)	(2.5%)	$69.49	$74.61	$5.11	7.4%
WESTERN HUB	$108.01	$97.41	($10.59)	(9.8%)	$84.18	$90.24	$6.05	7.2%

Table 3-36 shows the frequency of the real-time pricing interval differences in DLMP and PLMP by price range for PJM zones for the first three months of 2026.

Table 3-36 Frequency of real-time interval difference (dollars per MWh) between zonal DLMP and PLMP: January through March, 2026

	2026 (Jan-Mar)									
Zone	< ($50)	($50) to ($10)	($10) to $0	$0	$0 to $10	$10 to $20	$20 to $50	$50 to $100	$100 to $200	>= $200
PJM-RTO	0.0%	0.0%	0.6%	55.4%	29.1%	6.3%	6.3%	1.9%	0.4%	0.0%
ACEC	0.0%	0.1%	4.9%	55.7%	25.5%	4.6%	6.0%	2.3%	0.9%	0.0%
AEP	0.0%	0.0%	2.0%	55.5%	28.5%	6.5%	5.5%	1.6%	0.4%	0.0%
APS	0.0%	0.1%	1.2%	55.5%	27.1%	6.4%	6.6%	2.5%	0.6%	0.0%
ATSI	0.0%	0.1%	2.2%	55.5%	28.3%	6.5%	5.5%	1.6%	0.4%	0.0%
BGE	0.2%	0.5%	1.8%	55.4%	25.8%	6.5%	6.6%	2.4%	0.7%	0.1%
COMED	0.0%	0.3%	6.2%	56.0%	28.5%	4.6%	3.3%	0.8%	0.3%	0.0%
DAY	0.0%	0.0%	1.8%	55.5%	28.6%	6.6%	5.3%	1.7%	0.4%	0.0%
DUKE	0.0%	0.1%	1.8%	55.6%	28.6%	6.7%	5.3%	1.7%	0.4%	0.0%
DOM	0.0%	0.2%	1.7%	55.5%	27.0%	6.4%	6.0%	2.4%	0.7%	0.1%
DPL	0.0%	0.2%	6.1%	55.6%	23.4%	4.3%	5.5%	3.4%	1.3%	0.1%
DUQ	0.0%	0.1%	2.1%	55.4%	27.8%	6.5%	5.8%	1.8%	0.4%	0.0%
EKPC	0.0%	0.0%	1.7%	55.6%	28.8%	6.5%	5.6%	1.5%	0.3%	0.0%
JCPLC	0.0%	0.0%	3.2%	55.7%	27.1%	4.7%	6.1%	2.3%	0.9%	0.0%
MEC	0.0%	0.1%	2.7%	55.5%	27.5%	4.7%	6.0%	2.5%	0.9%	0.1%
OVEC	0.0%	0.1%	1.9%	55.6%	28.9%	6.4%	5.2%	1.5%	0.3%	0.0%
PECO	0.0%	0.1%	5.9%	55.6%	24.6%	4.7%	6.0%	2.3%	0.9%	0.0%
PE	0.0%	0.1%	1.1%	55.4%	28.6%	5.3%	6.4%	2.2%	0.7%	0.0%
PEPCO	0.1%	0.4%	1.9%	55.5%	26.1%	6.5%	6.2%	2.5%	0.7%	0.1%
PPL	0.0%	0.1%	3.1%	55.6%	27.5%	4.6%	5.9%	2.3%	0.9%	0.0%
PSEG	0.0%	0.1%	2.9%	55.7%	27.1%	4.8%	6.2%	2.3%	0.9%	0.0%
REC	0.0%	0.1%	2.3%	55.5%	27.4%	5.1%	6.4%	2.3%	0.8%	0.0%

Real-Time Average LMP

Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[74]

PJM Real-Time Average LMP

Table 3-37 shows the real-time average LMP for the first three months of 1998 through 2026.[75] The real-time average LMP in the first three months of 2026 increased $28.61 per MWh, or 58.2 percent, from the first three months of 2025, from $49.17 per MWh to $77.78 per MWh.

Table 3-37 Real-time average LMP (Dollars per MWh): January through March, 1998 through 2026

	Real-Time LMP			Year to Year Change			
Jan-Mar	Average	Median	Standard Deviation	Average	Average Percent	Median	Standard Deviation
1998	$17.51	$15.30	$7.84	NA	NA	NA	NA
1999	$18.79	$16.56	$7.29	$1.28	7.3%	8.3%	(7.0%)
2000	$23.66	$17.73	$16.22	$4.87	25.9%	7.0%	122.4%
2001	$33.77	$26.01	$20.79	$10.12	42.8%	46.8%	28.2%
2002	$22.23	$19.22	$9.61	($11.54)	(34.2%)	(26.1%)	(53.8%)
2003	$49.57	$43.08	$30.54	$27.34	123.0%	124.2%	217.9%
2004	$46.37	$41.04	$24.07	($3.20)	(6.5%)	(4.8%)	(21.2%)
2005	$46.51	$40.62	$22.07	$0.14	0.3%	(1.0%)	(8.3%)
2006	$52.98	$46.15	$23.29	$6.47	13.9%	13.6%	5.5%
2007	$55.34	$47.15	$33.29	$2.36	4.5%	2.2%	43.0%
2008	$66.75	$57.05	$35.54	$11.41	20.6%	21.0%	6.8%
2009	$47.29	$40.56	$21.99	($19.46)	(29.2%)	(28.9%)	(38.1%)
2010	$44.13	$37.82	$21.87	($3.16)	(6.7%)	(6.8%)	(0.6%)
2011	$44.76	$38.14	$23.10	$0.63	1.4%	0.8%	5.6%
2012	$30.38	$28.82	$11.63	($14.37)	(32.1%)	(24.4%)	(49.7%)
2013	$36.33	$32.29	$18.47	$5.95	19.6%	12.1%	58.9%
2014	$84.04	$48.77	$119.84	$47.71	131.3%	51.0%	548.8%
2015	$47.39	$31.95	$42.42	($36.65)	(43.6%)	(34.5%)	(64.6%)
2016	$25.60	$22.91	$12.99	($21.79)	(46.0%)	(28.3%)	(69.4%)
2017	$29.39	$25.71	$12.28	$3.79	14.8%	12.2%	(5.4%)
2018	$44.65	$26.83	$49.68	$15.27	51.9%	4.4%	304.5%
2019	$29.13	$25.36	$15.09	($15.53)	(34.8%)	(5.5%)	(69.6%)
2020	$19.42	$18.56	$6.98	($9.71)	(33.3%)	(26.8%)	(53.8%)
2021	$29.78	$23.66	$23.91	$10.36	53.4%	27.5%	242.6%
2022	$51.95	$43.28	$36.57	$22.17	74.5%	82.9%	53.0%
2023	$29.57	$26.50	$18.55	($22.38)	(43.1%)	(38.8%)	(49.3%)
2024	$29.19	$23.36	$24.64	($0.38)	(1.3%)	(11.8%)	32.8%
2025	$49.17	$37.99	$36.17	$19.98	68.5%	62.6%	46.8%
2026	$77.78	$37.24	$110.80	$28.61	58.2%	(2.0%)	206.4%

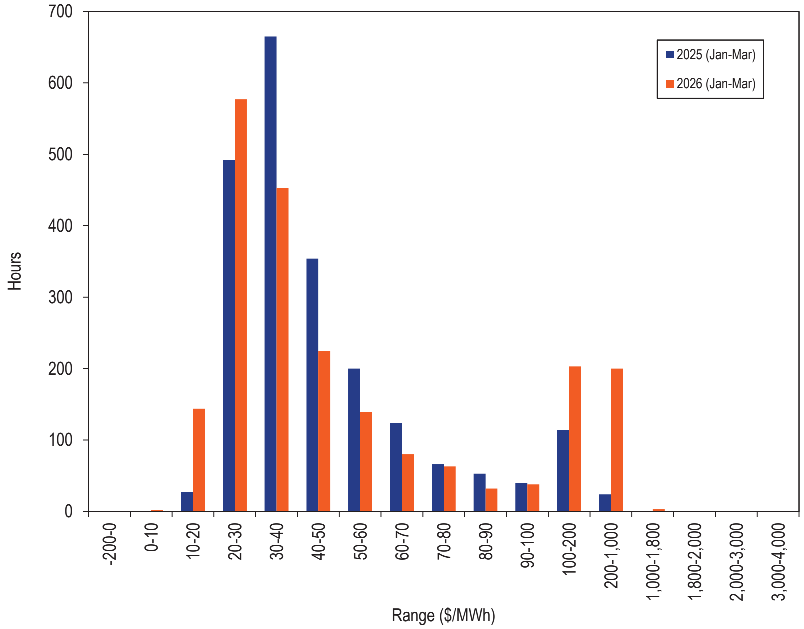
74 See the *Technical Reference for PJM Markets*, at "Calculating Locational Marginal Price," p 16-18 for detailed definition of Real-Time LMP. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

75 The system average LMP is the average of the hourly LMP without any weighting. The only exception is that market-clearing prices (MCPs) are included for January to April 1998. MCP was the single market-clearing price calculated by PJM prior to implementation of LMP.

PJM Real-Time Average LMP Duration

Figure 3-28 shows the hourly distribution of the real-time average LMP in the first three months of 2025 and 2026. In the first three months of 2025, the most common price range was $20 to $30 per MWh. In the first three months of 2026, the most common price range was $30 to $40 per MWh.

Figure 3-28 Distribution of real-time LMP: January through March, 2025 and 2026



Real-Time Load-Weighted Average LMP

Higher demand generally results in higher prices, all else constant. As a result, load-weighted, average prices are generally higher than average prices. Load-weighted average LMP reflects the average real-time LMP paid for actual MWh consumed during a year. Load-weighted average LMP is the average of PJM hourly LMP, with each hourly LMP weighted by the PJM total hourly load.

PJM Real-Time Load-Weighted Average LMP

Table 3-38 shows the real-time load-weighted average LMP for the first three months of 1998 through 2026. The real-time load-weighted average LMP in the first three months of 2026 increased $35.37 per MWh, or 67.8 percent, from the first three months of 2025, from $52.20 per MWh to $87.57 per MWh.

Table 3-38 Real-time load-weighted average LMP (Dollars per MWh): January through March, 1998 through 2026

	Real-Time Load-Weighted Average LMP			Year to Year Change			
Jan-Mar	Average	Median	Standard Deviation	Average	Average Percent	Median	Standard Deviation
1998	$18.13	$15.80	$8.14	NA	NA	NA	NA
1999	$19.38	$16.90	$7.66	$1.25	6.9%	7.0%	(5.9%)
2000	$25.10	$18.25	$17.22	$5.72	29.5%	8.0%	124.9%
2001	$35.16	$27.38	$21.52	$10.06	40.1%	50.0%	25.0%
2002	$23.01	$19.89	$9.93	($12.15)	(34.6%)	(27.4%)	(53.8%)
2003	$51.93	$46.12	$30.99	$28.91	125.6%	131.9%	211.9%
2004	$48.77	$43.22	$24.62	($3.16)	(6.1%)	(6.3%)	(20.6%)
2005	$48.37	$42.20	$22.62	($0.40)	(0.8%)	(2.4%)	(8.1%)
2006	$54.43	$47.62	$23.69	$6.05	12.5%	12.9%	4.7%
2007	$58.07	$50.60	$34.44	$3.65	6.7%	6.3%	45.4%
2008	$69.35	$60.11	$36.56	$11.28	19.4%	18.8%	6.2%
2009	$49.60	$42.23	$23.38	($19.76)	(28.5%)	(29.8%)	(36.1%)
2010	$45.92	$39.01	$22.99	($3.68)	(7.4%)	(7.6%)	(1.7%)
2011	$46.35	$39.11	$24.26	$0.43	0.9%	0.3%	5.5%
2012	$31.21	$29.25	$12.02	($15.15)	(32.7%)	(25.2%)	(50.5%)
2013	$37.41	$32.79	$19.90	$6.21	19.9%	12.1%	65.7%
2014	$92.98	$51.62	$134.40	$55.57	148.5%	57.4%	575.3%
2015	$50.91	$33.51	$46.43	($42.07)	(45.2%)	(35.1%)	(65.5%)
2016	$26.80	$23.45	$13.98	($24.11)	(47.4%)	(30.0%)	(69.9%)
2017	$30.28	$26.26	$13.08	$3.48	13.0%	12.0%	(6.4%)
2018	$49.45	$27.96	$55.22	$19.17	63.3%	6.5%	322.1%
2019	$30.16	$25.84	$16.18	($19.29)	(39.0%)	(7.6%)	(70.7%)
2020	$19.85	$18.87	$7.20	($10.31)	(34.2%)	(27.0%)	(55.5%)
2021	$30.84	$24.13	$24.58	$10.99	55.3%	27.9%	241.3%
2022	$54.13	$44.32	$38.74	$23.29	75.5%	83.7%	57.6%
2023	$30.28	$27.19	$19.80	($23.85)	(44.1%)	(38.7%)	(48.9%)
2024	$31.01	$24.46	$26.82	$0.73	2.4%	(10.0%)	35.4%
2025	$52.20	$39.62	$39.84	$21.19	68.3%	61.9%	48.5%
2026	$87.57	$39.95	$120.70	$35.37	67.8%	0.8%	203.0%

PJM Real-Time Monthly Load-Weighted Average LMP

Figure 3-29 shows the real-time monthly and yearly load-weighted average LMP for 1999 through the first three months of 2026.

Figure 3-29 Real-time monthly and yearly load-weighted average LMP: 1999 through March 2026

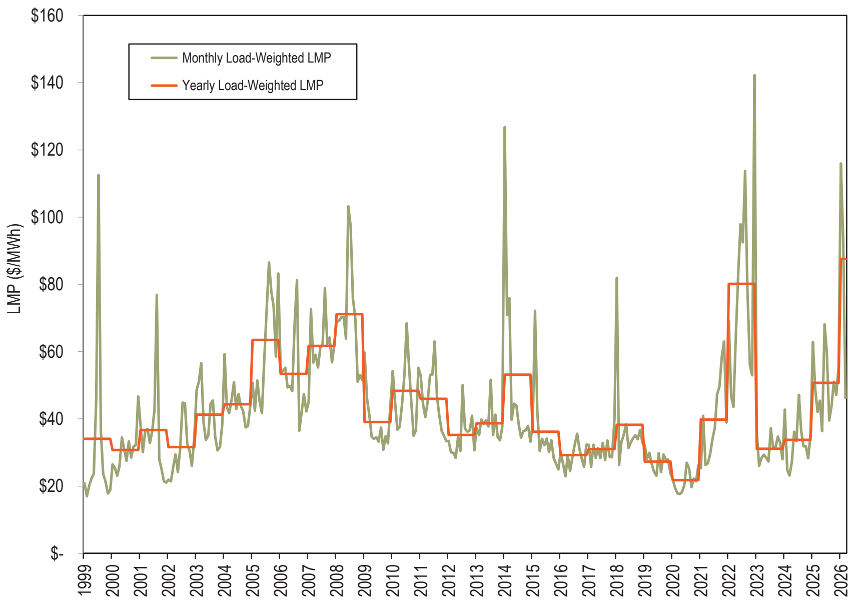


Table 3-39 shows the real-time monthly on peak and off peak load-weighted average LMP for 2025 through the first three months of 2026.

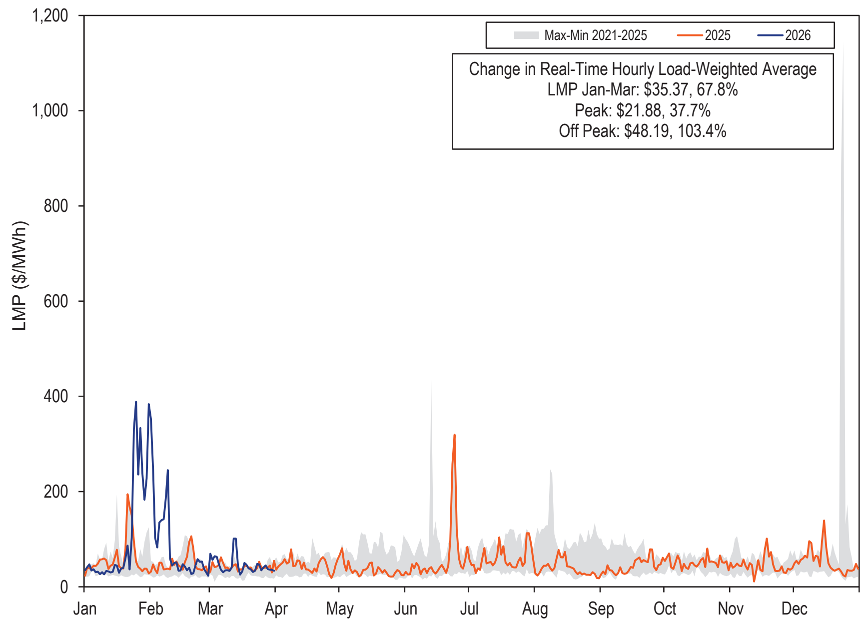
Table 3-39 Real-time monthly on peak and off peak load-weighted average LMP (Dollars per MWh): 2025 through March 2026

	2025				2026			
	Off Peak	On Peak	Difference	Percent Difference	Off Peak	On Peak	Difference	Percent Difference
Jan	$55.29	$70.54	$15.25	27.6%	$127.59	$102.73	($24.86)	(19.5%)
Feb	$43.75	$54.12	$10.37	23.7%	$106.39	$79.83	($26.56)	(25.0%)
Mar	$38.89	$45.68	$6.79	17.5%	$38.30	$53.85	$15.55	40.6%
Apr	$38.15	$52.08	$13.93	36.5%				
May	$27.32	$45.53	$18.21	66.7%				
Jun	$39.62	$94.51	$54.89	138.5%				
Jul	$39.08	$77.77	$38.68	99.0%				
Aug	$29.15	$49.92	$20.77	71.2%				
Sep	$34.41	$52.55	$18.14	52.7%				
Oct	$41.55	$59.43	$17.88	43.0%				
Nov	$40.52	$55.12	$14.59	36.0%				
Dec	$49.92	$60.68	$10.76	21.6%				

PJM Real-Time Daily Load-Weighted Average LMP

Figure **3-30** shows the real-time daily load-weighted average LMP for January 2025 through March 2026.

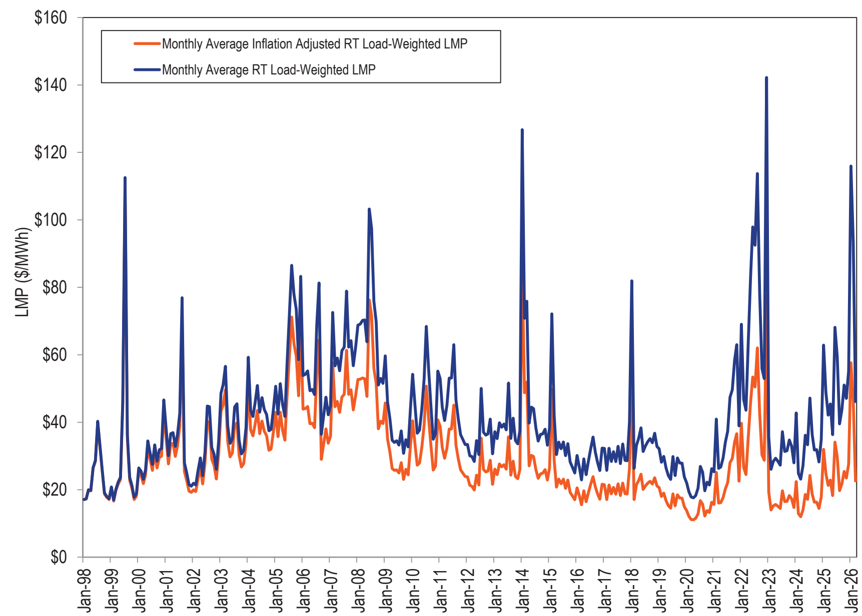
Figure 3-30 Real-time daily load-weighted average LMP: January 2025 through March 2026



PJM Real-Time Monthly Inflation Adjusted Load-Weighted Average LMP

Figure 3-31 shows the PJM real-time monthly load-weighted average LMP and inflation adjusted monthly load-weighted average LMP from January 1998 through March 2026.[76] [77] Table 3-40 shows the PJM real-time load-weighted average LMP and inflation adjusted load-weighted average LMP for the first three months of every year from 1998 through 2026.

Figure 3-31 Real-time monthly load-weighted average LMP unadjusted and adjusted for inflation: January 1998 through March 2026



76 To obtain the inflation adjusted, monthly, load-weighted, average LMP, the PJM system-wide load-weighted average LMP is deflated using the 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> (Accessed April 10, 2026)

77 The U.S. Bureau of Labor Statistics did not publish CPI data for October 2025. October 2025 CPI data was approximated using the geometric mean of September and November 2025 index values. Further information on approximating BLS data for missing data points can be found at: <https://www.bls.gov/cpi/factsheets/approximating-missing-data.htm> .

Table 3-40 Real-time load-weighted and inflation adjusted load-weighted average LMP: January through March, 1998 through 2026

	Load-Weighted Average LMP	Inflation Adjusted Load-Weighted Average LMP
	Jan-Mar	Jan-Mar
1998	$18.13	$18.10
1999	$19.38	$19.03
2000	$25.10	$23.89
2001	$35.16	$32.35
2002	$23.01	$20.90
2003	$51.93	$45.86
2004	$48.77	$42.36
2005	$48.37	$40.73
2006	$54.43	$44.21
2007	$58.07	$46.05
2008	$69.35	$52.85
2009	$49.60	$37.83
2010	$45.92	$34.21
2011	$46.35	$33.83
2012	$31.21	$22.14
2013	$37.41	$26.09
2014	$92.98	$64.01
2015	$50.91	$35.04
2016	$26.80	$18.25
2017	$30.28	$20.11
2018	$49.45	$32.17
2019	$30.16	$19.28
2020	$19.85	$12.42
2021	$30.84	$18.94
2022	$54.13	$30.86
2023	$30.28	$16.29
2024	$31.01	$16.17
2025	$52.20	$26.47
2026	$87.57	$43.33

Real-Time Dispatch and Pricing

On November 1, 2021, PJM implemented a new real-time dispatch process that aligned the timing of dispatch and pricing in the real-time energy market. The PJM Real-Time Energy Market is based on applications that produce the generator dispatch for energy and reserves, and five minute locational marginal prices (LMPs). These applications include the real-time security constrained economic dispatch (RT SCED), the locational pricing calculator (LPC), and the ancillary services optimizer (ASO).[78] The final real-time LMPs and ancillary service clearing prices are determined for every five minute interval by LPC.

Real-Time SCED and LPC

The LPC uses data from an approved RT SCED solution that was used to dispatch the resources in the system. RT SCED solves to meet load and reserve requirements forecast for a future point in time, called the target time. Prior to 2021, on average, PJM operators approved more than one RT SCED solution per five minute target time to send dispatch signals to resources. From 2021 through the first three months of 2026, on average, PJM operators approved one RT SCED solution per five minute target time to send dispatch signals to resources. PJM uses a subset of these approved RT SCED solutions in LPC to calculate real-time LMPs every five minutes. Prior to October 15, 2020, LPC used the latest available approved RT SCED solution to calculate prices, regardless of the target dispatch time of the RT SCED solution, but LPC assigned the prices to a five minute interval that did not contain the target time of the RT SCED case it used. On November 1, 2021, PJM implemented changes to RT SCED that solved the energy dispatch case using a five-minute dispatch period, and ramped resources for five minutes to meet the load and reserve requirements at the end of each five minute period. The approved RT SCED solution that dispatched units for each five minute period was also used to calculate prices for the same five minute interval, aligning the prices with the dispatch signals.

Table 3-41 shows the number of RT SCED case solutions, the number of solutions that were approved, and the number and percent of approved solutions used in LPC. The RT SCED execution frequency is once every five minutes. PJM operators have the ability to execute additional RT SCED cases. Each execution of RT SCED produces five solutions, using five different levels of load bias. Since prices are calculated every five minutes while five SCED solutions are produced every five minutes, there is, by definition, a larger number of SCED solutions than there are five minute intervals in any given period.

78 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Rev. 133 (Dec. 17, 2024).

Table 3-41 shows that in the first three months of 2026, 98.2 percent of approved RT SCED solutions that were used to send dispatch signals to generators were used in calculating real-time energy market prices, compared to 98.0 percent in all of 2025.

Table 3-41 RT SCED cases solved, approved and used in pricing: January 2025 through March 2026

	2025				2026			
Month	Number of RT SCED Solutions	Number of Approved RT SCED Solutions	Number of Approved RT SCED Solutions Used in LPC	RT SCED Solutions Used in LPC as Percent of Approved RT SCED Solutions	Number of RT SCED Solutions	Number of Approved RT SCED Solutions	Number of Approved RT SCED Solutions Used in LPC	RT SCED Solutions Used in LPC as Percent of Approved RT SCED Solutions
Jan	46,098	9,146	8,895	97.3%	45,724	9,048	8,878	98.1%
Feb	41,310	8,213	8,020	97.7%	41,058	8,151	7,982	97.9%
Mar	46,674	9,013	8,823	97.9%	45,526	8,981	8,838	98.4%
Apr	44,215	8,766	8,608	98.2%				
May	45,702	9,053	8,867	97.9%				
Jun	44,319	8,812	8,582	97.4%				
Jul	45,713	9,076	8,889	97.9%				
Aug	45,491	9,022	8,860	98.2%				
Sep	43,744	8,736	8,556	97.9%				
Oct	45,271	8,991	8,859	98.5%				
Nov	44,285	8,731	8,586	98.3%				
Dec	45,514	8,990	8,855	98.5%				
Total	538,336	106,549	104,400	98.0%	132,308	26,180	25,698	98.2%

Recalculation of Five Minute Real-Time Prices

PJM's five minute interval LMPs are obtained from solved LPC cases. PJM recalculates five minute interval real-time LMPs as it believes necessary to correct errors. To do so, PJM reruns LPC cases with modified inputs. The PJM OATT allows for posting of recalculated real-time prices no later than 1700 (EPT) of the tenth calendar day following the operating day. The OATT also requires PJM to notify market participants of the underlying error no later than 1700 (EPT) of the second business day following the operating day.[79]

Table 3-42 shows the number of five minute intervals in each month and number of five minute intervals in each month for which PJM recalculated real-time prices in 2025 and the first three months of 2026. In the first three months of 2026, PJM recalculated LMPs for 346 five minute intervals, or 1.3 percent of the total 25,908 five minute intervals.

Table 3-42 Number of five minute interval real-time prices recalculated: January 2025 through March 2026

	2025			2026		
Month	Number of Five Minute Intervals	Number of Five Minute Intervals for Which LMPs Were Recalculated	Percent	Number of Five Minute Intervals	Number of Five Minute Intervals for Which LMPs Were Recalculated	Percent
January	8,928	154	1.7%	8,928	123	1.4%
February	8,064	189	2.3%	8,064	136	1.7%
March	8,916	680	7.6%	8,916	87	1.0%
April	8,640	126	1.5%			
May	8,928	153	1.7%			
June	8,640	162	1.9%			
July	8,928	183	2.0%			
August	8,928	137	1.5%			
September	8,640	142	1.6%			
October	8,928	132	1.5%			
November	8,652	93	1.1%			
December	8,928	115	1.3%			
Total	105,120	2,266	2.2%	25,908	346	1.3%

79 OA Attachment K Section 1 § 1.10.8(e).

Day-Ahead Average LMP

Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[80]

PJM Day-Ahead Average LMP

Table 3-43 shows the day-ahead average LMP of the first three months of 2001 through 2026. The day-ahead average LMP in the first three months of 2026 increased $34.13 per MWh, or 67.9 percent, from the first three months of 2025, from $50.27 per MWh to $84.40 per MWh.

Table 3-43 Day-ahead average LMP (Dollars per MWh): January through March, 2001 to 2026

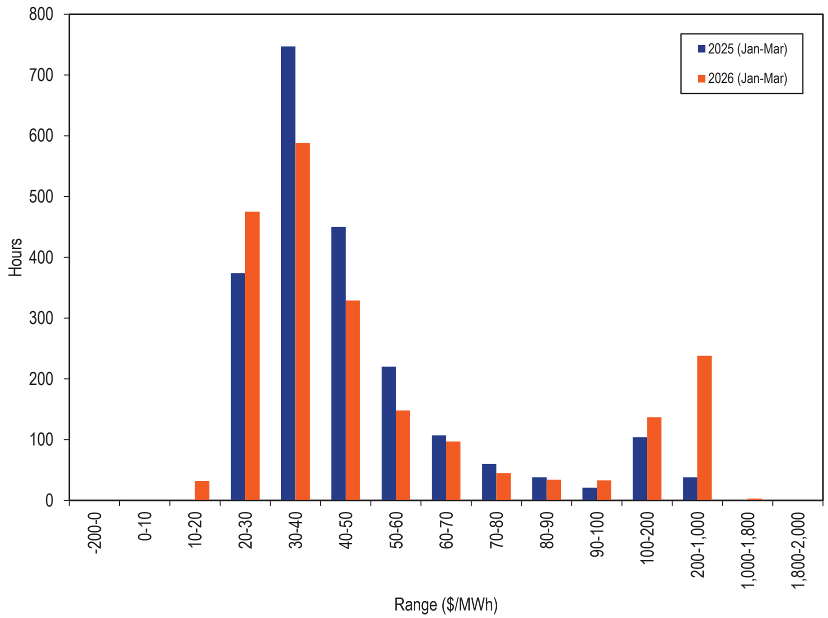
	Day-Ahead LMP			Year to Year Change			
Jan-Mar	Average	Median	Standard Deviation	Average	Average Percent	Median	Standard Deviation
2001	$36.45	$32.72	$16.39	NA	NA	NA	NA
2002	$22.43	$20.59	$7.56	($14.02)	(38.5%)	(37.1%)	(53.9%)
2003	$51.20	$46.06	$25.65	$28.77	128.2%	123.7%	239.3%
2004	$45.84	$43.01	$18.85	($5.36)	(10.5%)	(6.6%)	(26.5%)
2005	$45.14	$41.56	$16.19	($0.70)	(1.5%)	(3.4%)	(14.1%)
2006	$51.23	$48.53	$14.16	$6.08	13.5%	16.8%	(12.6%)
2007	$52.76	$49.43	$22.59	$1.54	3.0%	1.9%	59.5%
2008	$66.10	$62.57	$23.90	$13.34	25.3%	26.6%	5.8%
2009	$47.41	$43.43	$16.85	($18.69)	(28.3%)	(30.6%)	(29.5%)
2010	$46.13	$41.99	$15.93	($1.28)	(2.7%)	(3.3%)	(5.5%)
2011	$45.60	$41.10	$16.82	($0.54)	(1.2%)	(2.1%)	5.6%
2012	$30.82	$30.04	$6.63	($14.78)	(32.4%)	(26.9%)	(60.6%)
2013	$36.46	$34.45	$9.78	$5.65	18.3%	14.7%	47.5%
2014	$86.52	$52.80	$92.80	$50.06	137.3%	53.3%	848.8%
2015	$48.62	$35.48	$36.77	($37.90)	(43.8%)	(32.8%)	(60.4%)
2016	$26.90	$25.11	$8.83	($21.73)	(44.7%)	(29.2%)	(76.0%)
2017	$29.59	$27.33	$8.54	$2.70	10.0%	8.8%	(3.3%)
2018	$43.59	$29.01	$38.64	$14.00	47.3%	6.2%	352.5%
2019	$29.65	$26.82	$11.28	($13.94)	(32.0%)	(7.6%)	(70.8%)
2020	$19.66	$19.14	$4.43	($9.98)	(33.7%)	(28.6%)	(60.7%)
2021	$30.28	$25.44	$18.64	$10.62	54.0%	32.9%	320.9%
2022	$52.25	$46.67	$19.40	$21.97	72.5%	83.4%	4.1%
2023	$31.26	$29.08	$12.18	($20.99)	(40.2%)	(37.7%)	(37.2%)
2024	$30.26	$24.02	$23.81	($1.00)	(3.2%)	(17.4%)	95.4%
2025	$50.27	$39.11	$37.66	$20.01	66.1%	62.8%	58.2%
2026	$84.40	$39.57	$123.91	$34.13	67.9%	1.2%	229.0%

80 See the ***MMU Technical Reference for the PJM Markets***, at "Calculating Locational Marginal Price," for a detailed definition of day-ahead LMP. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

PJM Day-Ahead Average LMP Duration

Figure 3-32 shows the hourly distribution of the day-ahead average LMP for the first three months of 2025 and 2026.

Figure 3-32 Distribution of day-ahead LMP: January through March, 2025 and 2026



Day-Ahead Load-Weighted Average LMP

Day-ahead load-weighted LMP reflects the average LMP paid for day-ahead MWh. Day-ahead load-weighted LMP is the average of PJM day-ahead hourly LMP, each hourly LMP weighted by the PJM total cleared day-ahead, hourly load, including day-ahead fixed load, price-sensitive load, decrement bids and up to congestion.

PJM Day-Ahead Load-Weighted Average LMP

Table 3-44 shows the day-ahead load-weighted average LMP in the first three months of 2001 through 2026. The day-ahead load-weighted average LMP in the first three months of 2026 increased $41.70 per MWh, or 77.8 percent, from the first three months of 2025, from $53.60 per MWh to $95.30 per MWh.

Table 3-44 Day-ahead load-weighted average LMP (Dollars per MWh): January through March, 2001 to 2026

	Day-Ahead Load-Weighted Average LMP			Year to Year Change			
Jan-Mar	Average	Median	Standard Deviation	Average	Average Percent	Median	Standard Deviation
2001	$37.70	$34.55	$16.66	NA	NA	NA	NA
2002	$23.17	$21.18	$7.76	($14.53)	(38.5%)	(38.7%)	(53.4%)
2003	$53.16	$48.69	$25.75	$29.99	129.5%	129.9%	231.7%
2004	$47.75	$45.02	$19.19	($5.41)	(10.2%)	(7.5%)	(25.4%)
2005	$46.54	$42.88	$16.46	($1.21)	(2.5%)	(4.8%)	(14.2%)
2006	$52.40	$49.51	$14.29	$5.86	12.6%	15.5%	(13.2%)
2007	$54.87	$51.89	$23.16	$2.48	4.7%	4.8%	62.0%
2008	$68.00	$64.70	$24.35	$13.13	23.9%	24.7%	5.1%
2009	$49.44	$44.85	$17.54	($18.56)	(27.3%)	(30.7%)	(28.0%)
2010	$47.77	$43.62	$16.52	($1.67)	(3.4%)	(2.7%)	(5.8%)
2011	$47.14	$42.49	$17.73	($0.63)	(1.3%)	(2.6%)	7.3%
2012	$31.51	$30.44	$6.83	($15.64)	(33.2%)	(28.3%)	(61.5%)
2013	$37.26	$35.02	$10.26	$5.75	18.3%	15.0%	50.3%
2014	$94.97	$56.53	$102.23	$57.71	154.9%	61.4%	896.7%
2015	$52.02	$36.94	$40.10	($42.95)	(45.2%)	(34.7%)	(60.8%)
2016	$27.94	$25.99	$9.28	($24.08)	(46.3%)	(29.6%)	(76.8%)
2017	$30.40	$27.99	$8.98	$2.46	8.8%	7.7%	(3.3%)
2018	$47.55	$30.24	$42.58	$17.15	56.4%	8.0%	374.2%
2019	$30.76	$27.28	$12.56	($16.80)	(35.3%)	(9.8%)	(70.5%)
2020	$20.12	$19.54	$4.54	($10.64)	(34.6%)	(28.4%)	(63.9%)
2021	$31.58	$26.11	$20.01	$11.46	57.0%	33.6%	341.0%
2022	$54.23	$48.68	$20.18	$22.65	71.7%	86.4%	0.8%
2023	$32.16	$29.59	$13.25	($22.07)	(40.7%)	(39.2%)	(34.3%)
2024	$32.34	$24.80	$26.27	$0.18	0.6%	(16.2%)	98.2%
2025	$53.60	$40.89	$41.58	$21.26	65.7%	64.9%	58.3%
2026	$95.30	$42.00	$136.36	$41.70	77.8%	2.7%	228.0%

PJM Day-Ahead Monthly Load-Weighted Average LMP

Figure 3-33 shows the day-ahead monthly and yearly load-weighted average LMP in 2001 through the first three months of 2026.

Figure 3-33 Day-ahead monthly and yearly load-weighted average LMP: 2001 through March 2026

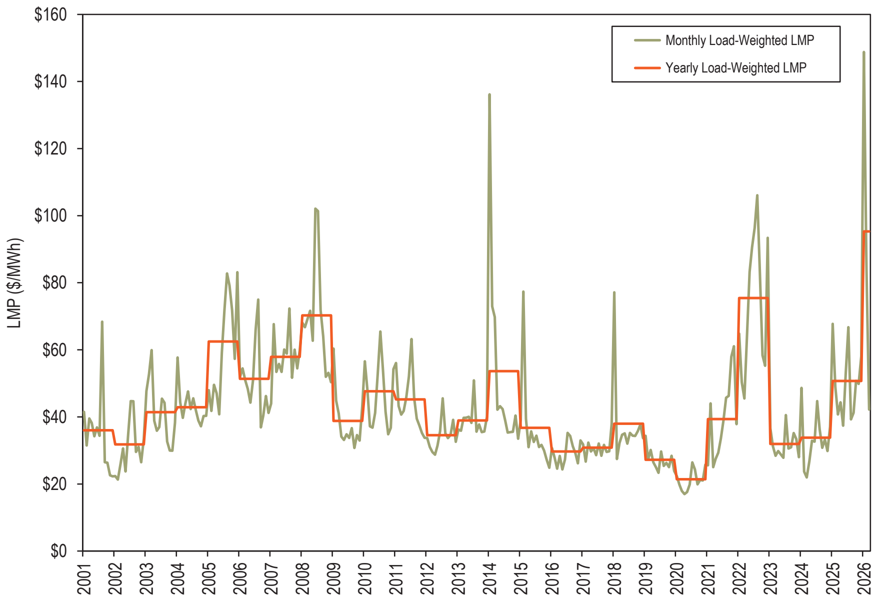
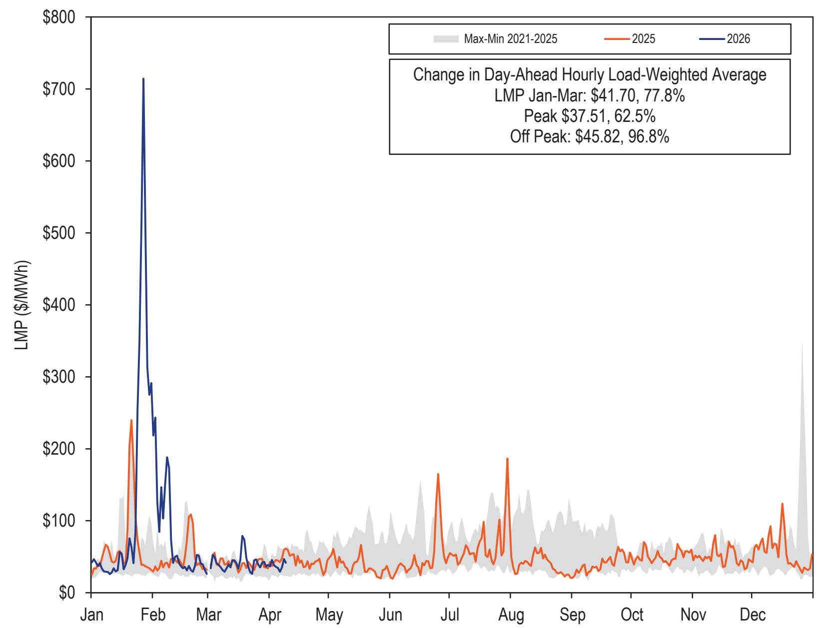


Figure 3-34 shows the day-ahead daily load-weighted average LMP in January 2025 through March 2026 compared to the historic five year price range.

Figure 3-34 Day-ahead daily load-weighted average LMP: 2025 through March 2026



PJM Day-Ahead Monthly Inflation Adjusted Load-Weighted Average LMP

Figure 3-35 shows the PJM day-ahead monthly load-weighted average LMP and inflation adjusted monthly day-ahead load-weighted average LMP for June 2000 through March 2026.[81] [82] Table 3-45 shows the PJM day-ahead load-weighted average LMP and inflation adjusted load-weighted average LMP for the first three months every year from 2001 through 2026.

81 To obtain the inflation adjusted monthly load-weighted average LMP, the PJM system-wide load-weighted average LMP is deflated using 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> (Accessed April 11, 2026).

82 The U.S. Bureau of Labor Statistics did not publish CPI data for October 2025. October 2025 CPI data was approximated using the geometric mean of September and November 2025 index values. Further information on approximating BLS data for missing data points can be found at: <https://www.bls.gov/cpi/factsheets/approximating-missing-data.htm>.

Figure 3-35 Day-ahead monthly load-weighted and inflation adjusted load-weighted average LMP: June 2000 through March 2026

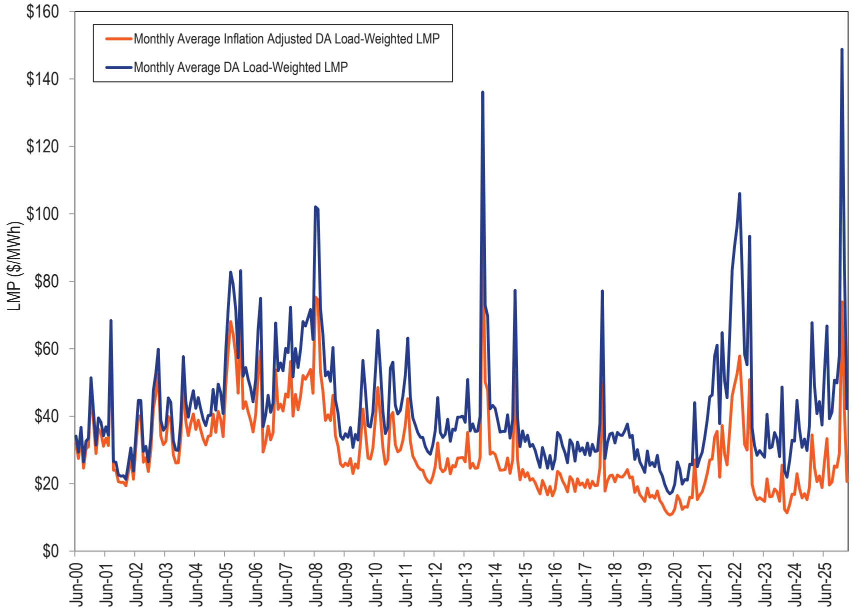


Table 3-45 Day-ahead yearly load-weighted and inflation adjusted load-weighted average LMP: January through March, 2001 through 2026

	Load-Weighted Average LMP	Inflation Adjusted Load-Weighted Average LMP
	Jan-Mar	Jan-Mar
2001	$37.70	$34.68
2002	$23.17	$21.04
2003	$53.16	$46.94
2004	$47.75	$41.47
2005	$46.54	$39.19
2006	$52.40	$42.57
2007	$54.87	$43.51
2008	$68.00	$51.82
2009	$49.44	$37.71
2010	$47.77	$35.59
2011	$47.14	$34.41
2012	$31.51	$22.35
2013	$37.26	$25.98
2014	$94.97	$65.40
2015	$52.02	$35.80
2016	$27.94	$19.03
2017	$30.40	$20.18
2018	$47.55	$30.93
2019	$30.76	$19.66
2020	$20.12	$12.59
2021	$31.58	$19.40
2022	$54.23	$30.91
2023	$32.16	$17.30
2024	$32.34	$16.87
2025	$53.60	$27.19
2026	$95.30	$47.19

Price Convergence

The introduction of the PJM Day-Ahead Energy Market with virtuals as part of the design created the possibility that competition, exercised through the use of virtual offers and bids, could tend to cause prices in the day-ahead and real-time energy markets to converge more than would be the case without virtuals. Convergence is not the goal of virtual trading, but it is a possible outcome.

In practice, virtuals can receive a positive profit whenever there is a difference in prices at any location in any hour between the day-ahead and real-time energy markets that is greater than uplift and administrative charges.

Virtual trading can only result in price convergence at a given location and market hour if the factors affecting prices at that location and hour, such as modeled contingencies, transmission constraint limits and sources of flows, are the same in both the day-ahead and real-time models.

Where arbitrage incentives are created by systematic modeling differences, such as differences between the day-ahead and real-time modeled transmission contingencies and marginal loss calculations, virtual bids and offers cannot result in more efficient market outcomes. Such offers may result in positive profits for the virtual but cannot change the underlying reason for the price difference. The virtual transactions will continue to profit from the activity for that reason regardless of the volume of those transactions and without improving the efficiency of the energy market. This is termed false arbitrage.

The degree of convergence, by itself, is not a measure of the competitiveness or effectiveness of the day-ahead energy market. Price convergence does not necessarily mean a zero or even a very small difference in prices between day-ahead and real-time energy markets. There may be factors, from uplift charges to differences in risk that result in a competitive, market-based differential. In addition, convergence in the sense that day-ahead and real-time prices are equal at individual buses or aggregates on a day to day basis is not a realistic expectation as a result of uncertainty, lags in response time and modeling differences.

INCs, DECs and UTCs allow participants to benefit from price differences between the day-ahead and real-time energy market. In theory, virtual transactions receive positive profits, after uplift and administrative charges, when they contribute to price convergence, but with false arbitrage, profits result with little or no price convergence. The seller of an INC must buy energy in the real-time energy market to fulfill the financial obligation to provide energy. If the day-ahead price for energy is higher than the real-time price for energy, after uplift and administrative charges, the INC is profitable. The buyer of a DEC must sell energy in the real-time energy market to fulfill the financial obligation to buy energy. If the day-ahead price for energy is lower than the real-time price for energy, after uplift and administrative charges, the DEC is profitable.

The profit of a UTC transaction is the net of the separate revenues of the component INC and DEC, after uplift and administrative charges. A UTC can be profitable if the profits on one side of the UTC transaction exceed the losses on the other side.

Virtual transactions, including UTCs since November 1, 2020, are required to pay uplift charges. Cleared INCs and DECs pay deviation charges based on the daily RTO and applicable regional operating reserve charge rates. DECs pay day-ahead operating reserve charges in addition to deviation charges. Cleared UTCs are treated, for uplift purposes, like DECs at the UTC sink point, and pay the regional and RTO deviation rates in addition to the day-ahead rate. Uplift charges for deviations may not apply if the virtual transaction is partially or fully offset by a corresponding real-time physical transaction at the same location.

In the day-ahead market, load bids are submitted by market buyers at aggregate pnodes, and PJM uses historic bus level load data to distribute the aggregate bids among the bus level pnodes that comprise the aggregate pnode. Effective December 14, 2023, PJM modified the method used to assign load bids to nodes from a single snapshot at 8:00 AM the week prior to the hourly demand data from one week prior to the Operating Day for each hour.[83]

Profitability of Virtual Transactions

The profit of a virtual transaction equals its net day-ahead and real-time energy market revenues minus uplift and administrative charges.

Table 3-46 shows, for cleared UTCs, the number of UTCs, the number of profitable UTCs, and the number of UTCs profitable at their source point, at their sink point, and at both source and sink points in the first three months of 2025 and 2026. In the first three months of 2026, 43.7 percent of all cleared

83 PJM Interconnection, L.L.C., Tariff Revisions to Improve the Determination of Day-Ahead Zonal Load Factors, Docket No. ER23-1529 (March 31, 2023).

UTC transactions were profitable. Of cleared UTC transactions, 63.1 percent were profitable on the source side and 35.2 percent were profitable on the sink side, but only 8.8 percent were profitable on both the source and sink side.

Table 3-46 Cleared UTCs with positive profits at source and sink points: January through March, 2025 and 2026[84]

(Jan-Mar)	Number of Cleared UTCs	Number of Profitable UTCs	Profitable at Source	Profitable at Sink	Profitable at Source and Sink	Share Profitable Overall	Share Profitable Source	Share Profitable Sink	Share Profitable Source and Sink
2025	1,764,608	739,663	1,089,735	661,460	152,683	41.9%	61.8%	37.5%	8.7%
2026	1,641,503	717,689	1,036,229	577,702	144,095	43.7%	63.1%	35.2%	8.8%

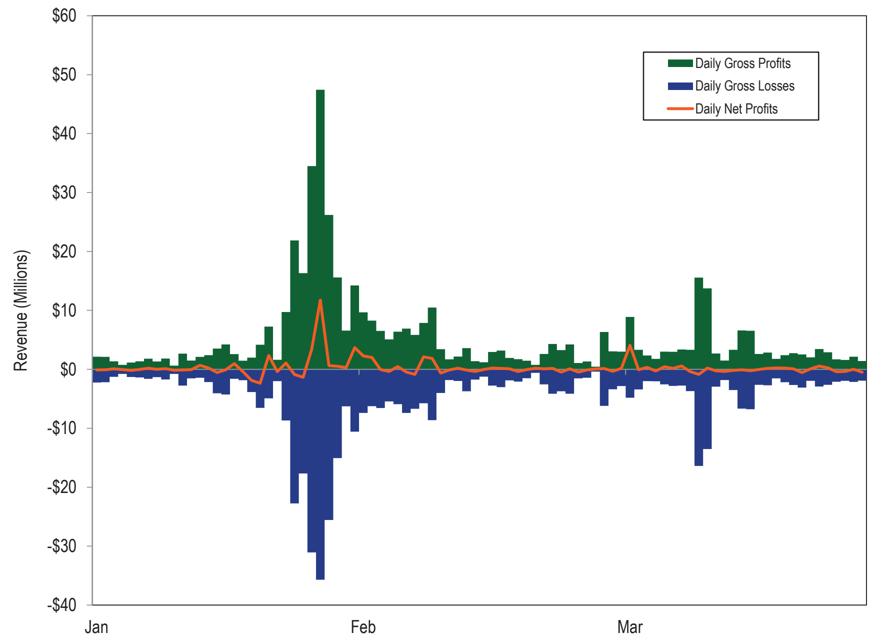
Table 3-47 shows the number of cleared INC and DEC transactions and the number of profitable transactions in the first three months of 2025 and 2026. Of cleared INC and DEC transactions in the first three months of 2026, 55.2 percent of INCs were profitable and 33.6 percent of DECs were profitable.

Table 3-47 Cleared INC and DEC transactions with positive profits: January through March, 2025 and 2026

(Jan-Mar)	Cleared INC	Profitable INC	Profitable INC Share	Cleared DEC	Profitable DEC	Profitable DEC Share
2025	1,226,046	622,188	50.7%	955,319	324,373	34.0%
2026	1,385,165	764,517	55.2%	1,112,772	374,404	33.6%

Figure 3-36 shows the positive, negative, and net daily profits for UTCs in the first three months of 2026.

Figure 3-36 Positive, negative, and net daily UTC profits: January through March, 2026



84 Calculations exclude PJM administrative charges.

Figure 3-37 shows the cumulative UTC daily total net profits for each year from 2013 through the first three months of 2026.[85] Administrative charges are included for all dates, and uplift charges are included starting from November 1, 2020, when uplift was first charged to UTCs.

Figure 3-37 Cumulative daily UTC profits: January 2013 through March 2026

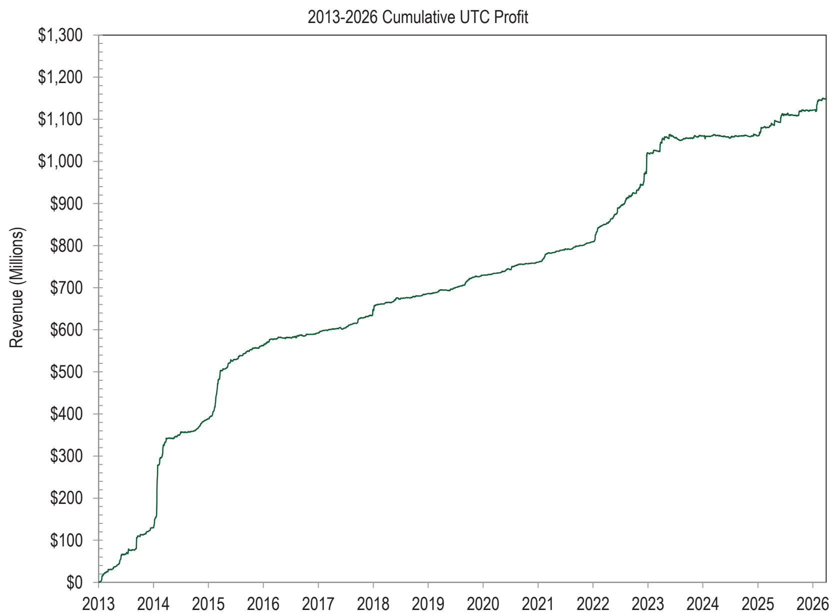


Table 3-48 shows UTC monthly total net profits for January 2013 through March 2026. Administrative charges are included for all months and uplift charges are included starting from November 1, 2020, when uplift was first charged to UTCs. UTC profits were $211 million in 2022, higher than any year since 2014, with the largest monthly total in December 2022 at $75 million. In 2023, the most profitable UTC transactions were concentrated in the Dominion Zone and on dates with high real-time congestion in the Dominion Zone, which occurred primarily in January through May, 2023. The year 2024 was the least profitable year ever for UTC transactions, with very large profitable days occurring with less frequency than prior years. DOMINION HUB to DOM_RESID_AGG UTC remains the path with the highest cleared volume in 2025 and the first three months of 2026. January 2026 was the most profitable month since June 2025.

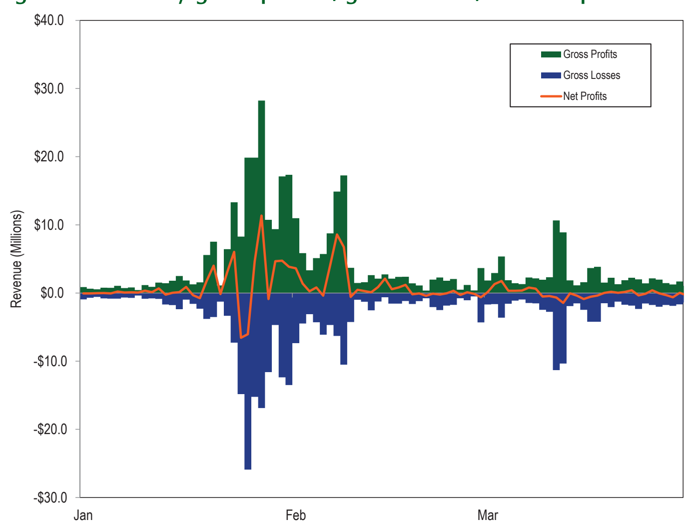
85 UTCs paid uplift only after October 31, 2020.

Table 3-48 UTC profits by month: January 2013 through March 2026

	January	February	March	April	May	June	July	August	September	October	November	December	Total
2013	$17,048,654	$8,304,767	$5,629,392	$7,560,773	$25,219,947	$3,484,372	$8,781,526	$2,327,168	$31,160,618	$4,393,583	$8,730,701	$6,793,990	$129,435,490
2014	$148,973,434	$23,235,621	$39,448,716	$1,581,786	$3,851,636	$7,353,460	$3,179,356	$287,824	$2,727,763	$10,889,817	$11,042,443	$6,191,101	$258,762,955
2015	$16,132,319	$53,830,098	$44,309,656	$6,392,939	$19,793,475	$824,817	$8,879,275	$5,507,608	$6,957,012	$4,852,454	$392,876	$6,620,581	$174,493,110
2016	$8,874,363	$6,118,477	$1,119,457	$2,768,591	($1,333,563)	$841,706	$3,128,346	$3,200,573	($2,518,408)	$4,216,717	$254,684	$3,271,368	$29,942,312
2017	$5,716,757	($17,860)	$3,083,167	$944,939	$1,245,988	$868,400	$7,053,390	$4,002,063	$10,960,012	$2,360,817	$2,716,950	$15,936,217	$54,870,839
2018	$13,184,346	$506,509	$3,410,577	$688,796	$9,499,735	($768,614)	$1,163,380	$692,736	$2,845,649	$1,452,515	$4,339,363	$1,358,446	$38,373,436
2019	$574,901	$2,407,307	$5,287,985	$332,036	$1,833,879	$3,382,009	$4,066,461	$2,442,971	$12,599,278	$5,914,042	$1,171,145	$3,722,403	$43,734,418
2020	$664,972	$2,497,856	$1,720,037	$1,865,139	$5,508,276	$1,123,429	$8,573,276	$3,957,296	($141,240)	$1,628,186	$1,170,367	$2,319,727	$30,887,320
2021	$6,421,567	$13,241,294	$1,788,961	$4,529,921	$2,542,898	$3,384,291	($1,199,849)	$5,330,600	$2,649,331	$2,148,861	$5,091,590	$2,665,873	$48,595,339
2022	$30,954,077	$7,236,325	$4,411,627	$11,317,095	$11,658,586	$16,398,181	$9,481,970	$17,376,381	$6,783,480	$7,325,933	$13,116,641	$75,067,601	$211,127,897
2023	($374,877)	$5,180,921	$18,722,180	$13,543,116	$5,121,917	($6,820,656)	($5,587,077)	$3,667,565	$1,041,650	$787,185	$3,734,966	$1,259,381	$40,276,272
2024	($798,085)	$741,801	$505,530	($1,048,989)	($1,481,223)	($1,997,609)	$3,605,145	($28,816)	$440,898	($852,701)	$472,000	$677,521	$235,473
2025	$19,307,539	$965,550	$9,446,437	$5,569,957	($1,921,483)	$17,309,458	($1,634,565)	($406,499)	$1,936,052	$10,057,277	($1,107,552)	$1,903,108	$61,425,280
2026	$17,417,904	$5,488,600	$2,880,710										$25,787,213

Figure 3-38 shows the positive, negative, and net daily profits for INCs and DECs in the first three months of 2026. Differences in the modeling of transmission constraints between day ahead and real time, including the use of different constraint limits or a constraint being modeled in one market but not the other, remain a principal source of false arbitrage profits and a major reason for the overall profitability of virtual transactions.

Figure 3-38 Daily gross profits, gross losses, and net profits of all INC and DEC transactions: January through March, 2026[86]



86 Calculations exclude PJM administrative charges.

Figure 3-39 shows the positive, negative, and net daily profits for INCs in the first three months of 2026.

Figure 3-39 Daily gross profits, gross losses, and net profits for INC transactions: January through March, 2026[87]

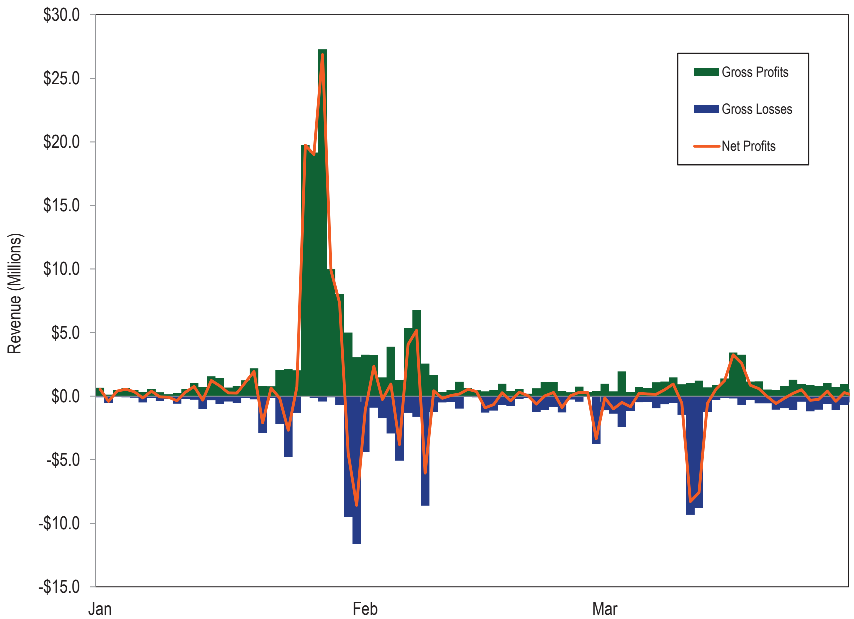
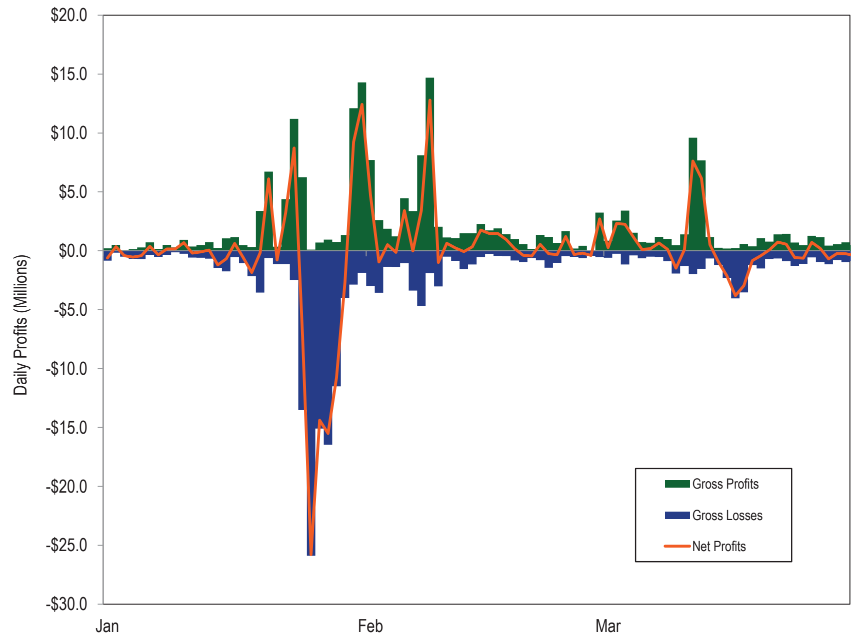


Figure 3-40 shows the positive, negative, and net daily profits for DECs in the first three months of 2026.

Figure 3-40 Daily gross profits, gross losses, and net profits for DEC transactions: January through March, 2026



87 Calculations exclude PJM administrative charges.

Figure 3-41 shows the cumulative INC and DEC daily profits in the first three months of 2026. Virtual trading can be profitable without contributing to price convergence because the addition of virtual supply or demand in the day-ahead market does not and cannot correct for factors not included in the day-ahead model, such as the use of different transmission constraint limits in day ahead versus real time.

Figure 3-41 Cumulative daily INC and DEC profit: January through March, 2026

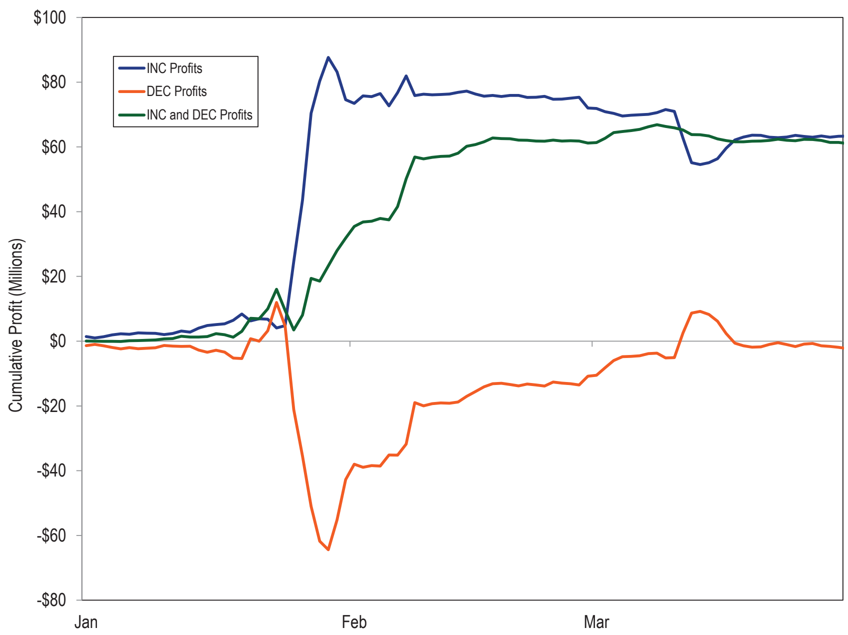


Table 3-49 shows INC and DEC profits in the first three months of 2026.

Table 3-49 INC and DEC profits by month: January through March, 2026

Month	INCs	DECs	INCs and DECs
January	$83,154,854	($55,180,500)	$27,974,354
February	($7,806,345)	$41,661,603	$33,855,258
March	($12,007,422)	$11,249,436	($757,986)
Total	$63,341,087	($2,269,461)	$61,071,626

All virtual transactions are subject to uplift charges. Each cleared MWh of a virtual transaction pays uplift at the daily operating reserve charge rates, but UTCs pay uplift only at the transaction sink. Cleared increment offers pay the regional and RTO deviation rates, and cleared decrement bids pay the day-ahead rate in addition. Cleared up to congestion transactions pay the same rate as a decrement bid but only at the transaction's sink point. DECs and UTCs pay the day-ahead rate and RTO and regional deviation rates.

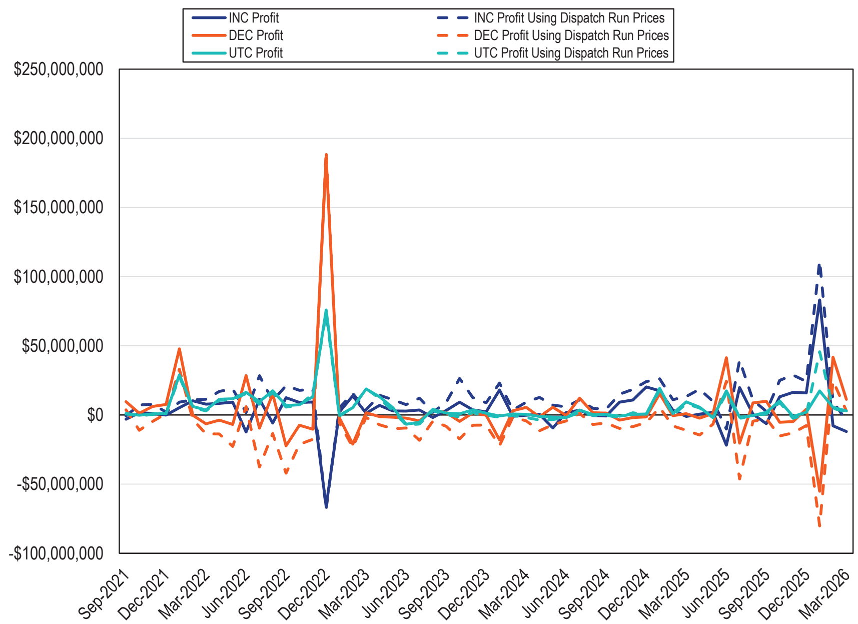
In the first three months of 2026, INCs paid a total of $17.8 million, DECs paid a total of $25.4 million, and UTCs paid a total of $36.3 million in uplift. This compares to total INC profits of $63.3 million, total DEC losses of $2.3 million, and total UTC profits of $25.8 million.

Effect of Fast Start Pricing on Virtuals

The implementation of fast start pricing on September 1, 2021, has resulted in changes to the settlement of virtual transactions. Prior to fast start pricing, virtual products were cleared and settled based on a single set of prices. The dispatch and pricing run prices were the same. With fast start pricing, all virtual products are cleared using day-ahead dispatch run prices, but pay and receive the day-ahead and real-time pricing run prices. The use of fast start pricing has a direct effect on virtual settlements through the use of prices different from those used to dispatch virtuals. This means that a DEC may clear in the day-ahead market, based on the dispatch run, even though its offer is lower than the final, pricing run price. This means that an INC may clear even though its offer is higher than the day-ahead market price. The use of fast start pricing also results in divergence between day-ahead and real-time prices, which can be targeted by virtual traders. The fact that fast start pricing increases prices more in the real-time market, all else held equal, increases the profitability of DECs and decreases the profitability of INCs.

Figure **3-42** shows the total monthly profits received by INCs, DECs, and UTCs, compared to the profits they would have received if dispatch run prices had been used in settlement for each month since the initial implementation of fast start pricing in September 2021. Since its implementation, fast start pricing has consistently increased profits for DECs and decreased profits for INCs but has not significantly affected profits for UTCs. Fast start pricing creates a difference between day-ahead and real-time prices. Virtual traders can benefit from this difference without contributing to price convergence.

Figure 3-42 Monthly profits for virtuals using pricing run versus dispatch run prices: September 1, 2021 through March 31, 2026



From the implementation of fast start pricing on September 1, 2021, through December 31, 2025, the cumulative difference in profit between the pricing run and the dispatch run for INCs was -$473.5 million, the cumulative difference in profit for DECs was $579.7 million, and the cumulative difference in profit for UTCs was $21.8 million. Fast start pricing led to a net increase of $128.1 million in cumulative profits for virtual transactions since September 1, 2021.

There are incentives to use virtual transactions to profit from price differences between the day-ahead and real-time energy markets, but there is no reason to believe that such activity will result in price convergence and no data to support that claim. As a general matter, virtual offers and bids are based on expectations about both day-ahead and real-time energy market conditions and reflect the uncertainty about conditions in both markets, about modeling differences and the fact that these conditions change hourly and daily. PJM markets do not provide a mechanism that could result in immediate convergence after a change in system conditions as there is at least a one day lag after any change in system conditions before offers could reflect such changes. PJM markets do not provide a mechanism that could ever result in convergence in the presence of modeling differences.

Substantial virtual trading activity does not guarantee that market power cannot be exercised in the day-ahead energy market. Hourly and daily price differences between the day-ahead and real-time energy markets fluctuate continuously and substantially from positive to negative. There may be substantial, persistent differences between day-ahead and real-time prices even on a monthly basis.

Day-ahead and Real-time Prices

Table 3-50 shows the difference between the day-ahead and the real-time average LMP in the first three months of 2025 and 2026.

Table 3-50 Day-ahead and real-time average LMP (Dollars per MWh): January through March, 2025 and 2026[88]

	2025 (Jan-Mar)				2026 (Jan-Mar)			
	Day-Ahead	Real-Time	Difference	Percent of Real Time	Day-Ahead	Real-Time	Difference	Percent of Real Time
Average	$50.27	$49.17	($1.10)	(2.2%)	$84.40	$77.78	($6.62)	(8.5%)
Median	$39.11	$37.99	($1.12)	(2.9%)	$39.57	$37.24	($2.33)	(6.3%)
Standard deviation	$37.66	$36.17	($1.49)	(4.1%)	$123.91	$110.80	($13.11)	(11.8%)
Peak average	$56.54	$54.72	($1.82)	(3.3%)	$87.90	$73.35	($14.55)	(19.8%)
Peak median	$43.20	$42.37	($0.83)	(2.0%)	$43.70	$41.29	($2.41)	(5.8%)
Peak standard deviation	$44.17	$41.49	($2.68)	(6.5%)	$137.24	$98.07	($39.17)	(39.9%)
Off peak average	$44.78	$44.32	($0.46)	(1.0%)	$81.33	$81.66	$0.33	0.4%
Off peak median	$36.39	$35.33	($1.06)	(3.0%)	$36.57	$34.38	($2.19)	(6.4%)
Off peak standard deviation	$29.80	$29.94	$0.13	0.4%	$110.90	$120.76	$9.86	8.2%

Table 3-51 shows the difference between the day-ahead and the real-time load-weighted LMP in the first three months of 2001 through 2026.

Table 3-51 Day-ahead and real-time load-weighted average LMP (Dollars per MWh): January through March, 2001 through 2026

	Load-Weighted Average LMP					
Jan-Mar	Day-Ahead	Real-Time	Difference	Percent of Real-Time	Average Absolute Difference	Average Absolute Difference as a Percent of Real-Time
2001	$37.70	$35.16	($2.54)	(7.2%)	$12.39	35.2%
2002	$23.17	$23.01	($0.15)	(0.7%)	$4.37	19.0%
2003	$53.16	$51.93	($1.23)	(2.4%)	$17.01	32.8%
2004	$47.75	$48.77	$1.02	2.1%	$11.61	23.8%
2005	$46.54	$48.37	$1.84	3.8%	$9.84	20.3%
2006	$52.40	$54.43	$2.03	3.7%	$12.58	23.1%
2007	$54.87	$58.07	$3.20	5.5%	$16.16	27.8%
2008	$68.00	$69.35	$1.35	2.0%	$17.96	25.9%
2009	$49.44	$49.60	$0.16	0.3%	$7.96	16.1%
2010	$47.77	$45.92	($1.85)	(4.0%)	$9.21	20.0%
2011	$47.14	$46.35	($0.79)	(1.7%)	$9.31	20.1%
2012	$31.51	$31.21	($0.30)	(1.0%)	$4.11	13.2%
2013	$37.26	$37.41	$0.15	0.4%	$5.88	15.7%
2014	$94.97	$92.98	($1.99)	(2.1%)	$34.95	37.6%
2015	$52.02	$50.91	($1.11)	(2.2%)	$13.19	25.9%
2016	$27.94	$26.80	($1.14)	(4.3%)	$4.94	18.4%
2017	$30.40	$30.28	($0.12)	(0.4%)	$4.51	14.9%
2018	$47.55	$49.45	$1.89	3.8%	$11.03	22.3%
2019	$30.76	$30.16	($0.60)	(2.0%)	$4.84	16.0%
2020	$20.12	$19.85	($0.27)	(1.3%)	$2.50	12.6%
2021	$31.58	$30.84	($0.74)	(2.4%)	$6.23	20.2%
2022	$54.23	$54.13	($0.10)	(0.2%)	$11.75	21.7%
2023	$32.16	$30.28	($1.88)	(6.2%)	$6.65	22.0%
2024	$32.34	$31.01	($1.33)	(4.3%)	$8.35	26.9%
2025	$53.60	$52.20	($1.40)	(2.7%)	$12.89	24.7%
2026	$95.30	$87.57	($7.73)	(8.8%)	$32.33	36.9%

88 The averages used are the annual average of the hourly average PJM prices for day-ahead and real-time.

Table 3-52 includes frequency distributions of the differences between the day-ahead and the real-time load-weighted LMP in the first three months of 2025 and 2026.

Table 3-52 Frequency distribution by hours of real-time load-weighted LMP minus day-ahead load-weighted LMP (Dollars per MWh): January through March, 2025 and 2026

	2025 Jan - Mar		2026 Jan - Mar	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($200)	1	0.0%	62	2.9%
($200) to ($100)	21	1.0%	31	4.3%
($100) to ($50)	34	2.6%	54	6.8%
($50) to $0	1,256	60.8%	1,313	67.6%
$0 to $50	795	97.6%	567	93.9%
$50 to $100	38	99.4%	77	97.5%
$100 to $200	13	100.0%	28	98.7%
$200 to $400	1	100.0%	18	99.6%
$400 to $800	0	100.0%	8	100.0%
>= $800	0	100.0%	1	100.0%

Figure 3-43 shows the differences between day-ahead and real-time hourly average LMP in the first three months of 2026.

Figure 3-43 Real-time hourly average LMP minus day-ahead hourly average LMP: January through March, 2026

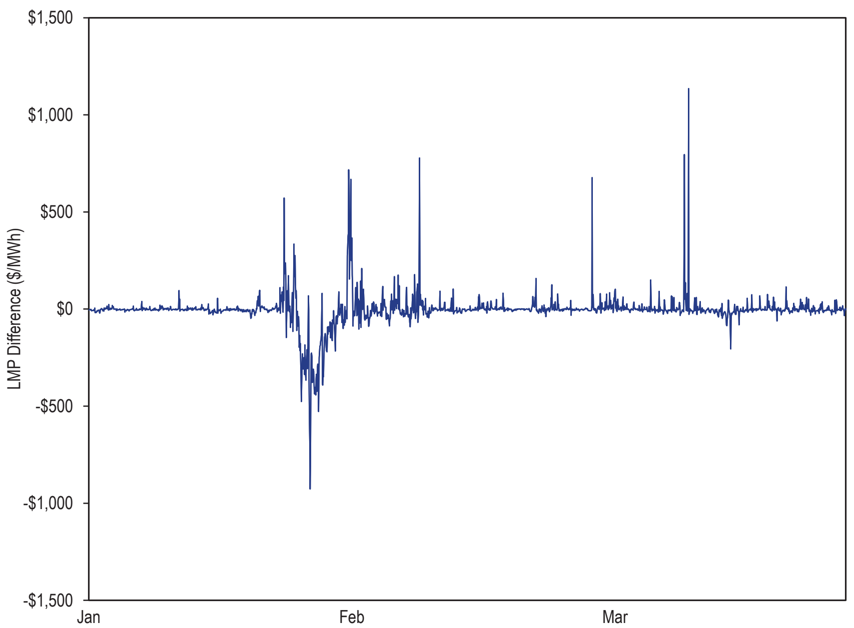
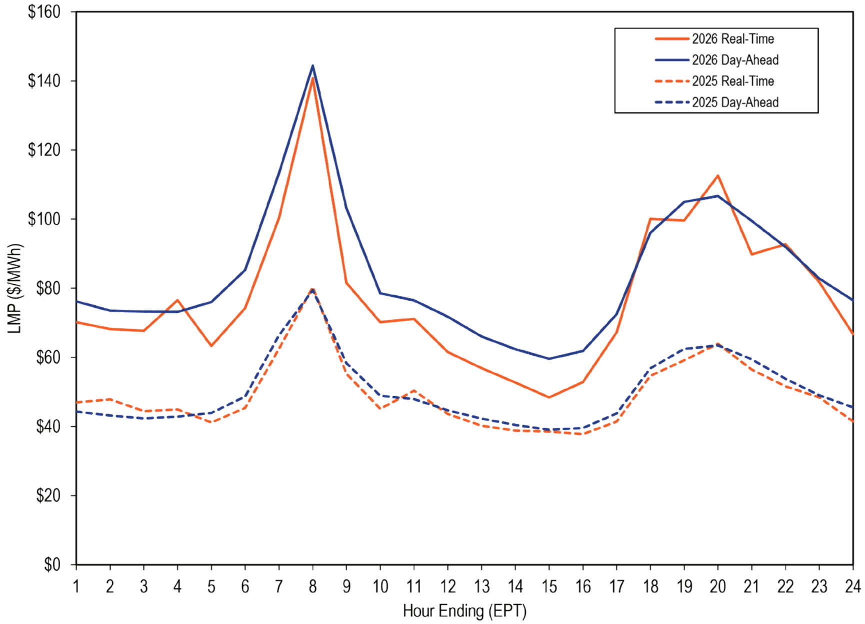


Figure 3-44 shows day-ahead and real-time load-weighted average LMP by hour of the day in the first three months of 2025 and 2026.

Figure 3-44 System hourly average LMP: January through March, 2025 and 2026



Zonal LMP and Dispatch

Table 3-53 shows real-time zonal average and load-weighted average LMP for the first three months of 2025 and 2026.

Table 3-53 Real-time zonal average and load-weighted average LMP (Dollars per MWh): January through March, 2025 and 2026

	Real-Time Average LMP			Real-Time Load-Weighted Average LMP		
	2025	2026		2025	2026	
Zone	Jan-Mar	Jan-Mar	Percent Change	Jan-Mar	Jan-Mar	Percent Change
ACEC	$46.28	$71.45	54.4%	$49.62	$81.92	65.1%
AEP	$48.31	$67.22	39.2%	$50.81	$73.05	43.8%
APS	$51.60	$96.07	86.2%	$55.24	$111.40	101.7%
ATSI	$46.97	$61.03	29.9%	$48.40	$64.48	33.2%
BGE	$58.50	$113.43	93.9%	$64.49	$136.38	111.5%
COMED	$31.61	$34.31	8.5%	$33.31	$36.12	8.4%
DAY	$46.23	$64.90	40.4%	$48.40	$70.57	45.8%
DUKE	$44.31	$63.72	43.8%	$46.49	$70.50	51.6%
DOM	$60.86	$110.28	81.2%	$66.35	$131.10	97.6%
DPL	$49.14	$78.69	60.2%	$54.40	$97.68	79.6%
DUQ	$46.08	$59.98	30.2%	$47.32	$64.03	35.3%
EKPC	$46.77	$64.90	38.7%	$51.83	$77.81	50.1%
JCPLC	$47.68	$72.47	52.0%	$50.65	$82.28	62.5%
MEC	$48.42	$73.71	52.2%	$51.19	$82.63	61.4%
OVEC	$42.03	$60.45	43.8%	$42.86	$63.53	48.2%
PECO	$45.48	$70.33	54.6%	$48.51	$81.08	67.1%
PE	$53.81	$69.49	29.1%	$56.04	$76.00	35.6%
PEPCO	$58.34	$115.82	98.5%	$64.59	$141.62	119.3%
PPL	$44.89	$71.36	59.0%	$47.70	$82.13	72.2%
PSEG	$49.05	$74.34	51.6%	$51.74	$82.47	59.4%
REC	$53.57	$77.46	44.6%	$55.95	$84.08	50.3%
PJM	$49.17	$77.78	58.2%	$52.20	$87.57	67.8%

Table 3-54 shows day-ahead zonal average and load-weighted average LMP in the first three months of 2025 and 2026.

Table 3-54 Day-ahead zonal average and load-weighted average LMP (Dollars per MWh): January through March, 2025 and 2026

	Day-Ahead Average LMP			Day-Ahead Load-Weighted Average LMP		
	2025	2026		2025	2026	
Zone	Jan-Mar	Jan-Mar	Percent Change	Jan-Mar	Jan-Mar	Percent Change
ACEC	$49.82	$80.01	60.6%	$53.56	$91.59	71.0%
AEP	$49.25	$73.09	48.4%	$52.15	$80.74	54.8%
APS	$51.98	$101.31	94.9%	$55.33	$116.30	110.2%
ATSI	$49.87	$69.89	40.2%	$51.78	$74.66	44.2%
BGE	$59.32	$119.74	101.9%	$64.67	$143.89	122.5%
COMED	$35.24	$51.13	45.1%	$37.23	$55.34	48.7%
DAY	$49.26	$73.64	49.5%	$52.03	$81.48	56.6%
DUKE	$47.36	$71.71	51.4%	$50.38	$80.74	60.2%
DOM	$57.76	$110.47	91.2%	$63.16	$132.92	110.5%
DPL	$52.39	$86.70	65.5%	$58.59	$106.54	81.8%
DUQ	$47.64	$66.50	39.6%	$49.56	$71.54	44.4%
EKPC	$47.67	$72.09	51.2%	$53.77	$91.36	69.9%
JCPLC	$50.81	$81.48	60.4%	$54.05	$92.18	70.6%
MEC	$52.17	$83.57	60.2%	$55.47	$92.69	67.1%
OVEC	$45.68	$69.41	52.0%	$39.20	$39.49	0.7%
PECO	$48.90	$78.48	60.5%	$52.43	$90.85	73.3%
PE	$55.66	$79.04	42.0%	$57.60	$79.63	38.2%
PEPCO	$59.20	$120.72	103.9%	$64.85	$147.66	127.7%
PPL	$47.95	$81.05	69.0%	$51.24	$92.45	80.4%
PSEG	$50.97	$82.98	62.8%	$53.48	$88.94	66.3%
REC	$54.81	$85.12	55.3%	$55.72	$89.17	60.0%
PJM	$50.27	$84.40	67.9%	$53.60	$95.30	77.8%

Figure 3-45 is a map of the real-time load-weighted average LMP for the first three months of 2026. In the legend, green represents the real-time load-weighted average LMP for the first three months of 2026 and each increment to the right represents five percent of the pricing nodes above the real-time load-weighted average LMP for the first three months of 2026 and each increment to the left represents 25 percent of the pricing nodes below the real-time load-weighted average LMP for the first three months 2026.

Figure 3-45 Real-time load-weighted average LMP: January through March, 2026

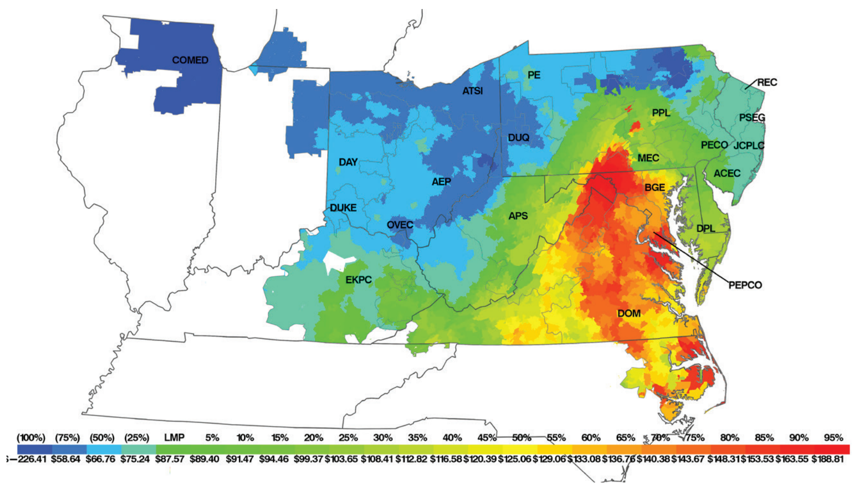
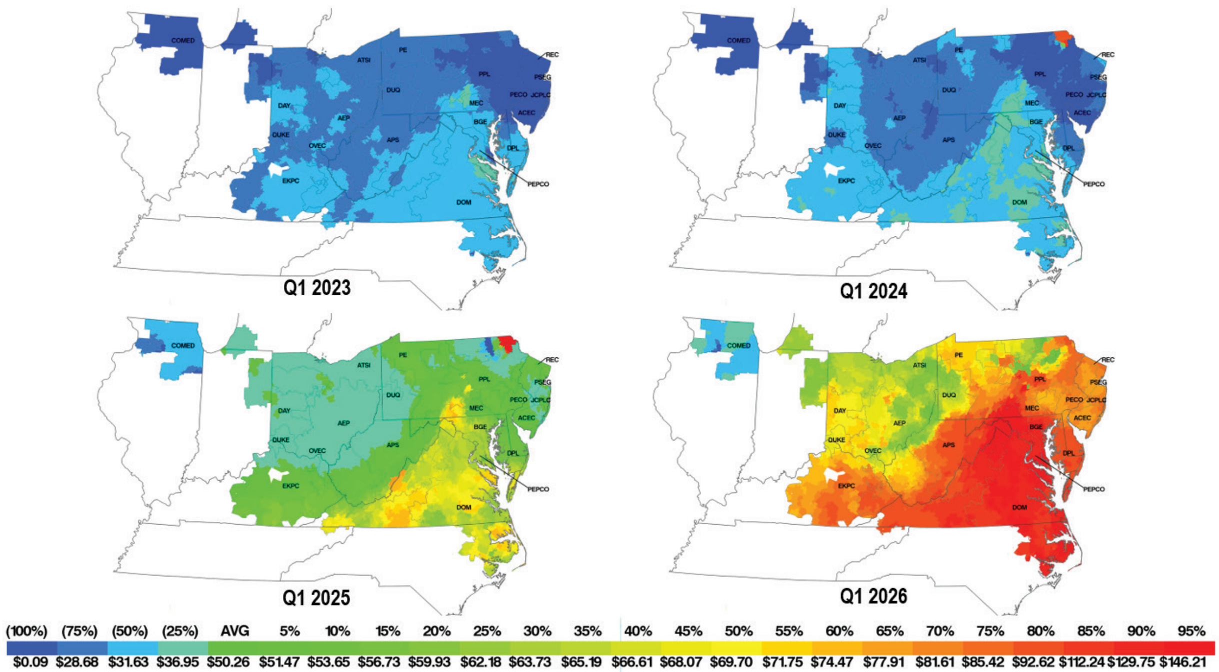


Figure 3-46 includes maps of the real-time load-weighted average LMP for the first three months of 2023 through 2026. In the legend, green represents the average price and each color increment to the right represents five percent of the pricing nodes above the average price and each color increment to the left represents 25 percent of the pricing nodes below the average price. The scale is based on prices for the first three months of all four years.

Figure 3-46 Real-time load-weighted average LMP map: January through March, 2023 through 2026



Transmission Constraint Penalty Factors (TCPF)

LMPs are generally set by the offer prices of marginal resources. When a transmission constraint is binding, the flow on the constraint is equal to its limit and the shadow price of the constraint is a function of offer prices of marginal resources. LMP may, at times, be set by transmission constraint penalty factors. When a transmission constraint is limiting and there are no generation alternatives to resolve the constraint, system operators may allow the transmission limit to be violated. When this occurs, the shadow price of the constraint is set by transmission constraint penalty factors. The shadow price directly affects the LMP. Transmission constraint penalty factors are administratively determined and can be thought of as a form of locational scarcity pricing, but only when properly applied. The TCPFs are applied incorrectly about 94 percent of the time. In addition, it is not clear that the line ratings are correctly defined, by duration of the flow and ambient conditions, by the transmission owners who have sole control over the line ratings with no meaningful oversight.

PJM operators routinely reduce the control limits on transmission constraint line ratings used in the market clearing software (SCED) by setting the control limits to 95 percent of the actual line ratings.[89] The result is that transmission constraint penalty factors set price much more frequently than needed or appropriate. PJM reduces the control limits both to control for actual flows and for flows that would only result from a contingency (N-1).

Since the implementation of fast start pricing on September 1, 2021, PJM set the default level of the transmission constraint penalty factor in the pricing run of the day-ahead market at $2,000 per MWh. The default level of the transmission constraint penalty factor in the dispatch run of the day-ahead market was left unchanged at $30,000 per MWh.

Table 3-55 shows the frequency and average shadow price of transmission constraints in the PJM real-time market. In the first three months of 2026, there were 74,351 transmission constraint five minute intervals in the real-time market with a nonzero shadow price. For 13,054, or 17.6 percent, of these transmission constraint intervals, the control limit was violated, meaning that the flow exceeded the facility limit used in SCED.[90] The data on violations includes both violations that result from reductions in the SCED control limit by PJM and violations that are based on the actual line ratings. Of the 13,054 constraint intervals, PJM used the actual line limits for 796 or 1.1 percent of the constraint intervals. For the remaining 12,258 or 16.5 percent of the constraint intervals, PJM used reduced line limits. In those cases, the actual line limit was not violated. In all cases where violations resulted from reductions by PJM from actual line ratings the shadow prices and resulting LMPs were set by the violation penalty factors. In the first three months of 2026, the average shadow price of transmission constraints ($1,999.98 per MWh)) when the line limit used in SCED was violated with a reduced line limit was 6.6 times higher than when the transmission constraint was binding but not violated ($$304.42 per MWh) at its limit used in SCED.

Of the 13,054 violated transmission constraint intervals in the first three months of 2026, 5,821 or 45 percent of the transmission constraint violations were during the Winter Storm Fern between January 22, 2026 and January 30, 2026.

Market to Market Transmission Constraints are categorized separately because of the unique rules governing the congestion management of these constraints by PJM and MISO. In the real-time market, PJM and MISO initiate a joint congestion management process commonly referred as “market to market” if they recognize substantial flows originating from the other RTO on their constraints. The identified constraints are then modeled in the dispatch optimizations of the both RTOs. After every approved solution, the shadow prices are exchanged between the RTOs.

Table 3-55 Frequency and average shadow price of transmission constraints in the real-time market: January through March, 2025 and 2026

	Frequency (Constraint Intervals)		Average Shadow Price	
Description	2025 (Jan - Mar)	2026 (Jan - Mar)	2025 (Jan - Mar)	2026 (Jan - Mar)
Violated Transmission Constraints (Actual)	358	796	$481.13	$876.12
Violated Transmission Constraints (Reduced Limit)	4,160	12,258	$1,989.27	$1,999.98
Binding Transmission Constraints	39,017	31,761	$323.45	$304.42
Market to Market Transmission Constraints	16,564	29,536	$483.82	$418.14
All Transmission Constraints	60,099	74,351	$483.90	$635.25

89 Actual transmission line limits are set by the transmission owner. PJM chooses the control limits. At present the actual line rating methods are not reviewed by FERC, or PJM, or the MMU.

90 The line limit of a facility associated with a transmission constraint is not necessarily the rated line limit. In PJM, the dispatcher has the discretion to lower the rated line limit.

Table 3-56 shows the frequency and average shadow price of transmission constraints in the PJM day-ahead market. In the first three months of 2026, there were 20,417 transmission constraint hours in the day-ahead market with a nonzero shadow price. For 589, or 2.9 percent, of these transmission constraint hours, the line limit was violated, meaning that the flow exceeded the facility limit used in the day-ahead pricing run solution.

Table 3-56 Frequency and average shadow price of transmission constraints in the day-ahead market: January through March, 2025 and 2026

	Frequency (Constraint Intervals)		Average Shadow Price	
Description	2025 (Jan - Mar)	2026 (Jan - Mar)	2025 (Jan - Mar)	2026 (Jan - Mar)
Violated Transmission Constraints (Actual)	10	406	$2,000.00	$1,784.82
Violated Transmission Constraints (Reduced)	-	183	$0.00	$2,000.00
Binding Transmission Constraints	17,599	16,145	$89.49	$131.06
Market to Market Transmission Constraints	3,219	3,683	$176.11	$151.02
All Transmission Constraints	20,828	20,417	$103.79	$184.30

Table 3-57 shows the frequency of violated transmission constraints by voltage level in the real-time market. In the first three months of 2026, 44.8 percent of the violated transmission constraint intervals had a voltage level at or below 230 kV.

Of the 7,116 violated 500 kV transmission constraint intervals in the first three months of 2026, 3,606 or 51 percent of the 500 kV transmission constraint violations were during the Winter Storm Fern between January 22, 2026, and January 30, 2026. All else being equal, transmission constraint violations at higher voltage levels have a greater impact on market prices.

Table 3-57 Frequency of PJM violated transmission constraints in the real-time market by voltage: January through March, 2025 and 2026

	2025 (Jan - Mar)		2026 (Jan - Mar)	
Voltage	Frequency (Constraint Intervals)	Percent	Frequency (Constraint Intervals)	Percent
1 kV	-	0.0%	15	0.1%
69 kV	236	5.2%	294	2.3%
115 kV	2,181	48.3%	1,384	10.6%
138 kV	980	21.7%	1,633	12.5%
230 kV	721	16.0%	2,516	19.3%
345 kV	71	1.6%	91	0.7%
500 kV	282	6.2%	7,116	54.5%
765 kV	47	1.0%	5	0.0%
Total	4,518	100.0%	13,054	100.0%

Transmission constraint penalty factors should be applied without discretion, but not without additional rules that prevent unintended consequences. PJM adopted the MMU's recommendation to remove the constraint relaxation logic and allow transmission penalty factors to set prices in the day-ahead and real-time markets for all internal transmission constraints.[91] But the potential for prolonged and excessively high administrative pricing in the energy market due to transmission constraint penalty factors remains an issue that needs to be addressed. There can be situations in which the application of transmission penalty factors in real time for significant periods creates manipulation opportunities for virtuals and creates inefficient wealth transfers when market participants do not have the ability to react to the high prices either on the supply or demand side.[92] This could be the result of a lengthy planned transmission outage, for example.[93] It can also result from PJM reducing the control limit on the line rating in RT SCED below 100 percent of the actual line limit and triggering the transmission constraint penalty factor, while operating the system below the actual line limit for a prolonged period. PJM should not reduce the control limit on the transmission line ratings in SCED to trigger the inclusion of transmission constraint penalty factors in price. In addition, PJM has no information about the accuracy of the line ratings that are determined by each transmission owner. It is not clear whether the line

91 PJM applied a procedure that PJM termed constraint relaxation logic, under which a revised SCED dispatch solution was obtained with an artificially increased limit for the violated transmission facility. The logic typically resulted in reducing the shadow prices to be slightly below the defined constraint violation penalty factor.
92 See Comments of the Independent Market Monitor for PJM, Docket No. EL22-26-000 et al. (February 1, 2022); 178 FERC ¶ 61,104 (2022).
93 See *id.*

ratings that trigger the transmission constraint penalty factors are defined for the actual expected period of the power flow on the line. Line ratings vary significantly by duration of power flows, and by ambient conditions.

PJM also revised the tariff to list the conditions under which transmission constraint penalty factors would be changed from their default value of $2,000 per MWh. The new rules went into effect on February 1, 2019. The Commission approved the PJM and MISO joint filing to remove the constraint relaxation logic for market to market constraints on March 6, 2020. PJM and MISO implemented the changes to their dispatch software in the second half of 2020. On March 21, 2023, FERC approved new rules proposed by PJM to allow for reducing the transmission constraint penalty factors below the default $2,000 per MWh for constraints that are violated due to a transmission outage caused by the construction of upgrades to relieve congestion, for which limited generation resources are available to provide relief.[94]

PJM routinely, based on discretion, reduces the control limits on the transmission constraint line ratings modeled in SCED to below 100 percent, generally to 95 percent of the actual limit, administratively triggering the use of transmission constraint penalty factors.[95] The control limits set the limit of the constraint modeled in SCED. For example, in SCED, a transmission facility with a 100 MW line rating set at a 90 percent control limit would be modeled as a constraint with a limit of 90 MW. Table 3-58 shows the frequency of changes to the control limits for transmission constraints for binding and violated transmission constraints in the PJM real-time market. In the first three months of 2026, there were 12,258, or 94 percent, of 13,054 violated transmission constraint intervals in the real-time market with a control limit less than 100 percent. In the first three months of 2026, among the constraints with a reduced control limit, the constraint limit was reduced on average by 5.5 percent. In the first three months of 2026, there were 31,301, or 99 percent, of 31,761 binding transmission constraint intervals in the real-time market with a control limit less than 100 percent. By arbitrarily lowering transmission facility limits, PJM is not using the full transmission system capacity available to serve the load to achieve the least cost dispatch solution. The cost to serve the load and the load payments would be lower had PJM not reduced the transmission line ratings.

Table 3-58 Frequency of reduction in control limit of line ratings (constraint intervals) in the real-time market: January through March, 2025 and 2026

	Frequency (Constraint Intervals)		Constraints with Reduced Control Percent (Constraint Intervals)		Average Reduction (Percent)	
Description	2025 (Jan - Mar)	2026 (Jan - Mar)	2025 (Jan - Mar)	2026 (Jan - Mar)	2025 (Jan - Mar)	2026 (Jan - Mar)
Violated Transmission Constraints (Actual)	358	796	-	-	0.0%	0.0%
Violated Transmission Constraints (Reduced Limit)	4,160	12,258	4,160	12,258	5.9%	5.5%
Binding Transmission Constraints	39,017	31,761	37,424	31,301	6.5%	6.0%
Market to Market Transmission Constraints	16,564	29,536	6,343	16,329	8.6%	6.4%
All Transmission Constraints	60,099	74,351	47,927	59,888	6.7%	6.0%

Table 3-59 shows the reasons provided by the PJM operators for changing the control limit on the line rating for violated transmission constraints. In the first three months of 2026, of the 12,258 violated transmission constraint intervals with reduced control limits, no reason was provided for 10,247 cases, or 83.6 percent of all the cases. In 1,469 cases, or 12.0 percent, the control limits were reduced because the relief calculated by the SCED optimization was less than the operator's desired relief for the transmission constraint. Although there were no cases in the first three months of 2026, the control limits were reduced because PJM designates the constraint as a thermal surrogate. Thermal surrogate constraints are constraints that PJM activates and for which PJM generally reduces the line rating to enable specific resources called on to control a constraint to set 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. This practice has significant market effects by limiting economic power flows and increasing prices above the level that would exist if 100 percent of the actual line rating were used in clearing the market and setting energy market prices.

94 See 182 FERC ¶ 61,183 (March 21, 2023). The Commission approved PJM's proposed tariff revisions to allow PJM to lower transmission constraint penalty factors generally for any situation similar to the high prices caused by Lanexa-Dunnsville-Northern Neck line outage in the Northern Neck peninsula in Virginia.

95 Actual transmission line limits are set by the transmission owner. PJM chooses the control limits. At present the actual line rating methods are not reviewed by FERC, or PJM, or the MMU.

Table 3-59 PJM's reasons for reduction in control limits of line ratings (constraint intervals) in the real-time market: January through March, 2025 and 2026

	Constraint Intervals		Average Reduction (Percent)	
Reason	2025 (Jan - Mar)	2026 (Jan - Mar)	2025 (Jan - Mar)	2026 (Jan - Mar)
Modeled constraint is a thermal surrogate	13	-	52.2%	0.0%
No reason provided	2,936	10,247	4.7%	5.1%
Prepositioning of generation resources to support an operational requirement	123	90	8.9%	7.9%
Inadequate relief calculated by the SCED optimization	857	1,469	8.3%	7.4%
Transmission owner identified the flow on their constraint to be greater than PJM's calculated flow on the same constraint.	46	126	10.0%	8.5%
Power flow on the constraint is volatile due to various system conditions	185	326	7.5%	6.9%
All violated constraints	4,160	12,258	5.9%	5.5%

Table 3-60 shows the impact on LMP of PJM dispatchers reducing the control limit of line ratings of transmission constraints and causing artificial line limit violations.[96] The transmission constraint penalty factor contribution to the load-weighted average LMP in the first three months of 2026 was $13.76 per MWh or $2.93 billion of the total $18.6 billion cost of real-time load. This impact includes reductions to the line limits of violated constraints during Winter Storm Fern. If 100 percent of the line limits had been used for the PJM transmission constraints and everything else remained unchanged, fewer constraints would have been violated and the transmission penalty factor's contribution to the load-weighted average LMP would have decreased to $0.08 per MWh, a 99.4 percent reduction.

96 The MMU calculates the impact on system prices based on analysis using sensitivity factors. The transmission penalty factor contribution with actual line limits is not based on a counterfactual redispatch of the system. See Technical Reference for PJM Markets, "Calculation and Use of Generator Sensitivity/Unit Participation Factors," <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

Table 3-60 Real-time LMP effect of reduced control limits on transmission constraint line ratings (Dollars per MWh): January through March, 2025 and 2026

	Contribution to LMP	
Line Limit Scenario for Violated Constraints	2025 (Jan - Mar)	2026 (Jan - Mar)
Line Limits Reduced by PJM (Actual)	$4.03	$13.76
Hypothetical Use of Full Line Limits	$0.03	$0.08
Change in Contribution to LMP	($4.00)	($13.68)
Percent Change in Contribution to LMP	(99.3%)	(99.4%)

Table 3-61 shows the frequency of changes to the magnitude of transmission penalty factors for binding and violated transmission constraints in the PJM Real-Time Energy Market. In the first three months of 2025, there were 12,585, or 97 percent, of the total 13,054 violated transmission constraint intervals, which includes 327 violated transmission constraint intervals with actual line limits and 12,258 violated transmission constraint intervals with reduced line limits, in the real-time market with a transmission penalty factor equal to the default $2,000 per MWh.

Table 3-61 Frequency of changes to the magnitude of transmission penalty factor (constraint intervals) in the real-time market: January through March, 2025 and 2026

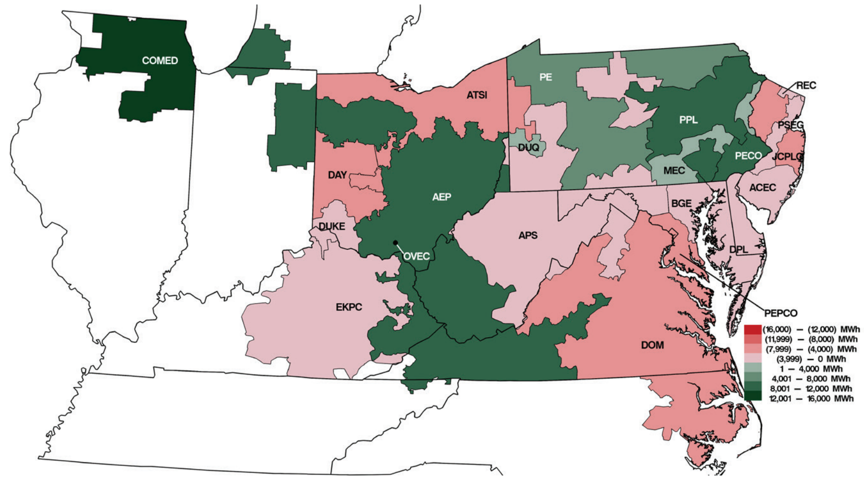
	2025 (Jan - Mar)			2026 (Jan - Mar)		
Description	$2,000 per MWh (Default)	Above $2,000 per MWh	Below $2,000 per MWh	$2,000 per MWh (Default)	Above $2,000 per MWh	Below $2,000 per MWh
Violated Transmission Constraints (Actual)	41	-	317	327	-	469
Violated Transmission Constraints (Reduced Limit)	4,147	-	13	12,258	-	-
Binding Transmission Constraints	37,565	-	1,452	31,511	-	250
Market to Market Transmission Constraints	6,451	14	10,099	2,592	28	26,916
All Transmission Constraints	48,204	14	11,881	46,688	28	27,635

Prior to September 1, 2022, transmission constraint penalty factors frequently set prices when PJM modeled a stability surrogate constraint to limit the dispatch of a generator that would experience voltage instability at its full output due to a transmission outage. Since September 1, 2022, PJM uses a generator output limit constraint to manage generator voltage instability issues. In the first three months of 2026, there were 27,013 constraint intervals during which PJM reduced the output of generators to manage instability. Changes to the surrogate constraint limit that exceed the unit's ability to reduce output cause constraint violations. Constraint violations also occur when the unit follows the regulation signal or increases its minimum operating parameters above the surrogate constraint limit. Prices set at the $2,000 per MWh penalty factor are not useful signals to the market under these conditions and create false arbitrage opportunities for virtuals.

Net Generation by Zone

Figure 3-47 shows the difference between the PJM real-time generation and real-time load by zone in the first three months of 2025. Figure 3-47 is color coded using a scale on which red shades represent zones that have less generation than load and green shades represent zones that have more generation than load, with darker shades meaning greater amounts of net generation or load. Table 3-62 shows the difference between the real-time generation and real-time load by zone in the first three months of 2025 and 2026.

Figure 3-47 Map of real-time generation less real-time load by zone: January through March, 2026[97]



97 Real-time zonal generation data for the map and corresponding table is based on the zonal designation for every bus listed in the most current PJM LMP bus model, which can be found at <http://www.pjm.com/markets-and-operations/energy/lmp-model-info.aspx>.

Table 3-62 Real-time generation less real-time load by zone (GWh): January through March, 2025 and 2026

	Zonal Generation and Load (GWh)					
	2025 (Jan-Mar)			2026 (Jan-Mar)		
Zone	Generation	Load	Net	Generation	Load	Net
ACEC	344	2,263	(1,919)	545	2,319	(1,774)
AEP	44,271	34,721	9,550	45,304	37,364	7,939
APS	12,486	13,325	(839)	13,419	13,490	(71)
ATSI	12,963	16,998	(4,034)	14,792	16,942	(2,151)
BGE	4,214	8,004	(3,789)	4,534	8,114	(3,579)
COMED	35,791	22,789	13,002	34,342	22,740	11,602
DAY	461	4,489	(4,028)	502	4,495	(3,993)
DUKE	3,967	6,694	(2,727)	3,973	6,585	(2,612)
DOM	28,365	32,994	(4,630)	28,663	35,285	(6,621)
DPL	1,209	4,963	(3,754)	1,463	5,114	(3,650)
DUQ	4,206	3,264	942	4,323	3,199	1,124
EKPC	2,872	4,019	(1,147)	2,897	4,018	(1,121)
JCPLC	1,161	5,230	(4,069)	1,590	5,432	(3,843)
MEC	4,882	3,994	888	4,137	4,086	51
OVEC	3,383	33	3,350	3,223	33	3,190
PECO	19,461	9,851	9,611	19,956	10,114	9,842
PE	8,668	4,365	4,303	7,833	4,388	3,445
PEPCO	2,358	7,259	(4,901)	2,775	7,329	(4,553)
PPL	19,747	11,082	8,665	20,063	11,234	8,829
PSEG	9,680	10,176	(496)	10,151	10,585	(434)
REC	0	321	(321)	0	332	(332)

Net Generation and Load

PJM sums all negative (injections) and positive (withdrawals) at each designated load bus when calculating net load (accounting load). PJM sums all of the negative (withdrawals) and positive (injections) at each generation bus when calculating net generation. Netting withdrawals and injections by bus type (generation or load) affects the measurement of total load and total generation. Energy withdrawn at a generation bus to provide, for example, auxiliary/parasitic power or station power, power to synchronous condenser motors, power to onsite customers, or power to run pumped storage pumps, is actually load, not negative generation. Energy injected at load buses by behind the meter generation is actually generation, not negative load.

The zonal load-weighted LMP is calculated by weighting the zone's load bus LMPs by the zone's load bus accounting load. The definition of injections and withdrawals of energy as generation or load affects PJM's calculation of zonal load-weighted LMP.

The MMU recommends that during intervals when a generation bus shows a net withdrawal, the energy withdrawal be treated as load, not negative generation, for purposes of calculating load and load-weighted LMP. The MMU also recommends that during intervals 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.

Fuel Prices, LMP, and Dispatch

Energy Production by Fuel Source

Table 3-63 shows PJM generation by fuel source in GWh for the first three months of 2025 and 2026.

In the first three months of 2026, generation from coal units decreased 1.7 percent, generation from natural gas units increased 4.2 percent, generation from oil units increased 43.2 percent, generation from wind units decreased 4.7 percent, and generation from solar units increased 15.0 percent compared to the first three months of 2025.

Table 3-63 Generation (By fuel source (GWh)): January through March, 2025 and 2026[98] [99]

	2025 (Jan-Mar)		2026 (Jan-Mar)		Change in
	GWh	Percent	GWh	Percent	Output
Coal	40,675.0	18.2%	39,973.1	17.6%	(1.7%)
Bituminous	34,324.6	15.4%	33,892.8	14.9%	(1.3%)
Sub Bituminous	4,603.4	2.1%	4,197.1	1.8%	(8.8%)
Other Coal	1,747.0	0.8%	1,883.2	0.8%	7.8%
Nuclear	68,374.1	30.6%	68,769.7	30.2%	0.6%
Gas	92,034.6	41.2%	95,911.3	42.1%	4.2%
Natural Gas CC	85,847.2	38.4%	86,038.9	37.8%	0.2%
Natural Gas CT	3,911.0	1.7%	5,673.7	2.5%	45.1%
Natural Gas Other Units	2,035.6	0.9%	3,964.4	1.7%	94.8%
Other Gas	240.9	0.1%	234.3	0.1%	(2.7%)
Hydroelectric	4,021.0	1.8%	3,921.5	1.7%	(2.5%)
Pumped Storage	1,532.9	0.7%	1,577.1	0.7%	2.9%
Run of River	2,098.5	0.9%	1,924.6	0.8%	(8.3%)
Other Hydro	389.5	0.2%	419.8	0.2%	7.8%
Wind	11,253.0	5.0%	10,725.5	4.7%	(4.7%)
Waste	945.3	0.4%	929.2	0.4%	(1.7%)
Oil	1,155.6	0.5%	1,655.4	0.7%	43.2%
Heavy Oil	79.9	0.0%	152.7	0.1%	91.2%
Light Oil	624.3	0.3%	975.3	0.4%	56.2%
Diesel	53.7	0.0%	125.9	0.1%	134.5%
Other Oil	397.8	0.2%	401.6	0.2%	1.0%
Solar	4,690.4	2.1%	5,396.0	2.4%	15.0%
Battery	16.2	0.0%	31.0	0.0%	90.6%
Biofuel	320.0	0.1%	299.3	0.1%	(6.5%)
Total	223,485.3	100.0%	227,611.8	100.0%	1.8%

98 All generation is total gross generation output and does not net out the MWh withdrawn at a generation bus to provide auxiliary/parasitic power or station power, power to synchronous condenser motors, power to run pumped hydro pumps or power to charge batteries.

99 Other Gas includes: Landfill, Propane, Butane, Hydrogen, Gasified Coal, and Refinery Gas. Other Coal includes: Lignite, Liquefied Coal, Gasified Coal, and Waste Coal. Other oil includes: Gasoline, Jet Oil, Kerosene, and Petroleum-Other.

Table 3-64 Monthly generation (By fuel source (GWh)): January through March, 2026

	Jan	Feb	Mar	Total
Coal	17,020.1	13,544.4	9,408.6	39,973.1
Bituminous	14,256.7	11,492.0	8,144.1	33,892.8
Sub Bituminous	2,109.5	1,410.2	677.5	4,197.1
Other Coal	653.9	642.2	587.0	1,883.2
Nuclear	24,959.6	21,526.0	22,284.1	68,769.7
Gas	35,496.0	32,024.7	28,390.5	95,911.3
Natural Gas CC	31,395.4	28,898.7	25,744.9	86,038.9
Natural Gas CT	2,422.4	1,855.5	1,395.7	5,673.7
Natural Gas Other Units	1,593.6	1,196.7	1,174.2	3,964.4
Other Gas	84.8	73.8	75.7	234.3
Hydroelectric	1,202.8	1,051.8	1,666.9	3,921.5
Pumped Storage	508.6	491.3	577.2	1,577.1
Run of River	557.9	430.6	936.2	1,924.6
Other Hydro	136.3	129.9	153.6	419.8
Wind	3,865.8	2,906.5	3,953.2	10,725.5
Waste	312.1	278.5	338.6	929.2
Oil	895.0	493.7	266.7	1,655.4
Heavy Oil	68.6	58.7	25.4	152.7
Light Oil	592.3	278.6	104.3	975.3
Diesel	93.8	31.8	0.3	125.9
Other Oil	140.2	124.7	136.7	401.6
Solar	1,337.0	1,689.6	2,369.4	5,396.0
Battery	9.8	9.5	11.6	31.0
Biofuel	123.4	115.4	60.5	299.3
Total	85,221.6	73,640.0	68,750.2	227,611.8

Table 3-65 shows the difference between the day-ahead and the real-time average generation by fuel source.

Table 3-65 Day-ahead and real-time average generation (By fuel source (GWh)): January through March, 2026

	2026 (Jan-Mar)					
	Day-Ahead		Real-Time			Percent
	GWh	Percent	GWh	Percent	RT - DA	Difference
Coal	40,805.7	18.1%	39,973.1	17.6%	(832.7)	(2.0%)
Bituminous	34,417.7	15.2%	33,892.8	14.9%	(525.0)	(1.5%)
Sub Bituminous	4,540.2	2.0%	4,197.1	1.8%	(343.1)	(7.6%)
Other Coal	1,847.8	0.8%	1,883.2	0.8%	35.4	1.9%
Nuclear	68,871.4	30.5%	68,769.7	30.2%	(101.7)	(0.1%)
Gas	95,996.3	42.5%	95,911.3	42.1%	(85.0)	(0.1%)
Natural Gas CC	86,825.3	38.5%	86,038.9	37.8%	(786.4)	(0.9%)
Natural Gas CT	4,882.0	2.2%	5,673.7	2.5%	791.7	16.2%
Natural Gas Other Units	4,044.1	1.8%	3,964.4	1.7%	(79.7)	(2.0%)
Other Gas	244.9	0.1%	234.3	0.1%	(10.6)	(4.3%)
Hydroelectric	3,854.9	1.7%	3,921.5	1.7%	66.6	1.7%
Pumped Storage	1,855.7	0.8%	1,577.1	0.7%	(278.6)	(15.0%)
Run of River	1,999.2	0.9%	1,924.6	0.8%	(74.6)	(3.7%)
Other Hydro	0.0	0.0%	419.8	0.2%	419.8	NA
Wind	8,457.1	3.7%	10,725.5	4.7%	2,268.3	26.8%
Waste	932.2	0.4%	929.2	0.4%	(3.1)	(0.3%)
Oil	1,600.7	0.7%	1,655.4	0.7%	54.7	3.4%
Heavy Oil	25.7	0.0%	152.7	0.1%	127.0	493.3%
Light Oil	1,022.8	0.5%	975.3	0.4%	(47.5)	(4.6%)
Diesel	159.3	0.1%	125.9	0.1%	(33.4)	(21.0%)
Other Oil	392.9	0.2%	401.6	0.2%	8.7	2.2%
Solar	4,822.7	2.1%	5,396.0	2.4%	573.3	11.9%
Battery	4.6	0.0%	31.0	0.0%	26.4	574.7%
Biofuel	368.8	0.2%	299.3	0.1%	(69.5)	(18.8%)
Total	225,714.4	100.0%	227,611.8	100.0%	1,897.4	0.8%

Table 3-66 shows the share of generation by natural gas, coal, nuclear and other fuel types in the real-time energy market since 2014.

Table 3-66 Share of generation by fuel source: January through March, 2014 through 2026

Jan - Mar	Natural Gas	Coal	Nuclear	Solar	Wind	Other Fuel Type
2014	15.1%	45.3%	34.4%	0.0%	2.3%	2.9%
2015	18.0%	41.4%	35.8%	0.0%	2.3%	2.5%
2016	21.1%	33.4%	39.2%	0.1%	3.0%	3.2%
2017	21.8%	32.9%	38.7%	0.1%	3.3%	3.1%
2018	24.7%	31.5%	36.2%	0.2%	3.6%	3.8%
2019	31.4%	27.5%	34.0%	0.2%	3.4%	3.5%
2020	39.2%	18.2%	34.9%	0.3%	4.0%	3.4%
2021	34.5%	24.9%	32.9%	0.5%	4.1%	3.1%
2022	35.9%	23.7%	32.2%	0.8%	4.5%	3.0%
2023	42.4%	15.1%	33.5%	1.0%	4.9%	3.1%
2024	43.6%	14.6%	32.5%	1.4%	4.7%	3.3%
2025	41.1%	18.2%	30.6%	2.1%	5.0%	3.0%
2026	42.0%	17.6%	30.2%	2.4%	4.7%	3.1%

Fuel Diversity

Figure 3-48 shows the fuel diversity index (FDI_e) for PJM energy generation.[100] The FDI_e is defined as $\mathbf{1-\sum_{i=1}^{N} s_i^2}$, where s_i is the share of fuel type *i*. The minimum possible value for the FDI_e is zero, corresponding to all generation from a single fuel type. The maximum possible value for the FDI_e results when each fuel type has an equal share of total generation. For a generation fleet composed of 10 fuel types, the maximum achievable index is 0.9. The fuel type categories used in the calculation of the FDI_e are the 10 primary fuel sources in Table **3-63** with nonzero generation values. As fuel diversity has increased, seasonality in the FDI_e has decreased and the FDI_e has exhibited less volatility. Since 2012, the monthly FDI_e has been less volatile as a result of the decline in the share of coal from 51.3 percent prior to 2012 to 27.5 percent from 2012 through March 2026. A significant drop in the FDI_e occurred in the fall of 2004 as a result of the expansion of the PJM market footprint into ComEd, AEP, and Dayton Power & Light Zones and the increased shares of coal and nuclear that resulted.[101] The increasing trend that began in 2008 is a

100 The MMU developed the FDI to provide an objective metric of fuel diversity. The FDI metric is similar to the HHI used to measure market concentration. The FDI is calculated separately for energy output and for installed capacity.

101 See the *2019 Annual State of the Market Report for PJM*, Volume 2, Appendix A, "PJM Geography" for an explanation of the expansion of the PJM footprint. The integration of the ComEd Control Area occurred in May 2004 and the integration of the AEP and Dayton Zones occurred in October 2004.

result of decreasing coal generation, increasing gas generation and increasing renewable generation. Coal generation as a share of total generation was 58.1 percent for the first three months of 2008 and 17.6 percent for the first three months of 2026. Gas generation as a share of total generation was 5.5 percent for the first three months of 2008 and 42.1 percent for the first three months of 2026. Wind and solar generation as a share of total generation was 0.5 percent for the first three months of 2008 and 7.1 percent for the first three months of 2026.

The FDI_e decreased 0.6 percent in the first three months of 2026 compared to the first three months of 2025. Increased gas generation and less generation from coal fired and nuclear generators led to the decrease in the FDI_e.

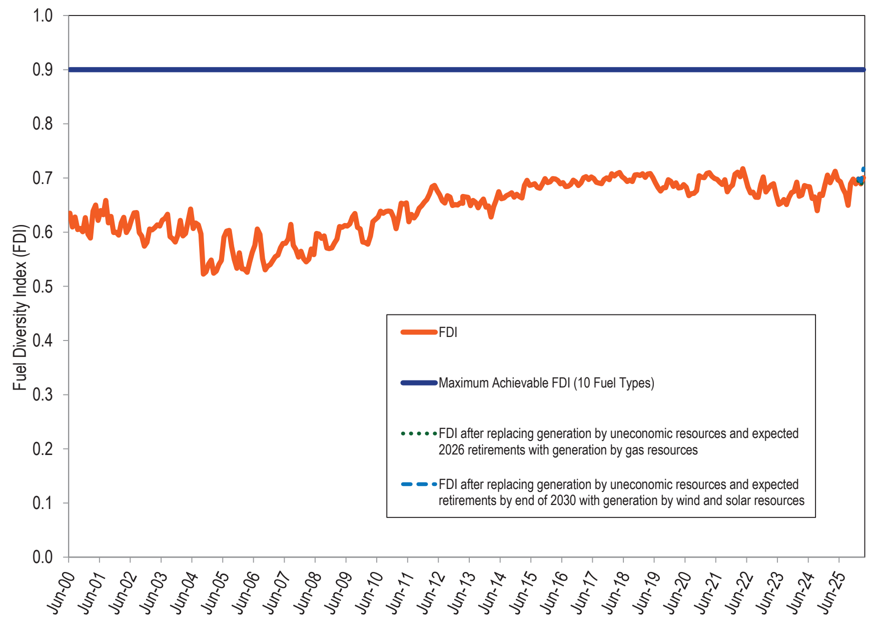
The FDI_e was also used to measure the impact on fuel diversity of potential retirements in 2026 through 2030. A total of 10,963 MW of capacity are at risk of retirement, consisting of 8,330 MW currently planning to retire and 2,633 MW expected to be uneconomic.[102] This capacity consists primarily of coal steam plants and CTs. The units expected to retire by the end of 2026 generated 1,519.4 GWh in the first three months of 2026. The dashed line (green) in Figure 3-48 shows a counterfactual result for FDI_e assuming the 1,519.4 GWh of generation from uneconomic units and expected 2026 retirements were replaced by gas generation.[103] The FDI_e for the first three months of 2026 under this counterfactual assumption would have been 0.4 percent lower than the actual FDI_e. The units expected to retire by the end of 2030 generated 6,145.7 GWh in the first three months of 2026. Replacing this generation with wind and solar generation results in a counterfactual FDI_e that is 1.0 percent higher than the actual FDI_e.[104] The dashed line (blue) in Figure 3-48 shows a counterfactual result for FDI_e assuming that this generation is replaced with gas, wind and solar generation.

102 See Units At Risk of Retirement in the *2025 Annual State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue.

103 It is assumed that all of the replacement energy is from gas units. In previous reports, solar and wind energy have also been used for replacement energy with the amounts based on the expected increase in the PJM RPS obligation for the upcoming year. But the PJM RPS obligation will decrease in 2027 in comparison to 2026 due to the termination of the Ohio RPS in 2027.

104 The split between solar (63.1 percent) and wind (36.9 percent) is based on queue data and 2026 capacity factors in Table 8-33 and Table 8-37. In previous reports, the replacement energy was sourced from gas units in addition to solar and wind units with the amount of solar and gas replacement energy being based on the expected increase in the PJM RPS obligation in 2030 in comparison to current year. But the RPS increase for 2030 exceeds the energy attributable to the expected retirements, and only solar and wind are used for replacement energy in this scenario.

Figure 3-48 Fuel diversity index for monthly generation: June 2000 through March 2026



Natural Gas Supply Issues

Both pipeline transportation and commodity natural gas are needed to deliver natural gas to power plants. Generators have a number of options which vary by pipeline and market area. A generator could purchase a delivered service in which the seller bundles the transportation and commodity, on a term contract or a spot basis. A generator could purchase pipeline transportation and commodity natural gas separately with a term supply contract or through daily purchases in the spot market. Generators could purchase storage service. Storage services can be bundled with pipeline transportation, or storage and transportation purchased separately to move gas to or from a storage facility. The storage service will determine the total storage capacity and the injection and withdrawal rights. Storage offers the owner the ability to have on demand supplies, or the ability to redirect unused supplies to storage. Predetermined allocation (PDA) nominations can be used to direct the pipeline as to how to treat an excess or a deficiency of gas at a delivery point. Combinations of these options are also available.

Pipelines build transportation capacity and sell firm capacity to customers. Most of the transportation capacity is sold at tariff rates but in some cases negotiated rates are agreed to. A majority of firm capacity is contracted with gas utilities, gas marketers, industrial customers and generators. The purchasers of firm transportation capacity have the right to resell their capacity. Any such release must be done on the pipeline's electronic bulletin board. Bidders must be approved by the pipeline. When firm capacity on the pipelines is not being used, the pipeline tariffs provide for interruptible service.

In order to be able to actually use the purchased pipeline transportation service, pipelines may enforce nomination deadlines to require generation owners to nominate the flow of gas by defined deadlines. Some pipelines may also impose site specific restrictions that limit the ability of generators to nominate and schedule gas beyond the nomination deadlines. Table 3-67 shows the approved nomination deadlines and corresponding start time of gas flow.[105] Pipelines provide that firm service requests may replace, or bump, interruptible nominations on the pipeline under defined conditions.

Table 3-67 Approved nomination deadlines

	Nomination Cycle	Nom Deadline (EPT)	Time of Flow (EPT)	Bumping	Hours left in gas day for supply to flow
Day Before Flow	Timely	1400	1000		24
Day Before Flow	Evening	1900	1000	Yes	24
Day of Flow	Intraday 1	1100	1500	Yes	19
Day of Flow	Intraday 2	1530	1900	Yes	15
Day of Flow	Intraday 3	2000	2300	No	11

In the winter period from November 2025 through March 2026 some interstate gas pipelines that provide service in the PJM service territory issued notices limiting the flexibility of firm and nonfirm transportation services. These notices include alerts, constraints, warnings of operational flow orders (OFO) and actual OFOs. These notices generally permit the pipelines to enforce nomination deadlines and to restrict the provision of gas to 24 hour ratable takes, meaning that nominations must be the same for each hour in the gas day. Pipelines may also enforce strict balancing constraints which limit the ability of gas users to deviate from the 24 hour ratable take and which may limit the ability of users to have access to unused gas. The pipelines providing service in the PJM service territory that issued notices were: ANR Pipeline, Columbia Gas Transmission, Cove Point, Eastern Gas Transmission Pipeline System, Eastern Shore Natural Gas Pipeline, East Tennessee Natural Gas, Eastern Gas Transmission & Storage, Horizon Pipeline, Natural Gas Pipeline, Northern Border Pipeline, Texas Eastern, Tennessee Gas Pipeline and Transcontinental Gas Pipeline.

Pipeline operators use restrictive and inflexible rules to manage the balance of supply and demand during constrained operating conditions determined by the pipeline. The independent operations of geographically overlapping pipelines during extreme conditions highlight the shortcomings of a gas pipeline network that relies on individual pipelines to manage the balancing of total supply and demand across a broad geographical area that includes multiple pipelines. The independent operational restrictions imposed by pipelines and the impact on electric generators during extreme conditions demonstrate the potential benefits to creating a separate gas ISO/RTO structure to coordinate the supply of gas across pipelines and with the electric RTOs and to facilitate the interoperability of the pipelines in an explicit network.

The increase in natural gas fired capacity in PJM, and the expected further increase, has highlighted issues with the dependence of PJM system reliability on the fuel transportation arrangements entered into by generators. The risks to the fuel supply for gas generators, including the risk of interruptible supply on cold days and the ability to get gas on short notice during times of critical pipeline operations, create risks for the bulk power system.

In general, the availability status of gas generators in the PJM energy market does not accurately reflect their ability to procure and nominate gas on the pipelines based on the rules defined by the pipelines. If the result of the pipeline rules is that some gas generators cannot reliably procure gas during the operating day in order to respond to PJM directions to generate, the result

105 Nomination deadlines approved in FERC Order No. 809, implemented April 1, 2016.

could be an inflated estimate of reserves on the PJM system, if the generator does not have back up fuel. Gas units should be required to be on forced outage if they cannot obtain gas during the operating day to meet their must offer requirement.

PJM requires real-time situational awareness of the availability of all generators, including gas-fired generators, during the operating day, in order to operate the system effectively including knowledge of the level of available reserves. 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.

Notification time is the period between PJM's notification and the beginning of the start sequence for a generating resource. Combustion turbines normally have notification times between six and 30 minutes. When pipelines require generators to nominate gas per the NAESB deadlines, generators must nominate gas well in advance and cannot start in six or 30 minutes. Instead, generators need significantly more time to nominate gas. This increase in the time needed should be requested and reflected in the units' notification time.

For example, the last nomination cycle available per NAESB is intraday 3 (ID3), see Table 3-67. The ID3 deadline is 20:00 EPT for gas that starts flowing at 23:00 (in three hours). The previous cycle, intraday 2 (ID2) deadline is at 15:30 EPT for gas that starts flowing at 19:00. A generator that has not nominated gas by ID2 cannot start until 23:00. Therefore, at 19:00, the unit has an implied time to start of four hours. Four hours is equal to 23:00 (the earliest the unit can start) minus 19:00. Table 3-68 shows the notification time gas fired generators should be requesting and submitting when pipelines require nominating per the NAESB cycle deadlines.

Table 3-68 Generator notification times when pipeline NAESB cycle deadlines are imposed

Hour	HE1	HE2	HE3	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12
Notification Time	15	14	13	12	11	10	9	8	7	6	9	8
Time On (If Called)	15:00	15:00	15:00	15:00	15:00	15:00	15:00	15:00	15:00	15:00	19:00	19:00
Nearest Cycle	ID1	ID1	ID1	ID1	ID1	ID1	ID1	ID1	ID1	ID1	ID2	ID2

Hour	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
Notification Time	7	6	9	8	7	6	5	20	19	18	17	16
Time On (If Called)	19:00	19:00	23:00	23:00	23:00	23:00	23:00	15:00	15:00	15:00	15:00	15:00
Nearest Cycle	ID2	ID2	ID3	ID3	ID3	ID3	ID3	ID1	ID1	ID1	ID1	ID1

The MMU proposed enhancements for situational awareness and transparency to improve the scheduling problem that PJM and gas fired units face, addressing how to reflect pipeline constraints in generator operating parameters, including how generators should submit notification times, and minimum run times and request temporary parameter exceptions.[106] The resultant guidelines were posted by the MMU and PJM on September 8, 2023.[107]

Types of Marginal Resources

LMPs result from the operation of a market based on security-constrained, least-cost dispatch in which marginal resources determine system LMPs, based on their offers. Marginal resource designation is not limited to physical resources in the day-ahead energy market. INC offers, DEC bids and up to congestion transactions are dispatchable injections and withdrawals in the day-ahead energy market that can set price via their offers and bids.

Table 3-69 shows the type of fuel used and technology by marginal resources in the real-time energy market. There can be more than one marginal resource in any given interval as a result of transmission constraints. In the first three months of 2026, coal units were 9.6 percent and natural gas units were 65.9 percent of marginal resources. In the first three months of 2026, natural gas combined cycle units were 55.5 percent of marginal resources. In the first three months of 2025, coal units were 8.1 percent and natural gas units were

106 "Gas Nomination Cycles and Units Operating Parameters," Electric Gas Coordination Senior Task Force (EGCSTF), August 15, 2023.
107 *See* Guidelines posted by the MMU and PJM: Temporary Operating Parameter Limit (PLS) Exceptions due to Pipeline Restrictions. <http://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Temporary_Operating_Parameter_Limit_(PLS)_Exceptions_due_to_Pipeline_Restrictions_20230908.pdf>.

71.1 percent of the total marginal resources. In the first three months of 2025, natural gas combined cycle units were 62.9 percent of the total marginal resources. In the first three months of 2026, 75.7 percent of the wind marginal units had negative offer prices, 23.2 percent had zero offer prices and 1.1 percent of the wind marginal units had positive offer prices. In the first three months of 2025, 70.8 percent of the wind marginal units had negative offer prices, 28.0 percent had zero offer prices and 1.2 percent had positive offer prices.

The proportion of marginal nuclear units increased from 0.01 percent in the first three months of 2025 to 0.20 percent in the first three months of 2026. Most nuclear units are offered as fixed generation in the PJM market. A small number of nuclear units have been offered with a dispatchable range since 2015. The dispatchable nuclear units do not always respond to dispatch instructions.

PJM implemented fast start pricing on September 1, 2021. The marginal resources shown in Table 3-69 are from the pricing run, which may not be the same as marginal resources from the dispatch run.

Table 3-69 Type of fuel used and technology (By real-time marginal units): January through March, 2022 through 2026[108]

		(Jan - Mar)				
Fuel	Technology	2022	2023	2024	2025	2026
Gas	CC	56.05%	70.50%	64.09%	62.90%	55.51%
Wind	Wind	14.11%	8.00%	17.85%	15.82%	20.23%
Coal	Steam	15.30%	11.65%	8.95%	8.08%	9.61%
Gas	CT	5.96%	6.40%	6.73%	6.49%	8.06%
Oil	CT	5.70%	0.69%	0.14%	1.37%	1.88%
Gas	Steam	0.95%	0.77%	1.03%	0.91%	1.63%
Other	Solar	0.53%	0.00%	0.04%	1.15%	1.58%
Gas	RICE	0.66%	1.39%	0.70%	0.82%	0.75%
Uranium	Steam	0.51%	0.07%	0.17%	0.01%	0.20%
Oil	RICE	0.05%	0.08%	0.09%	1.98%	0.14%
Municipal Waste	Steam	0.03%	0.02%	0.06%	0.06%	0.12%
Oil	Steam	0.00%	0.00%	0.02%	0.05%	0.12%
Municipal Waste	RICE	0.00%	0.01%	0.10%	0.09%	0.06%
Oil	CC	0.08%	0.38%	0.04%	0.18%	0.05%
Other	Steam	0.07%	0.05%	0.03%	0.05%	0.04%
Other	Battery	0.00%	0.00%	0.01%	0.01%	0.03%
Landfill Gas	CT	0.00%	0.00%	0.00%	0.01%	0.00%
Municipal Waste	CT	0.00%	0.00%	0.00%	0.00%	0.00%
Coal	CT	0.00%	0.00%	0.00%	0.00%	0.00%
Gas	Fuel Cell	0.00%	0.00%	0.00%	0.00%	0.00%
Landfill Gas	Steam	0.00%	0.00%	0.00%	0.00%	0.00%
Landfill Gas	RICE	0.00%	0.00%	0.00%	0.00%	0.00%

108 The unit type RICE refers to Reciprocating Internal Combustion Engines.

Figure 3-49 shows the type of fuel used by marginal resources in the real-time energy market for the first three months of every year since 2004. The role of coal as a marginal resource has declined while the role of gas as a marginal resource has increased.

Figure 3-49 Type of fuel used (By real-time marginal units): January through March, 2004 through 2026

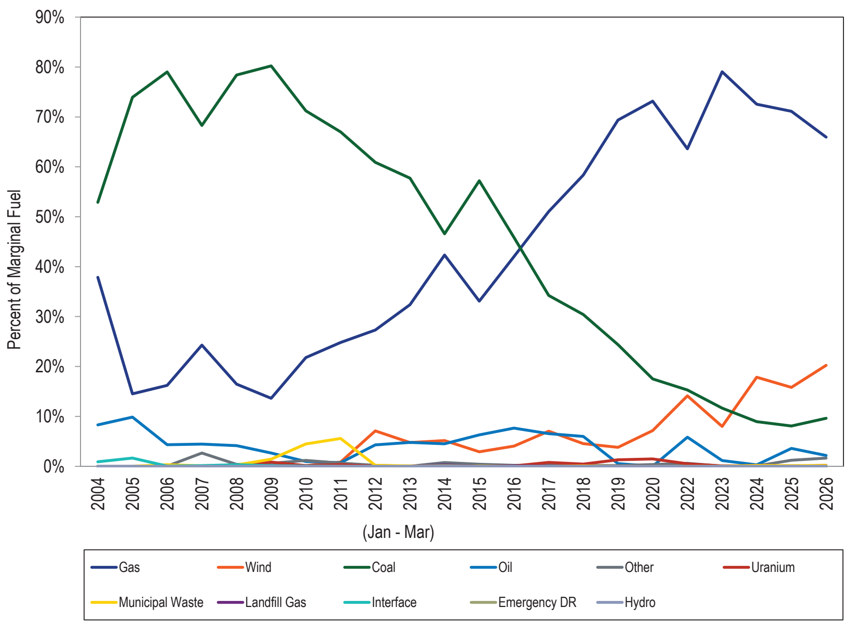


Table 3-70 shows the type of fuel and technology by fast start marginal resources and other marginal resources in the real-time energy market in the first three months of 2026. In the first three months of 2026, marginal fast start resources accounted for 6.2 percent of all marginal resources in the pricing run.

Table 3-70 Fuel type and technology (Real-time marginal units and fast start marginal units): January through March, 2026

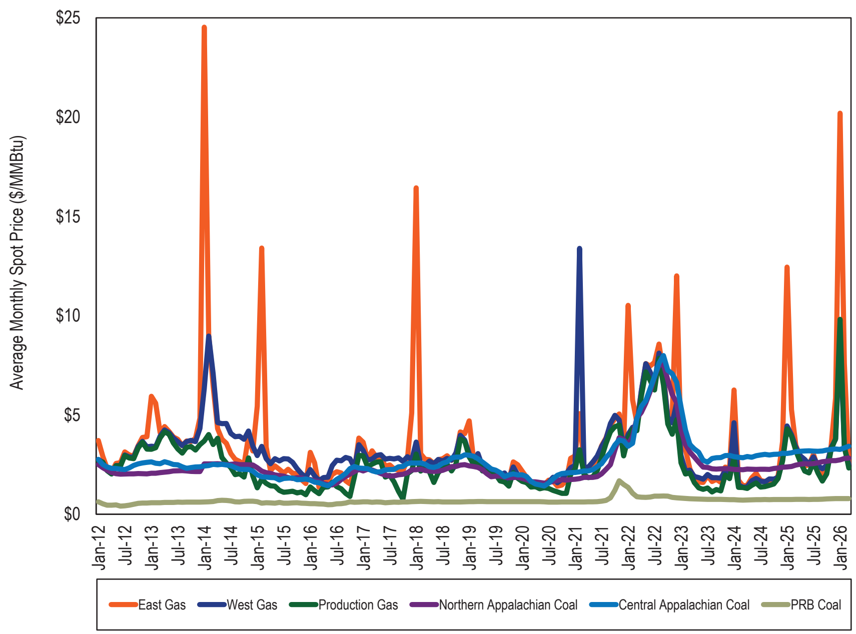
		2026 (Jan - Mar)		
Fuel	Technology	Fast Start	Other	Both
Coal	Steam	0.00%	9.61%	9.61%
Gas	CC	0.00%	55.51%	55.51%
Gas	CT	3.79%	4.26%	8.06%
Gas	RICE	0.73%	0.02%	0.75%
Gas	Steam	0.00%	1.63%	1.63%
Landfill Gas	CT	0.00%	0.00%	0.00%
Municipal Waste	RICE	0.01%	0.05%	0.06%
Municipal Waste	Steam	0.00%	0.12%	0.12%
Oil	CC	0.00%	0.05%	0.05%
Oil	CT	1.16%	0.72%	1.88%
Oil	RICE	0.13%	0.01%	0.14%
Oil	Steam	0.00%	0.12%	0.12%
Other	Battery	0.00%	0.03%	0.03%
Other	Solar	0.05%	1.53%	1.58%
Other	Steam	0.00%	0.04%	0.04%
Uranium	Steam	0.00%	0.20%	0.20%
Wind	Wind	0.36%	19.87%	20.23%
All Marginal Units		6.22%	93.78%	100.00%

Fuel Price Trends and LMP

In a competitive market, changes in LMP follow changes in the marginal costs of marginal units, the units setting LMP. In general, fuel costs make up between 80 percent and 90 percent of short run marginal cost depending on generating technology, unit efficiency, unit age and other factors. The impact of fuel cost on marginal cost and on LMP depends on the fuel burned by marginal units and changes in fuel costs. Changes in emission allowance costs also contribute to changes in the marginal cost of marginal units.

Figure 3-50 shows fuel prices in PJM for 2012 through March 2026. Natural gas prices and coal prices increased and oil prices decreased in the first three months of 2026 compared to the first three months of 2025. In the first three months of 2026, the price of eastern natural gas was 43.3 percent higher and the price of western natural gas was 27.5 percent higher than in the first three months of 2025. The price of Northern Appalachian coal was 15.4 percent higher; the price of Central Appalachian coal was 7.8 percent higher; and the price of Powder River Basin coal was 6.0 percent higher.[109] The price of ULSD NY Harbor Barge (ultra low sulfur diesel) was 22.3 percent higher in the first three months of 2026 than in the first three months of 2025.

Figure 3-50 Spot average fuel price comparison: 2012 through March 2026 ($/MMBtu)



Components of LMP

Components of Real-Time Load-Weighted LMP

LMPs result from the operation of a market based on security-constrained, economic (least cost) dispatch (SCED) in which marginal units determine system LMPs, based on their offers and up to 14 minute ahead forecasts of system conditions. Those offers can be decomposed into components including fuel costs, emission costs, variable operation and maintenance (VOM) costs, markup, FMU adder and the 10 percent cost adder. As a result, it is possible to decompose LMP by the components of unit offers.

Cost offers of marginal units are separated into their component parts. The fuel related component is based on unit specific heat rates and spot fuel prices. Emission costs are calculated using spot prices for NO_x, SO_2 and CO_2 emission credits, emission rates for NO_x, emission rates for SO_2 and emission rates for CO_2. The CO_2 emission costs are applicable to PJM units in the PJM states that participate in RGGI: Delaware, Maryland, and New Jersey.[110] The FMU adder is the calculated contribution of the FMU and AU adders to LMP that results when units with FMU or AU adders are marginal.

Since the implementation of scarcity pricing on October 1, 2012, PJM jointly optimizes the commitment and dispatch of energy and reserves. When generators providing energy have to be dispatched down from their economic operating level to meet reserve requirements, the joint optimization of energy and reserves takes into account the opportunity cost of the reduced generation and the associated incremental cost to maintain reserves. If a unit incurring such opportunity costs is a marginal resource in the energy market, this opportunity cost will contribute to LMP. The component, ancillary service redispatch cost, shows the contribution of this cost to the PJM's load-weighted LMP. In addition, in periods when the pricing run solution does not meet the reserve requirements, PJM invokes shortage pricing, based on the operating reserve demand curve. During shortage conditions, the LMPs of marginal generators reflect the cost of not meeting the reserve requirements, the scarcity component, which is defined by the operating reserve demand curve.[111]

Starting on September 1, 2021, the components shown in Table 3-71 and Table 3-73 are from the pricing run, which includes the impact of amortized start cost and amortized no load cost of the fast start marginal units. The

109 Eastern natural gas consists of the average of Texas M3, Transco Zone 6 non-NY, Transco Zone 6 NY and Transco Zone 5 daily indices. Western natural gas prices are the average of Columbia Appalachia and Chicago Citygate daily indices. Production gas prices are the average of Dominion South Point, Tennessee Zone 4, and Transco Leidy Line receipts daily indices. Coal prices are the average of daily fuel prices for Central Appalachian coal, Northern Appalachian coal, and Powder River Basin coal. All fuel prices are from Platts.

110 New Jersey withdrew from RGGI, effective January 1, 2012, and rejoined RGGI effective January 1, 2020. Virginia joined RGGI effective January 1, 2021, left RGGI on December 31, 2023, and will rejoin RGGI on July 1, 2026. Pennsylvania took action to join RGGI on April 23, 2023. The action was enjoined in the course of litigation. The litigation ended after the legislative basis for Pennsylvania's participation in RGGI was removed on November 12, 2025.

111 Scarcity component includes ancillary service redispatch cost component during periods of scarcity.

components of LMP are shown in Table 3-71, including markup using unadjusted cost-based offers.[112] Table 3-71 shows that in the first three month of 2026, 5.2 percent of the load-weighted LMP was the result of coal costs, 47.0 percent was the result of gas costs and 2.1 percent was the result of the cost of carbon emission allowances. The fuel-related components of LMP reflect the degree to which the cost of the identified fuel affects LMP and does not reflect the other components of the offers of units burning that fuel. Using unadjusted cost-based offers, negative markup was -7.6 percent of the load-weighted LMP. Using unadjusted cost-based offers, positive markup was 8.2 percent of the load-weighted LMP. LMP may, at times, be set by transmission constraint penalty factors. In the first three months of 2026, 15.7 percent of the load-weighted LMP was the result of transmission penalty factors. More than 99 percent of this impact occurred as a result of PJM's reduction to line ratings in SCED. In the first three months of 2026, -0.9 percent of the LMP was due to renewable energy credits, production tax credits and investment tax credits. The percent contribution of transmission penalty factors has increased substantially since PJM allowed penalty factors to affect LMPs starting February 1, 2019. The component NA is the unexplained portion of load-weighted LMP. For several intervals, PJM failed to provide all the data needed to accurately calculate generator sensitivity factors. As a result, the LMP for those intervals cannot be decomposed into component costs. The NA component is the cumulative effect of excluding those five minute intervals. The percent column is the difference (in percentage points) in the proportion of LMP represented by each component in the first three months of 2025 and 2026.

Table 3-71 Components of real-time (Unadjusted) load-weighted average LMP: January through March, 2025 and 2026

	2025 (Jan - Mar)		2026 (Jan - Mar)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
Gas	$29.55	56.6%	$41.16	47.0%	(9.6%)
Transmission Constraint Penalty Factor	$4.03	7.7%	$13.76	15.7%	8.0%
Positive Markup	$2.71	5.2%	$7.19	8.2%	3.0%
Oil	$2.90	5.6%	$5.34	6.1%	0.5%
Ten Percent Adder	$3.54	6.8%	$4.87	5.6%	(1.2%)
Coal	$4.06	7.8%	$4.58	5.2%	(2.5%)
Market-to-Market	$0.79	1.5%	$3.72	4.2%	2.7%
Variable Maintenance	$2.49	4.8%	$3.21	3.7%	(1.1%)
Opportunity Cost Adder	$0.60	1.1%	$2.15	2.5%	1.3%
Ancillary Service Redispatch Cost	$1.29	2.5%	$1.86	2.1%	(0.4%)
CO2 Cost	$1.73	3.3%	$1.83	2.1%	(1.2%)
Variable Operations	$1.19	2.3%	$1.50	1.7%	(0.6%)
Scarcity	$0.10	0.2%	$0.95	1.1%	0.9%
LPA Rounding Difference	$0.67	1.3%	$0.95	1.1%	(0.2%)
Increase Generation Differential	$0.29	0.6%	$0.86	1.0%	0.4%
NA	$0.10	0.2%	$0.77	0.9%	0.7%
Emergency Demand Response	$0.00	0.0%	$0.18	0.2%	0.2%
NOx Cost	$0.00	0.0%	$0.17	0.2%	0.2%
Landfill Gas	$0.09	0.2%	$0.11	0.1%	(0.0%)
Other	$0.01	0.0%	$0.02	0.0%	0.0%
SO2 Cost	$0.00	0.0%	$0.00	0.0%	(0.0%)
LPA-SCED Differential	($0.00)	(0.0%)	($0.00)	(0.0%)	0.0%
PJM Administrative Cap	$0.00	0.0%	($0.03)	(0.0%)	(0.0%)
Decrease Generation Differential	($0.02)	(0.0%)	($0.13)	(0.1%)	(0.1%)
Renewable Energy Credits	($0.26)	(0.5%)	($0.83)	(0.9%)	(0.5%)
Negative Markup	($3.66)	(7.0%)	($6.64)	(7.6%)	(0.6%)
Total	$52.20	100.0%	$87.57	100.0%	0.0%

112 These components are explained in the *Technical Reference for PJM Markets*, at p 27 "Calculation and Use of Generator Sensitivity/Unit Participation Factors," <http://www. monitoringanalytics.com/reports/Technical_References/references.shtml>.

Components of Change in LMP

Table 3-72 shows the components of the increase in real-time load-weighted average LMP from the first three months of 2025 to the first three months of 2026. In the first three months of 2026, the real-time load-weighted average LMP increased by $35.37 per MWh, 67.8 percent. Fuel and consumables cost components of LMP (the sum of gas, coal, oil, landfill gas, variable operations) increased the LMP by $14.92 per MWh, 42.2 percent of increase in LMP. The emissions cost components of LMP (the sum of NO_X, CO_2, opportunity cost adder, SO_2, and renewable energy credits) increased the LMP by $1.26 per MWh, 3.6 percent of the increase in LMP. The sum of the positive and negative markups, ten percent adder, and maintenance cost components, all of which reflect market power, increased the LMP $3.56 per MWh, 10.1 percent of the increase in LMP. The scarcity component increased the LMP by $0.85 per MWh, 2.4 percent of the increase in the LMP. The transmission constraint penalty factor increased the LMP by $9.73 per MWh, 27.5 percent, primarily as a result of PJM's reduction of line ratings in SCED. The ancillary service redispatch cost, the opportunity cost of reduced marginal generation to meet reserve requirements, increased the LMP by $0.57 per MWh, 1.6 percent. The pre-emergency demand response called on by PJM during the Winter Storm Fern increased the LMP by $0.18 per MWh, 0.5 percent of the increase in LMP. The LMP increase would have been higher if PJM had not imposed a $3,700.00 per MWh administrative cap. The administrative cap reduced the LMP by $0.03 per MWh, a 0.1 percent decrease.

Table 3-72 Components of change in real-time load-weighted average LMP: January through March, 2025 and 2026

Component	2025 (Jan - Mar)	2026 (Jan - Mar)	Change in LMP	Percent of Total Change
Fuel and Consumables	$37.78	$52.70	$14.92	42.2%
Emission Related	$2.07	$3.32	$1.26	3.6%
Market Power Related	$5.08	$8.63	$3.56	10.1%
Scarcity	$0.10	$0.95	$0.85	2.4%
Transmission Constraint Penalty Factor	$4.03	$13.76	$9.73	27.5%
Ancillary Service Redispatch Cost	$1.29	$1.86	$0.57	1.6%
Pre-emergency Demand Response	$0.00	$0.18	$0.18	0.5%
PJM Administrative Cap	$0.00	($0.03)	($0.03)	(0.1%)
All Other	$1.85	$6.19	$4.34	12.3%
Total Change	$52.20	$87.57	$35.37	100.0%

In order to understand the markup behavior of market participants, real-time and day-ahead LMPs are decomposed using two different approaches. In the first approach (Table 3-71) markup is the difference between the price offer and the cost-based offer (unadjusted markup). In the second approach (Table 3-73), the 10 percent markup is removed from the cost-based offers of coal, gas, and oil units (adjusted markup).

Table 3-73 Components of real-time (Adjusted) load-weighted average LMP: January through March, 2025 and 2026

	2025 (Jan - Mar)		2026 (Jan - Mar)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
Gas	$29.55	56.6%	$41.16	47.0%	(9.6%)
Transmission Constraint Penalty Factor	$4.03	7.7%	$13.76	15.7%	8.0%
Positive Markup	$4.85	9.3%	$10.09	11.5%	2.2%
Oil	$2.90	5.6%	$5.34	6.1%	0.5%
Coal	$4.06	7.8%	$4.58	5.2%	(2.5%)
Market-to-Market	$0.79	1.5%	$3.72	4.2%	2.7%
Variable Maintenance	$2.49	4.8%	$3.21	3.7%	(1.1%)
Opportunity Cost Adder	$0.60	1.1%	$2.15	2.5%	1.3%
Ancillary Service Redispatch Cost	$1.29	2.5%	$1.86	2.1%	(0.4%)
CO2 Cost	$1.73	3.3%	$1.83	2.1%	(1.2%)
Variable Operations	$1.19	2.3%	$1.50	1.7%	(0.6%)
Scarcity	$0.10	0.2%	$0.95	1.1%	0.9%
LPA Rounding Difference	$0.67	1.3%	$0.95	1.1%	(0.2%)
Increase Generation Differential	$0.29	0.6%	$0.86	1.0%	0.4%
NA	$0.10	0.2%	$0.77	0.9%	0.7%
Emergency Demand Response	$0.00	0.0%	$0.18	0.2%	0.2%
NOx Cost	$0.00	0.0%	$0.17	0.2%	0.2%
Landfill Gas	$0.09	0.2%	$0.11	0.1%	(0.0%)
Other	$0.01	0.0%	$0.02	0.0%	0.0%
Ten Percent Adder	$0.01	0.0%	$0.01	0.0%	(0.0%)
SO2 Cost	$0.00	0.0%	$0.00	0.0%	(0.0%)
LPA-SCED Differential	($0.00)	(0.0%)	($0.00)	(0.0%)	0.0%
PJM Administrative Cap	$0.00	0.0%	($0.03)	(0.0%)	(0.0%)
Decrease Generation Differential	($0.02)	(0.0%)	($0.13)	(0.1%)	(0.1%)
Renewable Energy Credits	($0.26)	(0.5%)	($0.83)	(0.9%)	(0.5%)
Negative Markup	($2.27)	(4.3%)	($4.67)	(5.3%)	(1.0%)
Total	$52.20	100.0%	$87.57	100.0%	0.0%

The components of LMP for the dispatch run and the pricing run are shown in Table 3-74, including markup using unadjusted cost-based offers for in the first three months of 2026. The oil cost component is the component with the largest change in the share of total LMP from the dispatch run to the pricing run is, constituting 3.8 percent of the dispatch run LMP and 6.1 percent of the pricing run LMP.

Table 3-74 Comparison of components of real-time (Unadjusted) load-weighted average LMP in the dispatch run and pricing run: January through March, 2026

	Dispatch		Pricing		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
Gas	$39.84	49.1%	$41.16	47.0%	(2.1%)
Transmission Constraint Penalty Factor	$15.15	18.7%	$13.76	15.7%	(3.0%)
Positive Markup	$6.16	7.6%	$7.19	8.2%	0.6%
Oil	$3.11	3.8%	$5.34	6.1%	2.3%
Ten Percent Adder	$4.53	5.6%	$4.87	5.6%	(0.0%)
Coal	$4.90	6.0%	$4.58	5.2%	(0.8%)
Market-to-Market	$3.66	4.5%	$3.72	4.2%	(0.3%)
Variable Maintenance	$2.25	2.8%	$3.21	3.7%	0.9%
Opportunity Cost Adder	$1.64	2.0%	$2.15	2.5%	0.4%
Ancillary Service Redispatch Cost	$0.97	1.2%	$1.86	2.1%	0.9%
CO2 Cost	$1.84	2.3%	$1.83	2.1%	(0.2%)
Variable Operations	$1.43	1.8%	$1.50	1.7%	(0.0%)
Scarcity	$1.30	1.6%	$0.95	1.1%	(0.5%)
LPA Rounding Difference	$0.69	0.8%	$0.95	1.1%	0.2%
Increase Generation Differential	$1.10	1.4%	$0.86	1.0%	(0.4%)
NA	$0.34	0.4%	$0.77	0.9%	0.5%
Emergency Demand Response	$0.18	0.2%	$0.18	0.2%	(0.0%)
NOx Cost	$0.15	0.2%	$0.17	0.2%	0.0%
Landfill Gas	$0.12	0.1%	$0.11	0.1%	(0.0%)
Other	$0.01	0.0%	$0.02	0.0%	0.0%
SO2 Cost	$0.00	0.0%	$0.00	0.0%	(0.0%)
LPA-SCED Differential	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
PJM Administrative Cap	$0.00	0.0%	($0.03)	(0.0%)	(0.0%)
Decrease Generation Differential	($0.13)	(0.2%)	($0.13)	(0.1%)	0.0%
Renewable Energy Credits	($1.03)	(1.3%)	($0.83)	(0.9%)	0.3%
Negative Markup	($7.11)	(8.8%)	($6.64)	(7.6%)	1.2%
Total	$81.08	100.0%	$87.57	100.0%	0.0%

The components of the total cost to real-time load ($M) are shown in Table 3-75, including markup using unadjusted cost-based offers. The components of the total cost to real-time load are shown in Table 3-76, including markup using adjusted cost-based offers. In the first three months of 2026, the cost of real-time load increased by $7,872.7 million or 72.9 percent. Of the $18,668.7 million in the total cost of real-time load in the first three months of 2026, $8,775.9 million is due to the cost of gas, $2,933.4 million is due to the transmission penalty factor, $1,533.7 million is due to the positive markup, $976.9 million is due to the cost of coal, $683.5 million is due to the variable maintenance and $1,038.3 million is due to the ten percent adder.

Table 3-75 Components of the cost of real-time (Unadjusted) load: January through March, 2025 and 2026

	Contribution to Real Time Cost of Load ($Million)			
Element	2025 (Jan - Mar)	2026 (Jan - Mar)	Change	Percent
Gas	$6,111.6	$8,775.9	$2,664.3	33.8%
Transmission Constraint Penalty Factor	$833.8	$2,933.4	$2,099.6	26.7%
Positive Markup	$560.9	$1,533.7	$972.8	12.4%
Oil	$599.8	$1,138.8	$539.0	6.8%
Ten Percent Adder	$731.7	$1,038.3	$306.6	3.9%
Coal	$839.8	$976.9	$137.1	1.7%
Market-to-Market	$164.4	$792.6	$628.2	8.0%
Variable Maintenance	$514.3	$683.5	$169.2	2.1%
Opportunity Cost Adder	$123.1	$458.5	$335.3	4.3%
Ancillary Service Redispatch Cost	$267.5	$396.7	$129.3	1.6%
CO2 Cost	$357.0	$391.1	$34.1	0.4%
Variable Operations	$245.2	$320.7	$75.5	1.0%
Scarcity	$20.0	$202.3	$182.2	2.3%
LPA Rounding Difference	$138.3	$202.0	$63.8	0.8%
Increase Generation Differential	$60.6	$183.8	$123.3	1.6%
NA	$21.3	$164.2	$143.0	1.8%
Emergency Demand Response	$0.0	$38.5	$38.5	0.5%
NOx Cost	$0.1	$35.7	$35.5	0.5%
Landfill Gas	$18.0	$23.3	$5.3	0.1%
Other	$2.1	$5.0	$2.9	0.0%
SO2 Cost	$0.1	$0.1	($0.0)	(0.0%)
LPA-SCED Differential	($0.0)	($0.0)	$0.0	0.0%
PJM Administrative Cap	$0.0	($6.8)	($6.8)	(0.1%)
Decrease Generation Differential	($3.6)	($27.2)	($23.6)	(0.3%)
Renewable Energy Credits	($52.9)	($177.0)	($124.1)	(1.6%)
Negative Markup	($756.8)	($1,415.1)	($658.3)	(8.4%)
Total	$10,796.1	$18,668.7	$7,872.7	100.0%

Table 3-76 Components of the (Adjusted) cost of real-time load: January through March, 2025 and 2026

	Contribution to Real Time Cost of Load ($Million)			
Element	2025 (Jan - Mar)	2026 (Jan - Mar)	Change	Percent
Gas	$6,111.6	$8,775.9	$2,664.3	(505.7%)
Transmission Constraint Penalty Factor	$833.8	$2,933.4	$2,099.6	(398.5%)
Positive Markup	$1,002.8	$2,150.2	$1,147.4	(217.8%)
Oil	$599.8	$1,138.8	$539.0	(102.3%)
Coal	$839.8	$976.9	$137.1	(26.0%)
Market-to-Market	$164.4	$792.6	$628.2	(119.2%)
Variable Maintenance	$514.3	$683.5	$169.2	(32.1%)
Opportunity Cost Adder	$123.1	$458.5	$335.3	(63.6%)
Ancillary Service Redispatch Cost	$267.5	$396.7	$129.3	(24.5%)
CO2 Cost	$357.0	$391.1	$34.1	(6.5%)
Variable Operations	$245.2	$320.7	$75.5	(14.3%)
Scarcity	$20.0	$202.3	$182.2	(34.6%)
LPA Rounding Difference	$138.3	$202.0	$63.8	(12.1%)
Increase Generation Differential	$60.6	$183.8	$123.3	(23.4%)
NA	$21.1	$164.2	$143.1	(27.2%)
Emergency Demand Response	$0.0	$38.5	$38.5	(7.3%)
NOx Cost	$0.1	$35.7	$35.5	(6.7%)
Landfill Gas	$18.0	$23.3	$5.3	(1.0%)
Other	$2.1	$5.0	$2.9	(0.5%)
Ten Percent Adder	$2.4	$2.8	$0.5	(0.1%)
SO2 Cost	$0.1	$0.1	($0.0)	0.0%
LPA-SCED Differential	($0.0)	($0.0)	$0.0	(0.0%)
PJM Administrative Cap	$0.0	($6.8)	($6.8)	1.3%
Decrease Generation Differential	($3.6)	($27.2)	($23.6)	4.5%
Renewable Energy Credits	($52.9)	($177.0)	($124.1)	23.6%
Negative Markup	($469.2)	($996.1)	($526.9)	100.0%
Total	$10,796.1	$18,668.7	$7,872.7	(1,494.2%)

Table 3-77 shows the components of the increase in the cost of real-time load from the first three months of 2025 to the first three months of 2026. In the first three months of 2026, the cost of real-time load increased $7,872.7 million. Fuel and consumables cost components of LMP (the sum of gas, coal, oil, landfill gas, variable operations) increased the cost of real-time load by $3,421.2 million, 43.5 percent of the increase in the cost of real-time load. The emissions cost components (the sum of NO_X, CO_2, opportunity cost adder, SO_2, and renewable energy credits) increased the real-time cost of load by $280.8 million, 3.6 percent of the increase in the cost of real-time load. The sum of the positive and negative markups, ten percent adder, and maintenance cost components, all of which reflect market power, increased the cost of real-time load by $790.3 million, 10.0 percent of the increase in the cost of real time load. The scarcity component increased the cost of real-time load by $182.2 million, 2.3 percent of the increase in the cost of real-time load. The transmission constraint penalty factor increased the cost of real-time load by $2,099.6 million, 26.7 percent. The ancillary service redispatch cost, the opportunity cost of reduced marginal generation to meet reserve requirements, increased the cost of real-time load by $129.3, 1.6 percent of the cost of real time load. The pre-emergency demand response called on by PJM during the Winter Storm Fern increased the cost of real time load by $38.5 million, 0.5 percent of the increase in the cost of real time load. The cost of real time load would have been higher if PJM had not imposed a $3,700.00 per MWh administrative cap on SMP. The administrative cap reduced the cost of real time load by $6.8 million, a 0.1 percent decrease.

Table 3-77 Components of Change in the cost of real-time load: January through March, 2025 and 2026

	($ Million)			
Component	2025 (Jan - Mar)	2026 (Jan - Mar)	Change	Percent of Total Change
Fuel and Consumables	$7,814.3	$11,235.5	$3,421.2	43.5%
Emission Related	$427.4	$708.2	$280.8	3.6%
Market Power Related	$1,050.1	$1,840.4	$790.3	10.0%
Scarcity	$20.0	$202.3	$182.2	2.3%
Transmission Constraint Penalty Factor	$833.8	$2,933.4	$2,099.6	26.7%
Ancillary Service Redispatch Cost	$267.5	$396.7	$129.3	1.6%
Pre-emergency Demand Response	$0.0	$38.5	$38.5	0.5%
PJM Administrative Cap	$0.0	($6.8)	($6.8)	(0.1%)
All Other	$383.0	$1,320.4	$937.4	11.9%
Total Change	$10,796.1	$18,668.7	$7,872.7	100.0%

Components of Day-Ahead Load-Weighted LMP

LMPs result from the operation of a market based on security-constrained, least-cost dispatch in which marginal resources determine system LMPs, based on their offers. For physical units, those offers can be decomposed into their components including fuel costs, emission costs, variable operation and maintenance costs, markup, and the 10 percent cost offer adder. INC offers, DEC bids and up to congestion transactions are dispatchable injections and withdrawals in the day-ahead energy market with an offer price that cannot be decomposed. Using identified marginal resource offers and the components of unit offers, it is possible to decompose PJM system LMP using the components of unit offers and sensitivity factors.

Table 3-78 shows the components of the PJM day-ahead annual load-weighted average LMP. In the first three months of 2026, 25.2 percent of the load-weighted LMP was the result of gas costs, 6.0 percent of the load-weighted LMP was the result of coal costs, 13.7 percent was the result of INCs, 25.4 percent was the result of DECs, 3.2 percent was the result of UTCs, and 3.9 percent was the result of positive markup.[113] [114]

Table 3-78 Components of day-ahead (Unadjusted) load-weighted average LMP (Dollars per MWh): January through March, 2026

	2026 (Jan - Mar)	
Element	Contribution to LMP	Percent
DEC	$24.18	25.4%
Gas	$24.04	25.2%
INC	$13.08	13.7%
NA	$8.52	8.9%
Coal	$5.68	6.0%
Transmission Constraint Penalty Factor	$5.21	5.5%
Positive Markup	$3.75	3.9%
Up to Congestion	$3.01	3.2%
Ten Percent Adder	$2.87	3.0%
Oil	$1.64	1.7%
Ancillary Service Redispatch Cost	$1.43	1.5%
CO2 Cost	$1.18	1.2%
Variable Operations	$1.13	1.2%
Variable Maintenance	$1.13	1.2%
Increase Generation Differential	$0.96	1.0%
NOx Cost	$0.15	0.2%
Opportunity Cost Adder	$0.14	0.1%
SO2 Cost	$0.00	0.0%
Decrease Generation Differential	($0.00)	(0.0%)
Renewable Energy Credits	($0.42)	(0.4%)
Negative Markup	($2.37)	(2.5%)
Total	$95.30	100.0%

113 MMU identified an error in the marginal resource identification algorithm within the day ahead clearing optimization. The calculation of generator sensitivity factors requires accurate identification of marginal resources. The error was fixed by the PJM software vendor in March 2025. MMU was unable to calculate the component breakdown for 2024 and the first quarter of 2025 due to the inaccurate identification of marginal resources.

114 MMU identified missing and erroneous distribution factors and shadow prices, primarily within the pricing run. The calculation of generator sensitivity factors requires accurate distribution factors and shadow prices. Where available, MMU used distribution factors from the dispatch run. MMU also calculated missing shadow prices for the relevant transmission constraints when feasible. This approach reduced the impact of the errors. Any remaining errors contributed to the NA component.

Table 3-79 shows the components of the PJM day-ahead annual load-weighted average LMP including the adjusted markup calculated by excluding the 10 percent adder from the coal, gas and oil units.[115]

Table 3-79 Components of day-ahead (Adjusted) load-weighted average LMP (Dollars per MWh): January through March, 2026

	2026 (Jan - Mar)	
Element	Contribution to LMP	Percent
DEC	$24.18	25.4%
Gas	$24.04	25.2%
INC	$13.08	13.7%
NA	$8.52	8.9%
Coal	$5.68	6.0%
Positive Markup	$5.47	5.7%
Transmission Constraint Penalty Factor	$5.21	5.5%
Up to Congestion	$3.01	3.2%
Oil	$1.64	1.7%
Ancillary Service Redispatch Cost	$1.43	1.5%
CO2 Cost	$1.18	1.2%
Variable Operations	$1.13	1.2%
Variable Maintenance	$1.13	1.2%
Increase Generation Differential	$0.96	1.0%
NOx Cost	$0.15	0.2%
Opportunity Cost Adder	$0.14	0.1%
SO2 Cost	$0.00	0.0%
Decrease Generation Differential	($0.00)	(0.0%)
Renewable Energy Credits	($0.42)	(0.4%)
Negative Markup	($1.23)	(1.3%)
Total	$95.30	100.0%

Shortage

PJM's real-time energy market experienced five-minute shortage pricing for one or more reserve products for 86 unique five-minute intervals across 17 days in the first three months of 2026. PJM implemented fast start pricing on September 1, 2021, creating the possibility that the pricing run and the dispatch run could classify different intervals as short. In the first three months of 2026, in the pricing run, there were 86 unique five-minute intervals with real-time shortage pricing for one or more reserve products. In the first three months of 2026, in the dispatch run, there were 80 unique intervals with real-time shortage pricing for one or more reserve products.

115 Id.

Emergency Procedures

PJM can give members advanced notice of possible emergency actions that can occur during an operating day. These notifications are classified by urgency. Advisories are usually issued several days in advance. Alerts are declared at least a day in advance. Warnings are issued on the same operating day, usually for an expected emergency action.

Some emergency actions serve as triggers for performance assessment intervals (PAIs) when declared for the RTO or the active subzone. Some emergency actions trigger PAIs unconditionally while others only trigger PAIs when there is a primary reserve shortage for that area.[116] [117] The declaration of such emergency actions for smaller areas, such as for specific control zones, does not trigger a PAI. When communicating emergency procedures, PJM will also post NERC energy emergency alert (EEA) levels.[118] Table 3-80 provides a description of PJM declared emergency procedures, in alphabetical order, including whether they are a trigger for PAIs and the NERC EEA level triggered with the procedure, if any. [119] [120] [121] [122]

NERC energy emergency alerts (EEAs) are declared by reliability coordinators, such as PJM, on their own initiative or by request from a NERC regional entity, such as ReliabilityFirst. NERC Attachment 1-EOP-011-4 defines three EEA levels, each having associated circumstances and responsibilities.[123] PJM is a reliability coordinator, a balancing authority and a transmission operator.

Under NERC EEA 1 ("EEA1"), all available generation resources are being used. Under this alert, "all available generation resources are committed to meet firm load, firm transactions, and reserve commitments", the balancing authority is "concerned" about maintaining contingency reserves, and non-

116 See PJM. "PJM Manual 18: PJM Capacity Market," § 8.4A Non-Performance Assessment, Rev. 62 (Dec. 17, 2025).
117 OATT, Part I (Common Service Provisions) § 1.
118 NERC Attachment 1-EOP-011-4. "Energy Emergency Alerts," February 15, 2024. <https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-011-4.pdf>.
119 See PJM. "PJM Manual 13: Emergency Operations," § 3.3 Cold Weather Advisory / Alert, Rev. 97 (Nov. 20, 202).
120 See PJM. "PJM Manual 13: Emergency Operations," § 3.4 Hot Weather Alert, Rev. 97 (Nov. 20, 2025).
121 See PJM. "PJM Manual 13: Emergency Operations,"§ 2.3.1 Advanced Notice Emergency Procedures: Alerts, Rev. 97 (Nov. 20, 2025).
122 See PJM. "PJM Manual 13: Emergency Operations," § 2.3.2 Real-Time Emergency Procedures (Warnings and Actions), Rev. 97 (Nov. 20, 2025).
123 NERC Attachment 1-EOP-011-4. "Energy Emergency Alerts," February 15, 2024. <https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-011-4.pdf>.

firm wholesale energy sales are curtailed. PJM declares an EEA1 when entering into capacity emergencies.[124] For example, PJM declares an EEA1 in the process of issuing a maximum generation emergency/load management alert.

Under NERC EEA 2 ("EEA2"), the balancing authority has activated load management procedures and is no longer able to meet its expected energy requirements, but is still able to meet its contingency reserve requirement. Under an EEA2, PJM must communicate and coordinate with other reliability coordinators. PJM must work with transmission owners to see whether equipment can be returned to service. For example, PJM declares an EEA2 in the process of issuing an emergency load management reduction action.

Under NERC EEA 3 ("EEA3"), the balancing authority is unable to meet its contingency reserve requirement and load is actively being dumped or will soon be dumped. An EEA3 can only be declared after all available generation is online and demand-side response resources are called. During an EEA3, PJM must continue steps begun in an EEA2. For example, PJM declares an EEA3 in the process of issuing a manual load dump warning and, when PJM is not able to meet its contingency reserve requirement, in the process of issuing a voltage reduction action.

124 See PJM. "PJM Manual 13: Emergency Operations,"§ 2.3.2 Real-Time Emergency Procedures (Warnings and Actions), Rev. 97 (Nov. 20, 2025).

Table 3-80 Description of emergency procedures

Emergency Procedure	Priority Level	Triggers NERC Energy Emergency Alert	Triggers Performance Assessment Interval	Purpose
Cold Weather Advisory	Advisory			To notify personnel and facilities that PJM may issue a Cold Weather Alert.
Cold Weather Alert	Alert			To prepare personnel and facilities for extreme cold weather conditions, generally when forecast weather conditions approach minimum or temperatures fall below ten degrees Fahrenheit.
Conservative Operations	Alert			To notify personnel and facilities that PJM may operate more conservatively. This can be due to natural phenomena, weather events, security events, and other conditions. Conservative operations may result in the use of larger contingencies and stricter transfer limits.
Emergency Mandatory Load Management Reduction Action	Action	EEA2		To request load reductions from customers registered in the PJM Demand Response program that need 30, 60, or 120 minute lead time to provide additional load relief, generally declared simultaneously with NERC Energy Emergency Alert Level 2 (EEA2)
Geomagnetic Disturbance Action	Action			To inform members that PJM will operate the grid with more conservative transfer limits developed for such disturbances. Transmission owners must coordinate with PJM before acting upon their own disturbance procedures.
Geomagnetic Disturbance Warning	Warning			To warn members that the National Oceanic and Atmospheric Administration predict a possible geomagnetic storm of severity K7 or greater, which can induce currents in the system and equipment.
High System Voltage Action	Action			To prepare the system for possible high voltages and to coordinate with transmission owners and generation owners for managing those high voltages.
Hot Weather Alert	Alert			To prepare personnel and facilities for extreme hot and/or humid weather conditions, generally when forecast temperatures exceed 90 degrees with high humidity.
Low Voltage Alert	Alert			To alert transmission owners and generation owners that a period of low voltage and high load are expected.
Maintenance Outage Recall	Informational			To request that generation owners make units available by canceling any maintenance outages within at least 72 hours of posting. After that time, maintenance outages are converted into forced outages.
Maximum Emergency Action	Action		Yes with PR shortage	To provide real time notice to increase generation above the maximum economic level. It is implemented whenever generation is needed that is greater than the maximum economic level.
Maximum Emergency Generation Alert	Alert	EEA1		To provide an early alert at least one day prior to the operating day that system conditions may require the use of the PJM emergency procedures and resources must be able to increase generation above the maximum economic level of their offers.
Non-Market Post Contingency Local Load Relief Warning	Warning			To warn transmission owners of the possibility of load shed in their area for non-market facilities.
Post Contingency Local Load Relief Warning	Warning			To warn transmission owners of the possibility of load shed in their area.
Pre-Emergency Mandatory Load Management Reduction Action	Action			To request load reductions from customers registered in the PJM Demand Response program that need 30, 60, or 120 minute lead time before declaring emergency load management reductions
Transmission Loading Relief (TLR)	Informational			To maintain transmission operating security limits. This can involve curtailing external transactions and charging outside customers for the cost of congestion.
Unit Startup Notification Alert	Alert			To direct generation owners to prepare units so that long lead time units can come online within 48 hours. This notice is given days in advance of the predicted need.

Not all emergency procedures defined in Table 3-80 are included in Table 3-81, Table 3-82, Figure 3-51, Figure 3-52 and Figure 3-53, even if they occurred in the first three months of 2026. Synchronized reserve events are covered in more detail in Section 10. Information about frequent events are treated separately. Post Contingency Local Load Relief Warnings (PCLLRWs) and Non-Market Post Contingency Local Load Relief Warnings (NMPCLLRWs) are shown in Figure 3-56 and Figure 3-57. Transmission loading relief informational postings (TLRs) are discussed in the Interchange Transactions section of this report.[125] Local load relief warnings provide transmission owners advanced warning of possible local load shed in an area in order to relieve a local constraint and are separate

125 See *2025 Annual State of the Market Report for PJM,* Vol. 2, Section 9: Interchange Transactions.

from manual load dump warnings. Transmission loading relief is a NERC procedure for curtailing interchange transactions to avoid violating operational limits of the system.[126] [127]

Table 3-81 shows the dates affected by emergency alerts, warnings, actions, and informational postings in the first three months of 2026. Events in Table 3-81 can span multiple days, but only the first day is shown. Advisories, alerts, warnings, and informational postings do not necessarily take effect immediately. For example, for cold weather alerts, the dates affected are when PJM expects the cold weather requiring the alert to occur. For maintenance outage recalls, the dates affected are from the date PJM initiates the recall until the date the units are expected to be available. Figure 3-51 shows the timeline of the advisories, alerts, warnings, actions, and the maintenance outage recall during the cold weather event in late January and early February, which included Winter Storm Fern.

Table 3-81 Starting days of declared emergency alerts, warnings actions, and certain informational postings: January through March, 2026

Date	Cold Weather Alert	Hot Weather Alert	Conservative Operations	Pre-Emergency Mandatory Load Management Reduction	Emergency Mandatory Load Management Reduction	Geomagnetic Disturbance Warning	Geomagnetic Disturbance Action	Low Voltage Alert	High System Voltage Action	Unit Startup Notification Alert	Maintenance Outage Recall	Maximum Emergency Generation Alert	Maximum Emergency Generation Action
19-Jan-2026	Western					PJM RTO							
20-Jan-2026	PJM RTO					PJM RTO							
21-Jan-2026						PJM RTO					PJM RTO		
23-Jan-2026	Western												
24-Jan-2026	PJM RTO		PJM RTO										
25-Jan-2026				Southern, BGE, PEPCO									
27-Jan-2026								PJM RTO				PJM RTO	
07-Feb-2026	PJM RTO												

126 NERC IRO-006-5. "Reliability Coordination — Transmission Loading Relief (TLR)," November 4, 2010. <https://www.nerc.com/pa/Stand/Reliability%20Standards/IRO-006-5.pdf>.
127 NERC IRO-006-EAST-2. "Transmission Loading Relief Procedure for the Eastern Interconnection," August 13, 2015. <https://www.nerc.com/pa/Stand/Reliability%20Standards/IRO-006-EAST-2.pdf>.

Figure 3-51 Days with applicable alerts, actions, and recalls[128]: January 17 through February 4, 2026

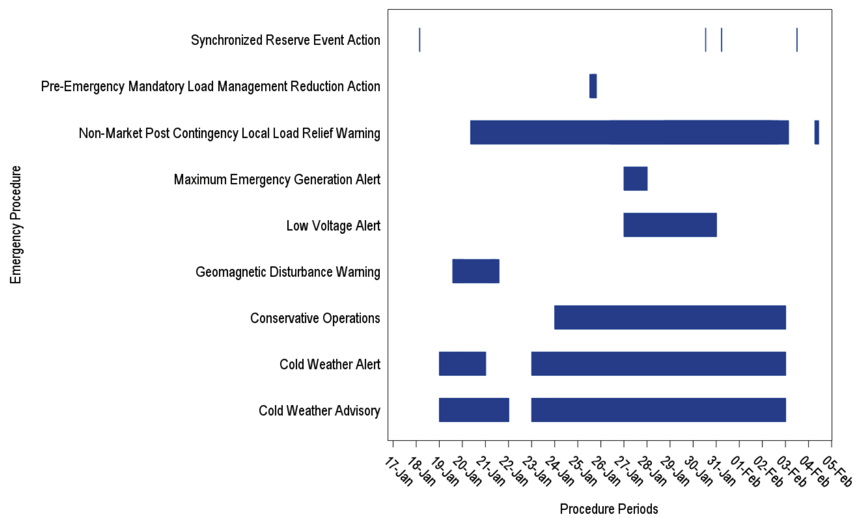


Table 3-82 shows the number of days for which emergency alerts, warnings, actions, and informational postings were declared by PJM in the first three months of 2025 and the first three months of 2026. In the first three months of 2026, there were zero days with emergency actions and shortages that triggered Performance Assessment Intervals (PAIs).[129]

Table 3-82 Number of days for which PJM declared events (alerts, warnings, actions, and certain informational postings)[130 131]: January through March, 2025 and 2026

	Number of days for which events declared	
Event Type	2025 (Jan-Mar)	2026 (Jan-Mar)
Cold Weather Alert	13	16
Conservative Operations	8	10
Geomagnetic Disturbance Warning	2	3
High System Voltage Action	1	0
Low Voltage Alert	5	4
Maintenance Outage Recall	5	0
Maximum Emergency Generation Alert	1	1
Pre-Emergency Mandatory Load Management Reduction Action	1	1
Shortage Pricing	6	17
Energy export recalls from PJM capacity resources	0	0

128 To be consistent with other statistics in this section, the length of the maintenance outage recall has been reduced to the days starting from when the recall was issued until the time units were expected to be available. In the previous report, the recall was shown as lasting until near the end of the cold weather.

129 A PAI is triggered when PJM takes an emergency action and there is a shortage of primary reserves. See 184 FERC ¶ 61,058 (2023).
130 TLRs, Post Contingency Local Load Relief Warnings, and Non-Market Post Contingency Local Load Relief Warnings are excluded due to their high frequency.
131 PJM can recall energy exports as needed as part of triggering emergency procedures. See PJM. "PJM Manual 13: Emergency Operations," § 2.3.2 Real-Time Emergency Procedures (Warnings and Actions), Rev. 97 (Nov. 11, 2025).

Figure 3-52 shows the number of days for which emergency alerts were issued by PJM in the first three months of 2022 through 2026.

Figure 3-52 Number of days for which emergency alerts declared: January through March, 2022 through 2026

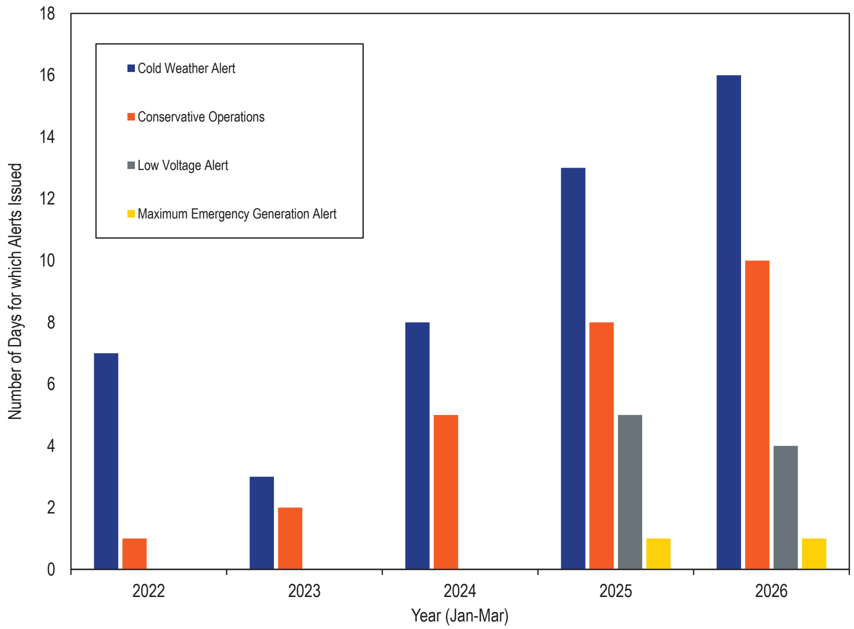


Figure 3-53 shows the number of days for which emergency warnings and actions were declared by PJM in the first three months of 2022 through 2026.

Figure 3-53 Declared emergency warnings and actions: January through March, 2022 through 2026

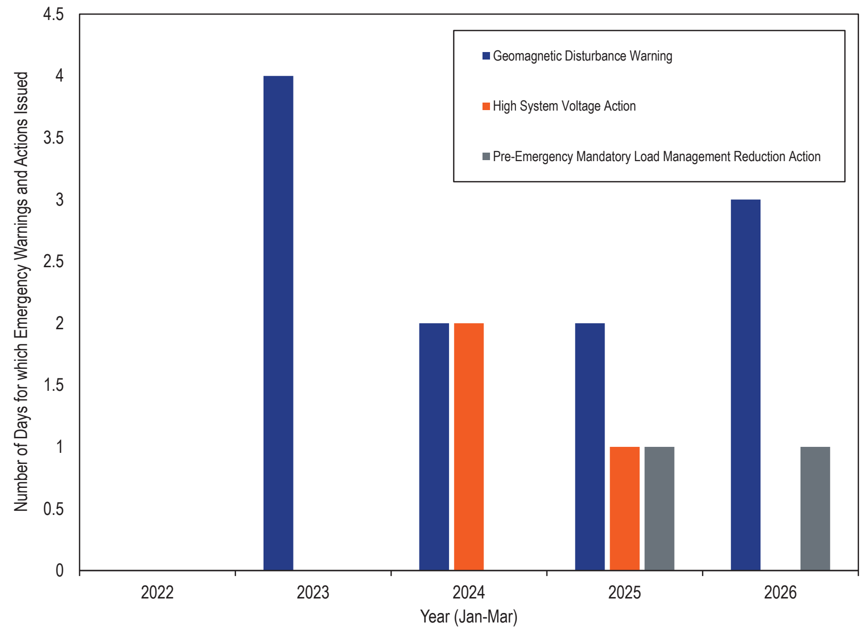


Figure 3-54 shows the number of post contingency local load relief warnings (PCLLRWs) and non-market post contingency local load relief warnings (NMPCLLRWs) declared in PJM in the first three months of 2026. Figure 3-55 shows the number of post-contingency local load relief warnings (PCLLRWs) for each area targeted by a PCLLRW's declaration. A single PCLLRW can be declared for multiple regions.

Figure 3-54 Declared local load relief warnings: January through March, 2026

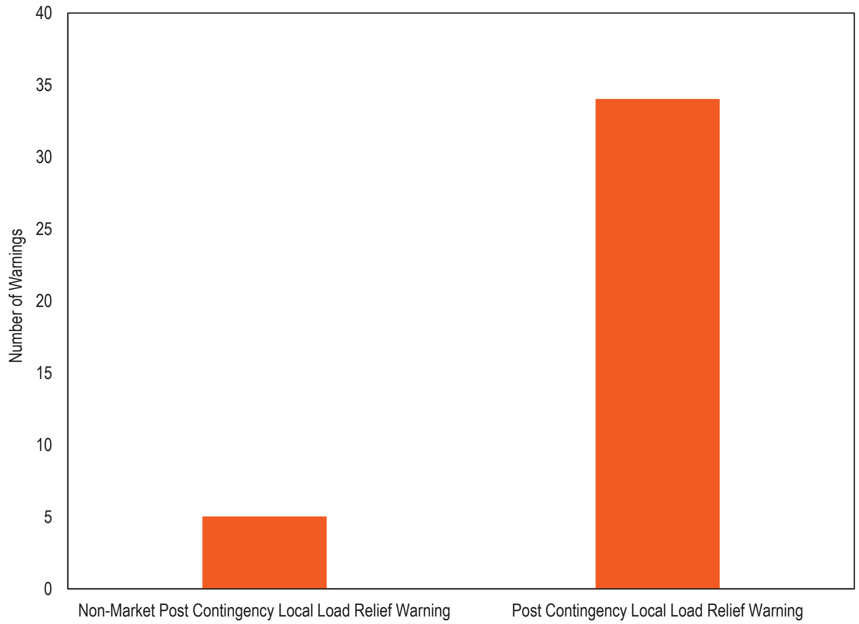
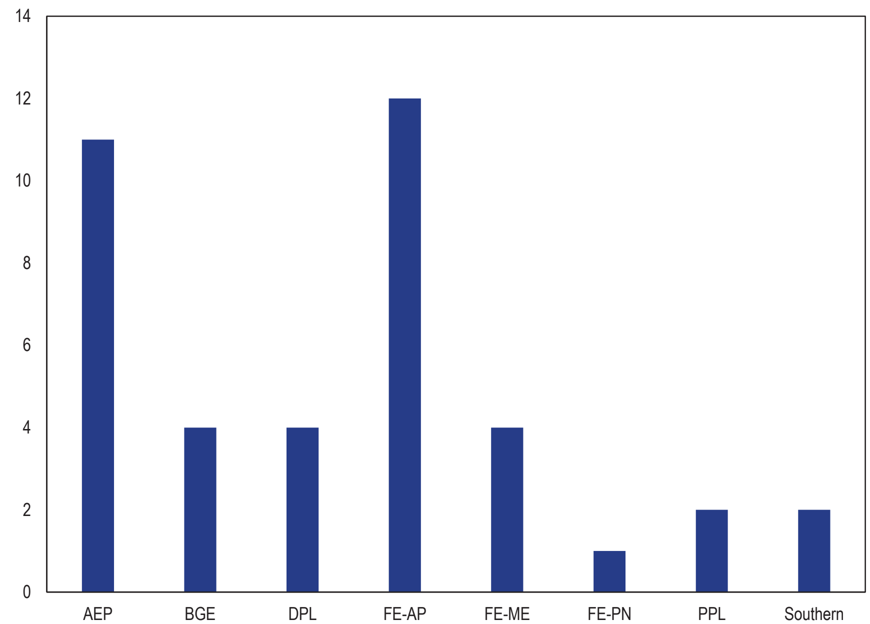


Figure 3-55 Number of post-contingency local load relief warnings per declared area: January through March, 2026



Power Balance Constraint Violation

The purpose of the real-time energy market is to dispatch sufficient supply to meet demand. In the RT SCED optimization, the power balance constraint enforces the requirement that total dispatched generation (supply) equals the sum total of forecasted load, losses and net interchange (demand). The power balance constraint is violated when supply is less than demand but, for a number of reasons, it is difficult to determine when there is an actual power balance constraint violation.

The current process for meeting energy and reserve requirements in real time, and pricing the system conditions when RT SCED forecasts that energy supply is less than the demand for energy and reserves, is opaque and not defined in the PJM governing documents. It is unclear whether and how PJM converts reserves to energy before violating the power balance constraint. It is unclear whether and when PJM uses its authority under the tariff to curtail exports from PJM capacity resources to meet the power balance constraint. It is unclear why PJM does not include demand side capacity resources in the definition of reserves. It is unclear whether PJM would maintain a minimum level of synchronized reserves even if that would result in a controlled load shed. The current RT SCED does not have a mechanism to convert inflexible reserves procured by the ASO to energy to satisfy the power balance constraint.[132] SCED solutions from October 1, 2019, February 16, 2020, and April 21, 2020, indicate that the defined logic met transmission constraint limits and reserve requirements but violated the power balance constraint. The definitions and implementation of reserves, combined with operator discretion to bias load, make it difficult to define when there is an actual power balance constraint violation. Effective August 8, 2024, PJM updated SCED and LPC to convert reserves to energy before violating the power balance constraint.

During Winter Storm Elliott, on December 23, and December 24, 2022, PJM created what PJM termed virtual generation in real time to satisfy the power balance constraint. PJM did not convert any inflexible reserves to energy. In summary, the power balance constraint was violated solely as a result of load bias added by PJM and that violation was corrected by PJM adding generation that does not actually exist to the supply (virtual generation). To the extent that there was not an actual violation of the power balance constraint, it was appropriate that PJM did not take actions to address the nonexistent violation.

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 include: the exact definition of the power balance constraint including the role of PJM load bias; a SCED process to economically convert reserves to energy; a process for the recall of energy from capacity resources to address any actual or potential power balance issue; a process to call on demand side capacity resources, and the minimum level of synchronized reserves that would trigger load shedding.

132 Inflexible reserves are those reserves that clear in the hour ahead Ancillary Service Optimizer (ASO) but cannot be dispatched in the real time dispatch tool, RT SCED.

Table 3-83 shows the number of five minute intervals for which the RT SCED solutions did not balance demand and supply. Prior to August 8, 2024, PJM reran the RT SCED with artificially increased supply to satisfy the power balance constraint. In the first three months of 2026, there were eight five-minute intervals that used an RT SCED solution with an apparently violated power balance constraint. Across all intervals with violations, PJM's positive load bias exceeded the apparent MW shortfall. Among those eight intervals, PJM capped the energy LMP at $3,700 per MWh for two intervals on March 12, 2026, and one interval on March 13, 2026.

Table 3-83 Number of five minute intervals using RT SCED solutions with apparently violated power balance constraint by year

Year	Number of five minute intervals	Average Energy Component of LMP in SCED ($/MWh)	Average Energy Component of LMP in Pricing Run ($/MWh)
2013	-	$0.00	$0.00
2014	655	$36.29	$36.29
2015	71	($0.76)	($0.76)
2016	42	$93.06	$93.06
2017	31	$279.86	$279.86
2018	16	$268.21	$268.21
2019	36	$845.48	$845.48
2020	5	$351.56	$351.56
2021	10	$976.06	$976.06
2022	121	$2,347.33	$2,066.21
2023	23	$357.34	$361.14
2024	6	$907.95	$907.95
2025	8	$3,408.63	$2,937.25
2026 (Jan - Mar)	8	$3,425.33	$3,311.49

Shortage and Shortage Pricing

In electricity markets, shortage means that demand, including reserve requirements, is nearing the limits of the currently available capacity of the system. Shortage pricing is a mechanism for signaling scarcity conditions through higher energy prices. Under the PJM rules that were in place through September 30, 2012, shortage pricing resulted from the exercise of aggregate market power by individual generation owners for specific units when the system was close to its available capacity. That was not an efficient way to manage shortage pricing and made it difficult to distinguish between market power and shortage pricing. Shortage pricing is an administrative pricing mechanism that sets a defined higher price when the system operates with real-time reserves that are lower than the target level.

In the first three months of 2026, there were 86 five minute intervals with real-time shortage pricing in the pricing run for one or more reserve products that occurred on 17 days in PJM.

In Order No. 825, the Commission required each RTO/ISO to trigger shortage pricing for any dispatch and pricing interval in which a shortage of energy or operating reserves is indicated by the RTO/ISO's software.[133] Prior to May 11, 2017, if the dispatch tools (Intermediate-Term SCED and Real-Time SCED) reflected a shortage of reserves (primary or synchronized) for a time period shorter than a defined threshold (30 minutes), it was considered a transient shortage, a shortage event was not declared, and shortage pricing was not implemented. As of May 11, 2017, the rule requires PJM to trigger shortage pricing for any five minute interval for which the Real-Time SCED (Security Constrained Economic Dispatch) indicates a shortage of synchronized reserves or primary reserves. In January 2019, PJM updated its business rules in Manual 11 to describe PJM's implementation of the five minute shortage pricing process. PJM Manual 11 states that shortage pricing is triggered when an approved RT SCED case that was used in the Locational Pricing Calculator (LPC) indicates a shortage of reserves. The implementation is not fully algorithmic or well defined because RT SCED can indicate a shortage that PJM does not use in pricing and because the load bias added to SCED may artificially create or suppress shortages. On June 22, 2020, PJM reduced the frequency of automatic RT SCED executions to every five minutes in order to match the frequency of pricing in the LPC, which reduced the frequency of unpriced shortage solutions.

Prior to September 1, 2021, the reserves calculated in the LPC solution, and the reserves calculated in the reference RT SCED case used by the LPC solution were the same. With the implementation of fast start pricing on September 1, 2021, shortage pricing is now triggered by the pricing run in LPC.[134] This can lead to differences between the dispatched reserves in RT SCED and the reserves calculated in the pricing run in LPC. In the pricing run in LPC, shortage pricing could be triggered even when there is no actual shortage in dispatched reserves as determined by the reference RT SCED solution. This occurred for six intervals in the first three months of 2026.

Voltage reduction actions and manual load dump actions are also triggers for shortage pricing, reflecting the fact that when operators need to take these emergency actions to maintain reliability, the system is short reserves and prices should reflect that condition, even if the power balance constraint is met and there is no defined shortage of reserves.[135]

Operating Reserve Demand Curves

Shortage pricing in the PJM Energy Market can occur in either the day-ahead or the real-time market for any of five reserve requirements: RTO Synchronized Reserves, Subzone Synchronized Reserves, RTO Primary Reserves, Subzone Primary Reserves, and 30-Minute Reserves. Each requirement is modelled in the market clearing engines as a demand curve priced administratively at $850 per MWh up to the minimum reserve requirement (MRR) and at $300 per MWh for additional reserves of at least 190 MW.[136] [137] The logic for the choice of the $850 shortage price is not defined by the market and its actual basis is not clear. During a reserve shortage, the marginal cost of the short reserve service is set to the administrative value of the ORDC ($850 per MWh if clearing less than the minimum reserve requirement, otherwise $300 per MWh). This is called shortage pricing, and this increases the LMP and the reserve product market clearing prices. This is why the values on the ORDC are sometimes called penalty factors. The penalty for being short of reserves is the increased cost administratively defined by the ORDC.

133 *Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 825, 155 FERC ¶ 61,276 at P 162 (2016).

134 *See* PJM Operating Agreement, Schedule 1 § 2.5.1(a).

135 *See, e.g.*, Scarcity and Shortage Pricing, Offer Mitigation and Offer Caps Workshop, Docket No. AD14-14-000, Transcript 29:21–30:14 (Oct. 28, 2014).

136 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.3.3 Reserve Demand Curves and Penalty Factors, Rev. 136 (Oct. 1, 2025).

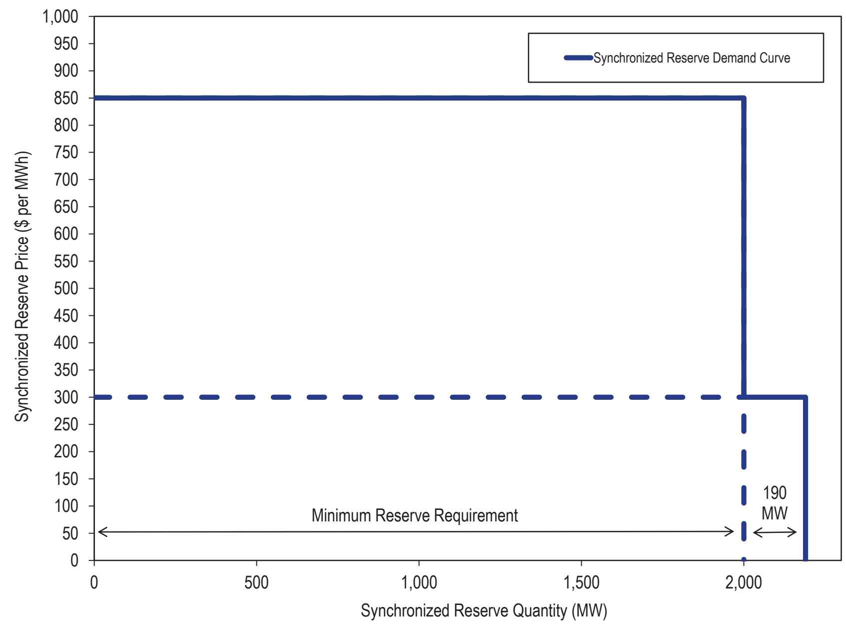
137 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.3 Reserve Requirement Determination, Rev. 136 (Oct. 1, 2025).

Mathematically, when a reserve constraint is not satisfied, the area under the administratively defined demand curve for the unmet MW of the reserve requirement is added to the market clearing cost minimization objective function as a penalty for violating a reserve constraint, which causes the administrative price on the ORDC to determine the marginal cost of the reserve shortage. Because an additional MW of energy on the margin would require another MW of reserves shortage, the administrative marginal cost of reserves defined by the ORDC is added to LMP.

Shortage Pricing and Energy Price Formation

The current operating reserve demand curves (ORDC) in PJM define an administrative price for estimated reserves (synchronized, primary, and 30-minute reserves) up to the extended reserve requirement quantities, which for each reserve service is the sum of that service's minimum reserve requirement (MRR) and an extended requirement of at least 190 MW. The price is $850 per MWh for reserve quantities less than the MRR. The price is $300 per MWh for reserve quantities between the MRR and the sum of the MRR and the extended requirement. The example demand curve shown in Figure 3-56 drops to a zero price for quantities above the extended reserve requirement.

Figure 3-56 Example real-time extended synchronized reserve demand curve showing the permanent second step



Historically, the minimum reserve requirement for each operating interval has equaled the size of the largest single source of supply on the PJM system during that operating interval, known as the most severe single contingency. Beginning May 12, 2023, PJM unilaterally increased the minimum reserve requirement based on what appeared to be low response rates from reserves but not based on any evidence about reliability issues. The changes to the reserve requirements are discussed in more detail in Section 10: Ancillary Service Markets.

Nesting

The reserve requirements are nested such that the reserves with shorter allowed response times and stricter synchronization requirements count toward the requirements for reserves with longer allowed response times and less strict synchronization requirements, and such that the reserves in the subzone count toward the total RTO requirement. For example, synchronized reserves count toward the primary reserve requirement, and Mid-Atlantic Dominion reserves count toward the PJM RTO reserve requirement. This nesting means that the effect of reserve constraints on prices can be additive.

The effect of the reserve constraints on pricing depends on the constraint shadow price. The market uses constraints to ensure that reliability requirements are met while production costs are minimized. A binding constraint means that the market incurred some additional production cost to satisfy the constraint. A violated constraint has no associated production cost, so an administrative cost is used instead. The shadow price of a constraint is the change in the total production cost (the objective function of the market dispatch software) if that constraint limit were increased at the margin. A reserve constraint violation (a shortage) means that the constraint cannot be satisfied at a defined marginal cost, and the administratively defined cost is used instead. For the RTO synchronized reserve constraint, the shadow price during a shortage is defined to equal the ORDC value. For the MAD synchronized reserve constraint, when reserves from both the RTO and MAD can be used, the shadow price equals the sum of the ORDC value for each constraint when both are violated. The same occurs for the primary and 30-minute reserve constraints. The total shadow price of reserve violations can reach five times the highest ORDC value of $850 per MWh, which is $4,250 per MWh. This value exceeds the PJM $1,700 per MWh price caps on reserve prices and the $3,700 per MWh price cap applied to the energy component of LMP (the system marginal price or SMP component of LMP). There is no underlying economic analysis that supports these extremely high prices when reserves are short. There is no evidence that the demand for electricity responds to these high prices which generally occur during extreme weather when the demand and need for power is high.

Energy and Reserve Price Caps

Table 3-84 shows six example scenarios, under the current ORDCs, with combinations of energy offers, reserve shortage penalty factors and transmission constraint penalty factors that can add up to produce high LMPs at sample pnodes in the MAD Reserve Subzone and outside the MAD Reserve Subzone.

Scenario A shows a simple shortage in the RTO Reserve Zone. In scenario B, there is a reserve shortage for both primary and synchronized reserves in both MAD and RTO Reserve Zones that results in a $1,700 per MWh reserve shortage penalty in the RTO Zone LMP and a $3,400 per MWh reserve shortage penalty in the MAD Zone LMP. The marginal resource for energy is in the RTO Zone. The RTO to MAD reserve transfer constraint is binding, so the higher MAD reserve penalty does not affect the rest of RTO LMP.

In scenario C, there is a reserve shortage for both primary and synchronized reserves in both MAD and RTO Reserve Zones and a violated transmission constraint that affects the marginal congestion costs in the system marginal price. In scenario C, the sum of the marginal unit cost, reserve and transmission constraint penalty factors equals $5,450 per MWh, which exceeds $3,700 per MWh, so SMP capping is triggered whether the marginal unit for energy can provide reserves for the MAD Zone or only the RTO Zone.

In scenario D, with a $1,000 per MWh offer price for the marginal unit for energy, violation of four reserve penalty factors does not trigger SMP capping, because the marginal unit for energy cannot serve the MAD reserve requirement. Scenario E and F show that LMPs can exceed $3,700 per MWh if there is a violated transmission constraint that is not exacerbated by an increase in load at the load weighted reference pricing node, which determines the SMP.[138]

In Scenario F, the energy component of LMP is at its highest level, $2,000 per MWh and there is a reserve shortage for primary and synchronized reserves in both MAD and RTO Reserve Zones and a shortage of 30 minute reserves, resulting in a capped $1,700 per MWh scarcity adder, and a violated transmission constraint with a $2,000 per MWh penalty factor that results in a $5,700 per MWh LMP. The LMPs in Scenario F are not the highest possible LMPs in the PJM energy market under the current rules. If there are multiple

138 The impact of the transmission constraint penalty factor at a pnode depends on its distribution factor (dfax) with respect to the constraint. The scenarios here assume a single violated transmission constraint with dfax of 1.0. If there are multiple violated transmission constraints, the total impact at a pnode is the sum of the product of transmission constraint penalty factors and distribution factors.

violated transmission constraints, the congestion costs contributing to the LMP at a pnode can exceed $2,000 per MWh resulting in LMPs higher than $5,700 per MWh.

Scenarios G and H are similar to conditions during the highest priced hours of Winter Storm Elliott on December 23 and 24, 2022. In G, the marginal unit offer price is $500 per MWh. The synchronized and primary reserve requirements are violated for the RTO and MAD zones. Transmission constraints affect both the system marginal price and other locations. The SMP in G is capped at $3,700 per MWh. In H, the marginal unit offer price is lower, at $40 per MWh, and the 30 minute reserve constraint is also violated. With the offer caps, the SMP is also at $3,700 per MWh.

The extent to which each transmission constraint penalty factor for a constraint affects the LMP at a pnode is directly proportional to the pnode's distribution factor (dfax) with respect to that constraint. In addition, the LMP at a pnode includes a loss component calculated as the product of the marginal loss factor and the uncapped system marginal price.

Table 3-84 Real-time additive penalty factors under reserve shortage and transmission constraint violations: Status Quo

	Marginal Unit	Synchronized Reserve Penalty Factor		Primary Reserve Penalty Factor		30 Minute Reserve Penalty Factor	Transmission Constraint Penalty Factor	System Marginal Price		Transmission Constraint Penalty Factor	Total LMP	
Scenario	Offer Price	RTO	MAD	RTO	MAD	RTO	in SMP	RTO Marginal	MAD Marginal	in CLMP	RTO Marginal	MAD Marginal
A	$50	$850	$0	$0	$0	$0	$0	$900	$900	$0	$900	$900
B	$50	$850	$850	$850	$850	$0	$0	$1,750	$3,450	$0	$1,750	$3,450
C	$50	$850	$850	$850	$850	$0	$2,000	$3,700	$3,700	$0	$3,700	$3,700
D	$1,000	$850	$850	$850	$850	$0	$0	$2,700	$3,700	$0	$2,700	$3,700
E	$1,000	$850	$850	$850	$850	$850	$2,000	$3,700	$3,700	$2,000	$5,700	$5,700
F	$2,000	$850	$850	$850	$850	$850	$2,000	$3,700	$3,700	$2,000	$5,700	$5,700
G	$500	$850	$850	$850	$850	$0	$2,000	$3,700	$3,700	$2,000	$5,700	$5,700
H	$40	$850	$850	$850	$850	$850	$2,000	$3,700	$3,700	$2,000	$5,700	$5,700

Shortage Pricing During Synchronized Reserve Events

Synchronized reserves are deployed when PJM declares a synchronized reserve event, also known as a spinning event. PJM's method of communication prior to December 2024 failed to result in reliably timely responses, defined to be within 10 minutes. For units that could receive an electronic signal, PJM's instruction to units supplying reserves was to ignore the dispatch signals sent by RT SCED and to instead ramp their units up until the spin event ends. A significant number of resources did not have the capability to receive the electronic signals that PJM offered. The ALL-CALL system only calls a limited number of contacts at the same time. Although PJM's stated goal was an immediate response, in practice it took minutes for a generator's designated contact to respond to the ALL-CALL, who could then take minutes more to call personnel at the plant. If a unit was following automatic generation control when an event was declared, then additional minutes could also be lost switching to manual control. The end result of these communications issues was that resources started responding only after minutes into an event, even when everything went well.[139] In December 2024, PJM added an automated communication method that would add the reserve deployment instruction to the dispatch signal, which will allow generators following automatic generation control to automatically follow the signal. The new method did not affect any synchronized reserve events in 2024. The new method applied to the 28 events in 2025 (of which only seven lasted at least ten

139 See the *2024 State of the Market Report for PJM*, Volume 2, Section 10: Ancillary Service Markets for a more detailed discussion of these issues.

minutes) and the eight events in the first three months of 2026 (of which only one lasted at least ten minutes). Synchronized reserve performance improved in 2025 and the first three months of 2026. The new method did not resolve the communications issues for all resources. Significant communications issues remain unresolved.

Although PJM signals resources to increase their output, the approved SCED cases are solved with the reserve requirement intact, which dispatches the system to meet the load and reserve requirements 8 to 10 minutes into the future. Currently, RT SCED has the ability to back down units during events to create available reserves, which counteracts PJM's recovery effort. This results in a discrepancy between the RT SCED solutions and the operational need during a spinning event. While PJM recovers from a disturbance during a spinning event, PJM should adjust the operating reserve demand curve (ORDC) for synchronized reserves to ensure that RT SCED does not have a competing objective of immediately replacing reserves that have been paid for and are being used as intended. Without such an adjustment, the prices are artificially inflated, potentially triggering shortage pricing, during the times when reserves are used for their intended purpose. For example, ten shortage pricing intervals were artificially triggered during the spin event on March 1, 2026. The MMU recommends that PJM adjust the ORDCs during spin events to reduce the reserve requirements by the amount of the reserves deployed.

Reserve Shortages First Three Months of 2026

Reserve Shortage in Real-Time SCED

The MMU analyzed the RT SCED solutions to determine how many of the five minute target time RT SCED solutions indicated a shortage of any of the reserve products in the RTO Reserve Zone and the MAD Reserve Subzone (synchronized reserve and primary reserve in both areas and 30-minute reserve in the RTO), when multiple solutions indicated shortage of reserves, and how many of these resulted in shortage prices in LPC. Reserves are considered short if the quantity (MW) of reserves dispatched by RT SCED for a five minute interval is less than the extended reserve requirement. To trigger shortage pricing, PJM operators must approve an LPC case in which the MW of reserves in the pricing run of the LPC are short of the extended reserve requirement.

Until June 2, 2021, PJM generally solved one RT SCED case with three solutions per case, for each five minute target time.[140] [141] On June 3, 2021, PJM updated RT SCED to solve two additional scenarios, or a total of five solutions per case. In 2021, the frequency with which RT SCED solutions were approved increased to one solution per five minute interval. This approval frequency increased the proportion of approved SCED solutions that are reflected in LMPs. However, the process of selecting the SCED solution to approve, among the solutions available to PJM operators, is subjective and is not based on clearly defined criteria. The criteria are especially important when only some of the SCED solutions reflect shortage pricing.

The MMU analyzed the target times for which one or more RT SCED case solutions indicated a shortage of one or more reserve products. Table 3-85 shows, in 2025 and the first three months of 2026, the total number of target times, the number of target times for which at least one RT SCED solution showed a shortage of reserves, the number of target times for which multiple RT SCED solutions showed a shortage of reserves, and the number of five-minute pricing intervals for which the LPC solution showed a shortage of reserves. Each execution of RT SCED produces five solutions, using five different levels of load bias. Table 3-85 shows that, in 2025, 5,496 target times, or 5.2 percent of all five-minute target times, had at least one RT SCED solution showing a shortage of reserves, and 1,824 target times, or 1.7 percent of all five-minute target times, had more than one RT SCED solution showing a shortage of reserves. In the first three months of 2026, there were 1,445 target times, or 5.6 percent of all five-minute target times, that had at least one RT SCED solution showing a shortage of reserves, and 486 target times, or 1.9 percent of all five-minute target times, that had multiple RT SCED solutions showing a shortage of reserves.

140 A case is executed when it begins to solve. Most but not all cases are solved. RT SCED cases take about one to two minutes to solve.

141 PJM updated the RT SCED execution frequency to solve one case for each five minute target time beginning June 22, 2020. PJM dispatchers may solve additional cases at their discretion.

Table 3-85 Real-time monthly five minute SCED target times and pricing intervals with shortage: January 2025 through March 2026

Year	Month	Number of Five Minute Intervals	Number of Target Times With At Least One SCED Solution Short of Reserves	Percent Target Times With At Least One SCED Solution Short of Reserves	Number of Target Times With Multiple SCED Solutions Short of Reserves	Percent Target Times With Multiple SCED Solutions Short of Reserves	Number of Five Minute Intervals With Shortage Prices in LPC	Percent RT SCED Target Times With Reserve Shortage With Shortage Prices in LPC
2025	Jan	8,928	398	4.5%	119	1.3%	10	2.5%
2025	Feb	8,352	606	7.3%	156	1.9%	0	0.0%
2025	Mar	8,916	876	9.8%	259	2.9%	9	1.0%
2025	Apr	8,640	434	5.0%	103	1.2%	2	0.5%
2025	May	8,928	792	8.9%	249	2.8%	1	0.1%
2025	Jun	8,640	404	4.7%	115	1.3%	2	0.5%
2025	Jul	8,928	390	4.4%	118	1.3%	3	0.8%
2025	Aug	8,928	532	6.0%	119	1.3%	0	0.0%
2025	Sep	8,640	687	8.0%	223	2.6%	2	0.3%
2025	Oct	8,928	654	7.3%	205	2.3%	6	0.9%
2025	Nov	8,652	645	7.5%	157	1.8%	1	0.2%
2025	Dec	8,928	393	4.4%	82	0.9%	3	0.8%
2025	Total	105,408	6,811	6.5%	1,905	1.8%	39	0.6%
2026	Jan	8,928	293	3.3%	102	1.1%	24	8.2%
2026	Feb	8,064	493	6.1%	171	2.1%	41	8.3%
2026	Mar	8,916	659	7.4%	213	2.4%	21	3.2%
2026	Total	25,908	1,445	5.6%	486	1.9%	86	6.0%

As shown in Table 3-85, in 2025, there were 1,824 unique five-minute target times for which multiple RT SCED solutions showed a shortage of reserves for one or more reserve services, while there were 147 unique five-minute intervals with real-time shortage pricing for one or more reserve products. In the first three months of 2026, there were 486 unique five-minute target times for which multiple RT SCED solutions showed a shortage of reserves for one or more reserve services, while there were 86 unique five minute intervals with real-time shortage pricing for one or more reserve products. Clear criteria for approval of shortage cases are needed.

The PJM Real-Time Energy Market produces an efficient outcome only when prices are allowed to reflect the fundamental supply and demand conditions in the market in real time. There are two related issues, the definition of a shortage and the definition of an efficient shortage price. While it is appropriate for operators to ensure that cases use data that reflect the actual state of the system, it is essential that operator discretion not extend beyond what is necessary and that operator discretion not prevent shortage pricing when there are shortage conditions or implement shortage pricing when there are no shortage conditions. This is a critical issue now that PJM settles all real-time energy transactions on a five minute basis using the prices calculated by LPC. 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. A rule based approach is essential for defining how LMPs are determined so that all market participants can be confident that energy market pricing is efficient. However, whether the triggered shortage pricing results in an efficient outcome is a function both of the rules defining a shortage and the level of shortage pricing. It has not been demonstrated that PJM's administratively defined shortage pricing is efficient.

Prolonged and excessively high administrative shortage pricing in the energy market would impose inefficient wealth transfers. Inefficient wealth transfers from load to generation, among generators, or from physical to financial market participants occur when administrative pricing creates arbitrarily high price signals to which participants cannot respond. A solution would be to lower the default emergency pricing levels to avoid inefficient wealth transfers while providing an appropriate price signal.

Shortage Pricing Intervals in LPC

Beginning October 1, 2022, shortage pricing can occur in both the PJM Day-Ahead and Real-Time Energy Markets for Synchronized Reserves, Primary Reserves, and 30-Minute Reserves.

In May 2023, PJM increased reserve requirements in response to poor reserve performance by the units selected to provide reserves. PJM unilaterally increased the synchronized reserve reliability requirement by 30 percentage points to 130 percent of the most severe single contingency (MSSC), which consequently increased the primary reserve reliability requirement by 45 percentage points to 195 percent of the MSSC. On January 9, 2026, the synchronized reserve reliability requirement was decreased by 10 percentage points to be 120 percent of the MSSC, which made the primary reserve reliability requirement 130 percent of the MSSC. While the intervals listed in this section were short of their target requirements, many of these intervals still cleared above the average values of the requirements from before the increase. The average primary reserve requirement from January 2023 through April 2023 was 2,511.4 MW and the average synchronized reserve requirement was 1,741.7 MW. Many of the intervals with shortage pricing were not short in the sense of failing to clear a sufficient amount of reserves for recovering from a contingency event. They were short because of PJM's unilateral increase to the synchronized reserve reliability requirement. Table 3-86 shows the count of intervals with shortage pricing for synchronized reserve (SR), primary reserve (PR), and 30-minute reserve (TMR) in the RTO. As seen in Table 3-86, the majority of intervals with shortage pricing cleared reserves in excess of the original reserve requirements absent PJM's adder. The adder does not apply to the MAD Reserve Subzone.

Table 3-86 Number of shortage pricing intervals which satisfied the unmodified reserve service requirement: January through March, 2026

	Reserve Service		
	SR	PR	TMR
Intervals with Shortage Pricing	22	76	0
Intervals where RT SCED Satisfied Original Requirement	22	58	0
Percentage of Intervals where RT SCED Satisfied Original Requirement	100.0%	76.3%	NA
Intervals where RT SCED Did Not Satisfy Original Requirement	0	18	0

There were 86 unique real-time five-minute intervals with shortage pricing for one or more reserve products in the first three months of 2026, compared to 14 intervals in the first three months of 2025. In the first three months of 2026, there were 80 unique real-time five-minute intervals with shortage in the dispatch run for one or more reserve products, compared to 14 intervals in 2025. Table 3-87 through Table 3-90 show intervals with shortage pricing in the pricing run for each reserve service for the RTO Reserve Zone and the MAD Reserve Subzone. PJM implemented fast start pricing on September 1, 2021. Fast start pricing can result in differences in reserve shortages between the dispatch run and the pricing run. This applied to six intervals in the first three months of 2026.

In 2025, there were four hours with shortage pricing in the day-ahead reserve markets. In the first three months of 2026, there were four unique day-ahead hours with shortage pricing for one or more reserve products. For January 27, 2026, in the day-ahead market, there were two hours with shortage pricing for synchronized reserves in the RTO Reserve Subzone. For January 28, 2026, in the day-ahead market, there were two hours with shortage pricing for primary reserves in the RTO Reserve Zone.

Table 3-87 shows the extended synchronized reserve requirement, the total synchronized reserves, the synchronized reserve shortage, and the synchronized reserve clearing prices for the RTO Reserve Zone during the 22 intervals with shortage pricing in the pricing run due to synchronized reserve shortage in the first three months of 2026. Table 3-87 shows that the 22 intervals were short of synchronized reserves in both the pricing run and the dispatch run. Six intervals were also short of synchronized reserves in MAD in the pricing and dispatch run. Twelve intervals were also short of primary reserves in the RTO in the pricing and dispatch runs. Nine intervals were also short of primary reserves in MAD in the pricing and dispatch runs. Three intervals overlapped with a spinning event on March 1, 2026.

Table 3-88 shows the extended synchronized reserve requirement, the total synchronized reserves, the synchronized reserve shortage, and the synchronized reserve clearing prices for the MAD Reserve Subzone during the six intervals with shortage pricing in the pricing run due to synchronized reserve shortage in the first three months of 2026. Table 3-88 shows that the six intervals were short of synchronized reserves in both the pricing run and the dispatch run. Five intervals were also short of primary reserves in the RTO in the pricing and dispatch run. Three intervals were also short of primary reserves in the MAD Reserve Subzone in the pricing and dispatch run.

Table 3-89 shows a summary of the extended primary reserve requirement, the total primary reserves, the primary reserve shortage, and the primary reserve clearing prices for the RTO Reserve Zone during the 76 intervals with shortage pricing in the pricing run due to primary reserve shortage in the first three months of 2026. The full version of Table 3-89 is published separately.[142] Of the 76 intervals with shortage pricing in the pricing run, 70 were short in both the pricing run and the dispatch run. Fourteen intervals were also short of primary reserve in the MAD Reserve Subzone in the pricing run and twelve were short in the dispatch run. Twelve intervals were also short of synchronized reserve in the RTO Reserve Zone in the dispatch run and pricing run. Five intervals were also short of synchronized reserve in the MAD Reserve Subzone in the dispatch run and pricing run. The three intervals on March 1 overlapped with a synchronized reserve event.

Table 3-90 shows the extended primary reserve requirement, the total primary reserves, the primary reserve shortage, and the primary reserve clearing prices for the MAD Reserve Subzone during the 14 intervals with shortage pricing in the pricing run due to primary reserve shortage in the first three months of 2026. Table 3-89 shows that 12 of the 14 intervals were short of primary reserves in both the pricing run and the dispatch run. Fourteen intervals were also short of primary reserves in the RTO Reserve Zone in the pricing run and twelve were short in the dispatch run. Nine intervals were also short of synchronized reserve in the RTO Reserve Zone in the pricing run and the dispatch run. Three intervals were also short of synchronized reserve in the MAD Reserve Subzone in the pricing run and the dispatch run. The intervals on March 1 overlapped with a synchronized reserve event.

PJM enforces an RTO wide reserve requirement and a reserve requirement for the MAD region. The MAD Reserve Subzone is inside the RTO Reserve Zone. Resources located in the MAD Reserve Subzone can simultaneously satisfy the synchronized reserve requirement of the RTO Reserve Zone and the synchronized reserve requirement of the MAD Reserve Subzone. Resources located outside the MAD Reserve Subzone can satisfy the synchronized reserve requirement of the RTO Reserve Zone, and subject to transfer limits defined by transmission constraints, satisfy the reserve requirement of the MAD Subzone. The synchronized reserve clearing price of the RTO Reserve Zone is set by the shadow price of the binding reserve requirement constraint of the RTO Reserve Zone.[143] The synchronized reserve clearing price of the MAD Reserve Subzone is set by the sum of the shadow prices of the binding reserve requirement constraint of the RTO Reserve Zone and the shadow price of the binding reserve requirement constraint of the MAD Reserve Subzone.

The MCP for secondary reserves is capped by the PJM tariff at the 30-minute reserve penalty factor for the RTO ($850 per MWh).[144] The MCP for nonsynchronized reserves is capped at one and a half times the primary reserve penalty factor for each zone or subzone ($1,275 per MWh).[145] The MCP for synchronized reserves is capped at the sum of two of the three penalty factors for synchronized reserve, primary reserve, and 30-minute reserve ($1,700 per MWh).[146] However, the PJM tariff does not explicitly specify a

142 See Monitoring Analytics LLC, "Reserve Shortages," (May 14, 2026) <https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2026/IMM_Reserve_Shortages_20260514.xlsx>.

143 If the reserve requirement cannot be met by the resources located within the reserve zone, the shadow price of the reserve requirement is set by the applicable operating reserve demand curve.

144 OATT, Attachment K - Appendix § 3.2.3A.01(d).

145 OATT, Attachment K - Appendix § 3.2.3A.001(c).

146 OATT, Attachment K - Appendix § 3.2.3A(d).

cap on the system marginal price. The system marginal price cap of $3,700 per MWh that is actually applied by PJM should be included in the PJM tariff and Operating Agreement.

The intervals with 0.00001 shortage MW in Table 3-87 and the full version of Table 3-89[147] were not truly short; they result from a software issue. PJM sets the synchronized reserve requirement for the RTO based on the largest generation contingency in the entire PJM system, including the MAD Reserve Subzone. Similarly, PJM sets the synchronized reserve requirement of the MAD Reserve Subzone based on the largest generation contingency located within the MAD Reserve Subzone. When the largest generation contingency on the system is located in the MAD Reserve Subzone, both the MAD and the RTO reserve requirements are set by the same generation contingency, and the reserve requirement quantities for MAD and RTO are identical. In the real-time market clearing software, to avoid an issue with inaccurate prices that result from such situations, the software adds a small quantity (0.00001 MW) to the RTO reserve requirement, to differentiate the constraint from the MAD reserve requirement constraint.[148] When the RT SCED solves with the RTO reserve requirement short by this quantity (0.00001 MW), there is no actual shortage of reserves, since this was an artificially added quantity to resolve a modeling issue. The market clearing prices for reserves and the LMPs should not include the penalty factor for the reserve product when the reserves are short by 0.00001 MW. The market clearing prices and LMPs during these intervals are not stated in the shortage pricing rules in the PJM tariff. Embedding a rule in nontransparent market software is not the same thing as including an explicit rule in the tariff.

The process of calculating reserve constraint shadow prices and implementing reserve price caps in PJM is not clearly defined or transparent. The MMU recommends that PJM clearly document the calculation of shortage prices and implementation of reserve price caps in the PJM manuals, including definitions of all the components of reserve prices, and all the constraints whose shadow prices are included in reserve prices.

147 For the full version, see Monitoring Analytics LLC, "Reserve Shortages," (May 14, 2026) <https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2026/IMM_Reserve_Shortages_20260514.xlsx>.
148 Adding 0.00001 MW only to the RTO reserve requirement constraint ensures that the MAD reserve requirement constraint is violated before the violation of the RTO reserve requirement constraint. However, this modeling feature may result in situations where it might be cheaper for the market to not satisfy 0.00001 MW of reserves and incur a small penalty ($850*0.00001). Under those conditions, PJM system would show 0.00001 MW shortage.

Table 3-87 Real-time RTO synchronized reserve shortage intervals: January through March, 2026

	Pricing Run					Dispatch Run				
Interval (EPT)	RTO Extended Synchronized Reserve Requirement (MW)	Total RTO Synchronized Reserves (MW)	RTO Synchronized Reserve Shortage (MW)	Uncapped RTO Synchronized Reserve Clearing Price ($/MWh)	Capped RTO Synchronized Reserve Clearing Price ($/MWh)	RTO Extended Synchronized Reserve Requirement (MW)	Total RTO Synchronized Reserves (MW)	RTO Synchronized Reserve Shortage (MW)	Uncapped RTO Synchronized Reserve Clearing Price ($/MWh)	Capped RTO Synchronized Reserve Clearing Price ($/MWh)
23-Jan-26 17:50	2,448.4	1,692.9	755.475	$850.00	$850.00	2,448.4	1,692.9	755.475	$850.00	$850.00
24-Jan-26 05:35	2,451.8	2,317.3	134.435	$1,150.00	$1,150.00	2,451.8	2,317.3	134.435	$1,150.00	$1,150.00
24-Jan-26 05:40	2,456.1	2,066.4	389.673	$1,700.00	$1,700.00	2,456.1	2,066.4	389.673	$1,700.00	$1,700.00
30-Jan-26 17:50	1,920.0	1,920.0	0.000	$300.00	$300.00	1,920.0	1,920.0	0.000	$300.00	$300.00
01-Feb-26 03:20	1,904.0	1,904.0	0.000	$300.00	$300.00	1,904.0	1,904.0	0.000	$300.00	$300.00
01-Feb-26 03:30	1,904.0	1,904.0	0.000	$300.00	$300.00	1,904.0	1,904.0	0.000	$300.00	$300.00
01-Feb-26 03:50	1,904.0	1,904.0	0.000	$300.00	$300.00	1,904.0	1,904.0	0.000	$300.00	$300.00
01-Feb-26 08:15	1,930.0	1,930.0	0.000	$300.00	$300.00	1,930.0	1,930.0	0.000	$300.00	$300.00
04-Feb-26 22:25	1,917.0	1,917.0	0.000	$300.00	$300.00	1,917.0	1,917.0	0.000	$300.00	$300.00
06-Feb-26 18:00	1,898.0	1,898.0	0.000	$300.00	$300.00	1,898.0	1,898.0	0.000	$300.00	$300.00
07-Feb-26 18:05	1,920.0	1,920.0	0.000	$300.00	$300.00	1,920.0	1,920.0	0.000	$300.00	$300.00
01-Mar-26 19:30	2,417.6	2,032.6	384.958	$1,700.00	$1,700.00	2,417.6	2,032.6	384.958	$1,700.00	$1,700.00
01-Mar-26 19:35	2,413.5	1,915.6	497.929	$1,700.00	$1,700.00	2,413.5	1,915.6	497.929	$1,700.00	$1,700.00
12-Mar-26 18:55	2,386.6	1,903.0	483.575	$1,700.00	$1,700.00	2,386.6	1,903.0	483.575	$1,700.00	$1,700.00
12-Mar-26 19:00	2,392.8	1,868.0	524.829	$1,700.00	$1,700.00	2,392.8	1,868.0	524.829	$1,700.00	$1,700.00
12-Mar-26 19:05	2,387.0	2,223.2	163.744	$1,150.00	$1,150.00	2,387.0	2,223.2	163.744	$1,150.00	$1,150.00
12-Mar-26 19:10	2,391.2	1,730.3	660.883	$1,700.00	$1,700.00	2,391.2	1,730.3	660.883	$1,700.00	$1,700.00
13-Mar-26 07:10	2,401.7	2,299.1	102.605	$1,150.00	$1,150.00	2,401.7	2,299.1	102.605	$1,150.00	$1,150.00
13-Mar-26 07:15	2,408.0	1,452.5	955.472	$1,700.00	$1,700.00	2,408.0	1,452.5	955.472	$1,700.00	$1,700.00
13-Mar-26 07:20	2,405.9	1,364.6	1,041.279	$1,700.00	$1,700.00	2,405.9	1,364.6	1,041.279	$1,700.00	$1,700.00
13-Mar-26 07:25	2,402.6	1,934.6	468.000	$1,700.00	$1,700.00	2,402.6	1,934.6	468.000	$1,700.00	$1,700.00
14-Mar-26 00:30	2,360.8	2,309.5	51.290	$300.00	$300.00	2,360.8	2,309.5	51.290	$300.00	$300.00

Table 3-88 Real-time MAD synchronized reserve shortage intervals: January through March, 2026

	Pricing Run					Dispatch Run				
Interval (EPT)	MAD Extended Synchronized Reserve Requirement (MW)	Total MAD Synchronized Reserves (MW)	MAD Synchronized Reserve Shortage (MW)	Uncapped MAD Synchronized Reserve Clearing Price ($/MWh)	Capped MAD Synchronized Reserve Clearing Price ($/MWh)	MAD Extended Synchronized Reserve Requirement (MW)	Total MAD Synchronized Reserves (MW)	MAD Synchronized Reserve Shortage (MW)	Uncapped MAD Synchronized Reserve Clearing Price ($/MWh)	Capped MAD Synchronized Reserve Clearing Price ($/MWh)
23-Jan-26 17:50	1,877.0	1,692.9	184.1	$1,150.00	$1,150.00	1,877.0	1,692.9	184.1	$1,150.00	$1,150.00
12-Mar-26 18:55	1,907.0	1,903.0	4.0	$2,000.00	$1,700.00	1,907.0	1,903.0	4.0	$2,000.00	$2,000.00
12-Mar-26 19:00	1,907.0	1,868.1	39.0	$2,000.00	$1,700.00	1,907.0	1,868.1	39.0	$2,000.00	$2,000.00
12-Mar-26 19:10	1,908.0	1,730.3	177.7	$2,850.00	$1,700.00	1,908.0	1,730.3	177.7	$2,850.00	$2,850.00
13-Mar-26 07:15	1,917.0	1,452.5	464.5	$3,400.00	$1,700.00	1,917.0	1,452.5	464.5	$3,400.00	$3,400.00
13-Mar-26 07:20	1,916.0	1,364.6	551.4	$3,400.00	$1,700.00	1,916.0	1,364.6	551.4	$3,400.00	$3,400.00

Table 3-89 Daily summary of real-time RTO primary reserve shortage intervals: January through March, 2026[149]

		Pricing Run					Dispatch Run				
Day (EPT)	Intervals of Shortage	Average RTO Extended Primary Reserve Requirement (MW)	Average Total RTO Primary Reserves (MW)	Average RTO Primary Reserve Shortage (MW)	Average Uncapped RTO Primary Reserve Clearing Price ($/MWh)	Average Capped RTO Primary Reserve Clearing Price ($/MWh)	Average RTO Extended Primary Reserve Requirement (MW)	Average Total RTO Primary Reserves (MW)	Average RTO Primary Reserve Shortage (MW)	Average Uncapped RTO Primary Reserve Clearing Price ($/MWh)	Average Capped RTO Primary Reserve Clearing Price ($/MWh)
24-Jan-26	6	3,582.6	3,254.2	328.393	$575.00	$575.00	3,582.6	3,260.9	321.738	$555.43	$555.43
31-Jan-26	16	2,741.7	2,741.7	0.000	$300.00	$300.00	2,741.7	2,741.7	0.000	$300.00	$300.00
2-Feb-26	12	2,777.5	2,777.5	0.000	$300.00	$300.00	2,777.5	2,777.5	0.000	$288.29	$288.29
6-Feb-26	5	2,770.3	2,770.3	0.000	$300.00	$300.00	2,770.3	2,770.3	0.000	$300.00	$300.00
9-Feb-26	15	2,749.5	2,597.3	152.219	$410.00	$410.00	2,749.5	2,601.1	148.424	$404.24	$404.24
13-Feb-26	1	2,792.5	2,792.5	0.000	$300.00	$300.00	2,792.5	2,792.5	0.000	$300.00	$300.00
16-Feb-26	1	3,430.0	3,420.3	9.745	$300.00	$300.00	3,430.0	3,420.3	9.745	$300.00	$300.00
1-Mar-26	3	3,524.1	2,718.1	805.961	$850.00	$850.00	3,524.1	2,718.1	805.961	$850.00	$850.00
12-Mar-26	9	3,489.3	2,951.0	538.322	$727.78	$727.78	3,489.3	2,951.5	537.868	$727.78	$727.78
13-Mar-26	7	3,513.5	2,711.2	802.329	$700.57	$700.57	3,513.5	2,711.2	802.329	$700.57	$700.57
22-Mar-26	1	3,403.0	3,364.9	38.053	$300.00	$300.00	3,403.0	3,364.9	38.053	$300.00	$300.00

Table 3-90 Real-time MAD primary reserve shortage intervals: January through March, 2026

	Pricing Run					Dispatch Run				
Interval (EPT)	MAD Extended Primary Reserve Requirement (MW)	Total MAD Primary Reserves (MW)	MAD Primary Reserve Shortage (MW)	Uncapped MAD Primary Reserve Clearing Price ($/MWh)	Capped MAD Primary Reserve Clearing Price ($/MWh)	MAD Extended Primary Reserve Requirement (MW)	Total MAD Primary Reserves (MW)	MAD Primary Reserve Shortage (MW)	Uncapped MAD Primary Reserve Clearing Price ($/MWh)	Capped MAD Primary Reserve Clearing Price ($/MWh)
24-Jan-26 05:40	2,780.5	2,659.4	121.1	$1,150.00	$1,150.00	2,780.5	2,659.4	121.1	$1,150.00	$1,150.00
09-Feb-26 07:15	2,749.0	2,703.6	45.4	$600.00	$600.00	2,749.0	2,749.0	0.0	$322.08	$322.08
09-Feb-26 07:20	2,749.0	2,058.0	691.0	$1,700.00	$1,275.00	2,749.0	2,058.0	691.0	$1,700.00	$1,700.00
09-Feb-26 07:25	2,749.0	1,965.9	783.2	$1,700.00	$1,275.00	2,749.0	1,965.9	783.2	$1,700.00	$1,700.00
09-Feb-26 07:30	2,750.5	1,998.3	752.2	$1,700.00	$1,275.00	2,750.5	1,998.3	752.2	$1,700.00	$1,700.00
09-Feb-26 07:35	2,752.0	2,740.5	11.6	$600.00	$600.00	2,752.0	2,752.0	0.0	$579.55	$579.55
01-Mar-26 19:30	2,693.5	2,497.5	196.0	$1,700.00	$1,275.00	2,693.5	2,497.5	196.0	$1,700.00	$1,700.00
01-Mar-26 19:35	2,698.0	2,380.5	317.5	$1,700.00	$1,275.00	2,698.0	2,380.5	317.5	$1,700.00	$1,700.00
12-Mar-26 19:05	2,765.5	2,688.2	77.4	$1,150.00	$1,150.00	2,765.5	2,688.2	77.4	$1,150.00	$1,150.00
12-Mar-26 19:10	2,767.0	2,195.2	571.8	$1,700.00	$1,275.00	2,767.0	2,195.2	571.8	$1,700.00	$1,700.00
13-Mar-26 07:10	2,779.0	2,764.1	15.0	$1,150.00	$1,150.00	2,779.0	2,764.1	15.0	$1,150.00	$1,150.00
13-Mar-26 07:15	2,780.5	1,917.4	863.1	$1,700.00	$1,275.00	2,780.5	1,917.4	863.1	$1,700.00	$1,700.00
13-Mar-26 07:20	2,779.0	1,829.5	949.5	$1,700.00	$1,275.00	2,779.0	1,829.5	949.5	$1,700.00	$1,700.00
13-Mar-26 07:25	2,779.0	2,399.5	379.5	$1,700.00	$1,275.00	2,779.0	2,399.5	379.5	$1,700.00	$1,700.00

149 For the full version, see Monitoring Analytics LLC, "Reserve Shortages," (May 14, 2026) <https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2026/IMM_Reserve_Shortages_20260514.xlsx>.

System Marginal Price Cap

Prior to PJM's implementation of the modified reserve markets on October 1, 2022, in the PJM real-time market, the SMP was capped at $3,750 per MWh. This cap was the sum of the Energy Offer Cap ($2,000 per MWh under defined conditions), the Synchronous Reserve Penalty Factor from the first step on the demand curve ($850 per MWh), the Primary Reserve Penalty Factor from the first step on the demand curve ($850 per MWh) and a threshold ($50 per MWh). The Operating Agreement stated that only two of the four reserve penalty factors may be applied.

In that prior implementation, if the SMP would otherwise exceed $3,750 per MWh, PJM solved the SCED optimization by progressively relaxing reserve requirement constraints until the SMP fell below the cap. For instance, if the original SMP was above $3,750, PJM would solve the SCED optimization by disabling the subzone (MAD) primary reserve requirement constraint. If the SMP from the relaxed SCED optimization was still above $3,750, PJM would solve the SCED optimization by disabling subzone (MAD) primary and synchronized reserve requirement constraints. If the relaxed SCED optimization was still above $3,750, PJM would solve the SCED optimization by disabling subzone (MAD) primary and synchronized reserve requirement constraints and the RTO primary reserve constraint.

Starting with PJM's implementation of the new Reserve Price Formation rules on October 1, 2022, in the PJM real-time market, the SMP has an administrative maximum price of $3,700 per MWh. Unlike the prior implementation, PJM's new cap does not include a $50 per MWh threshold and is not enforced by progressively relaxing reserve requirement constraints. PJM's new cap is an ex post administrative override of the SMP calculated in the pricing run (LPC). The SMP is not capped in the dispatch run (SCED). The congestion component of the LMP and the loss component of the LMP are not subject to this maximum price. The LMP at a pricing node could still exceed $3,700 per MWh. Unlike other administrative caps, such as the cap on the shadow price of a transmission constraint enforced through transmission penalty factor within the optimization, the SMP cap is not enforced within the optimization. When the SMP cap is enforced, the resulting LMPs are not consistent and do not accurately reflect the marginal cost of serving energy and reserves.

Table 3-91 shows the number of five minute intervals in the real-time market where the SMP was capped for each year since 2018. In the first three months of 2026, there were six five minute intervals in the real-time market in which the SMP was capped.

Table 3-91 Number of five minute intervals with capped SMP: 2018 through March 2026

Year	Number of Five Minute Intervals with Capped SMP
2018	0
2019	1
2020	1
2021	2
2022	51
2023	1
2024	0
2025	6
2026 (Jan - Mar)	3

The MMU recommends that PJM stop capping the system marginal price and instead limit the sum of violated reserve constraint shadow prices used in LPC to $1,700 per MWh.

Accuracy of Reserve Measurement

The definition of a shortage of synchronized and primary reserves is based on the measured and estimated levels of load, generation, interchange, demand response, and reserves from the real-time SCED software. The definition of such shortage also includes discretionary operator inputs to the ASO (Ancillary Service Optimizer) or RT SCED software, such as operator load bias. For shortage pricing to be accurate, there must be accurate measurement of real-time reserves. That does not appear to be the case at present in PJM, but there does not appear to be any reason that PJM cannot accurately measure reserves. Without accurate measurement of reserves on a minute by minute basis, system operators cannot know with certainty that there is a shortage condition and a reliable trigger for five minute shortage pricing does not exist.

The benefits of five minute shortage pricing are based on the assumption that a shortage can be precisely and transparently defined.[150] PJM cannot accurately measure or price reserves due to the inaccuracy of its generator models. PJM's commitment and dispatch models rely on generator data to properly commit and dispatch generators. Generator data includes offers and parameters. When the models do not properly account for the different generator characteristics, both PJM dispatchers and generators have to make simplifications and assumptions using the tools available. Most of these actions taken by generators and by PJM dispatchers are not transparent. PJM manuals do not provide clarity regarding what actions generators can take when the PJM models and tools do not reflect their operational characteristics and PJM manuals do not provide sufficient clarity regarding the actions PJM dispatchers can take when generators do not follow dispatch.

In the energy and reserve markets, the actions that both generators and PJM dispatchers take have a direct impact on the amount of supply available for energy and reserves and the prices for energy and reserves. These flaws in PJM's models do not allow PJM to accurately calculate the amount of reserves available. PJM does not accurately model discontinuities in generator ramp rates, such as duct burners on combined cycle plants. PJM's generator models do not account for the complexities that may result in generators underperforming their submitted ramp rates. PJM should address these complexities through generator modeling improvements. PJM also fails to accurately model unit starts. The market software does not account for the energy output a resource produces prior to reaching its economic minimum output level, during its soak time.

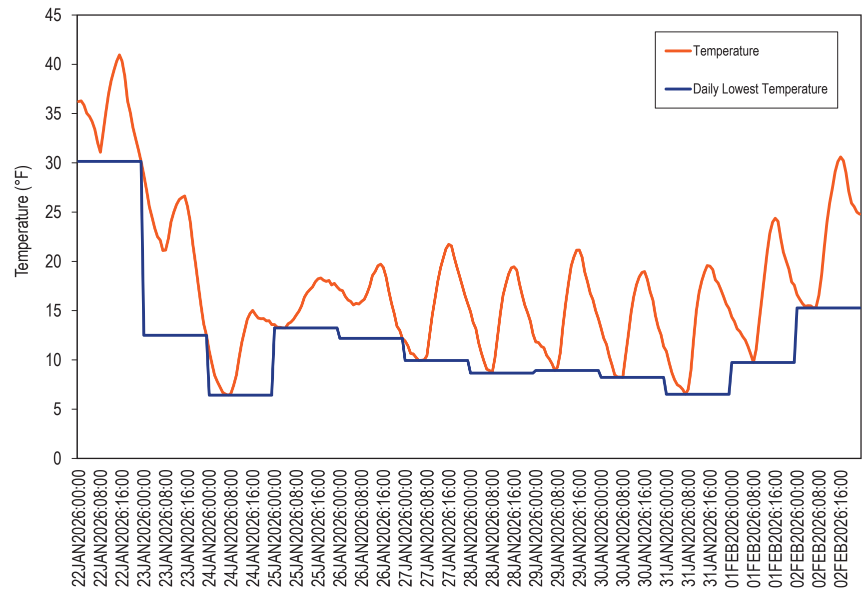
Generators can deselect themselves from providing reserves by communicating to PJM that their resources will not follow the dispatch signal (e.g. offer fixed gen or operate as nondispatchable). These actions allow generators to withhold reserves and result in a violation of the reserve must offer requirement when the resources operate below their economic maximum.

150 See Comments of the Independent Market Monitor for PJM, Docket No. RM15-24-000 (December 1, 2015) at 9.

Winter Storm Fern

Winter Storm Fern affected the PJM region from January 22 through January 30, 2026. The storm brought significant snow and ice precipitation from Friday, January 23 through Monday January 26, 2026. Cold temperatures persisted through the following week (January 27 through January 30).[151] Figure 3-57 shows the PJM load weighted average temperatures from January 22 through February 2, 2026.

Figure 3-57 PJM Load Weighted Average Temperatures: January 22 through February 2, 2026



In preparation for the weather event, PJM declared several operating procedures including an Energy Emergency Alert 1 (EEA1) on January 27. See Figure 3-51 for the list of operating procedures declared by PJM during Winter Storm Fern and their duration.

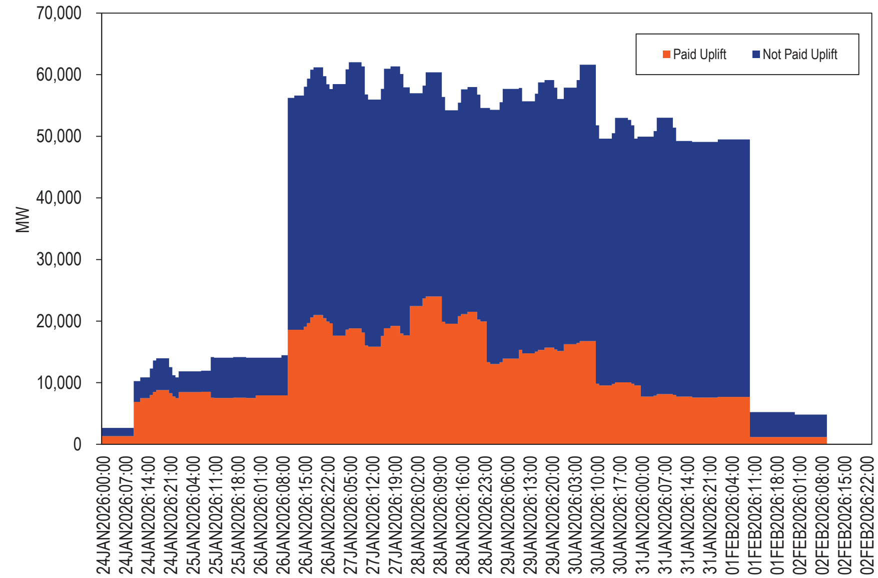
151 See "January Cold Weather Operations," Operating Committee (February 5, 2026). <https://www.pjm.com/-/media/DotCom/committees-groups/committees/oc/2026/20260205/20260205-item-03---cold-weather-update---revised.pdf>.

On Thursday, January 22, PJM peak load forecast for the following week was 147,347 MWh (on Tuesday 27), higher than PJM's all time winter peak load of 143,714 MWh on January 22, 2025. The actual highest load was 139,047 MWh on January 29, 2026. PJM stated that warmer actual temperatures and building closures were reasons for the over forecast. The 10 day period between January 24 and February 2, 2026, had the highest average load in PJM's history at 125,573 MWh (5.6 percent higher than the previous 10 day period between June 22 through July 1, 2025).

For this event, PJM continued its approach of scheduling units in advance of the Day-Ahead Energy Market. PJM began this approach after Winter Storm Elliott in December 2022 to address supply uncertainty resulting from performance risk. The performance risk is attributable to units that cannot operate and/or start reliably in cold weather, based on data collected from the generators by PJM, and/or natural gas fired units that face fuel procurement uncertainty when the fuel is not purchased during the active trading window. This issue is especially critical during weekends since the trading window occurs on Friday for the next three days (known as the weekend package).

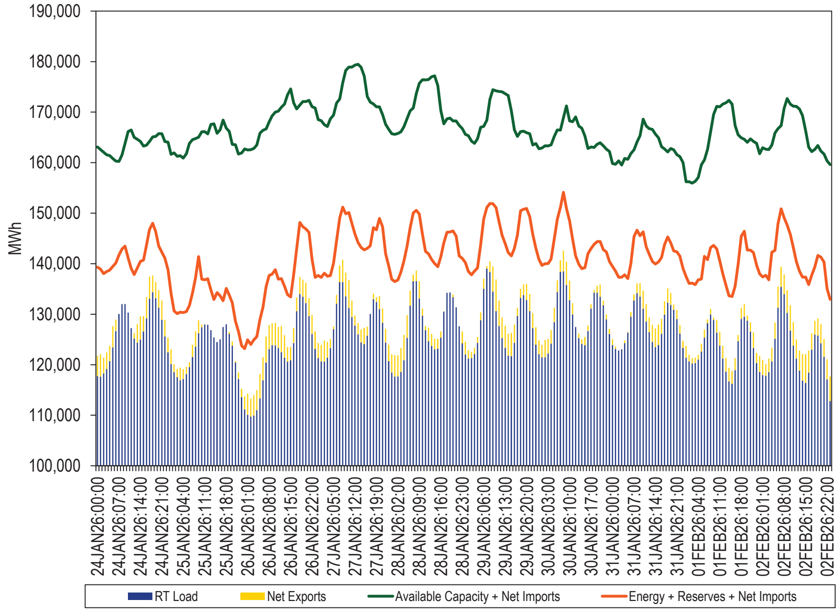
Figure 3-58 shows the economic maximum of all units committed in advance of the Day-Ahead Energy Market. Figure 3-58 separates the MW between units that were paid uplift because their operation was uneconomic and units that did not receive uplift because either their operation was economic or self scheduled.

Figure 3-58 Economic Maximum (MW) of Units Committed in Advance of the Day-Ahead Energy Market during Winter Storm Fern



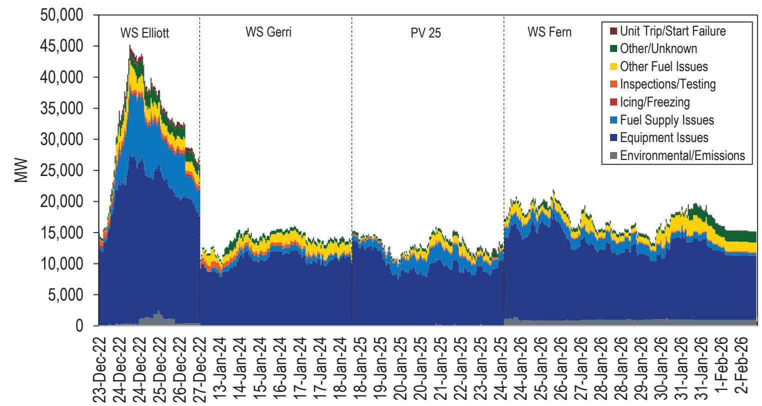
The impact of the advance commitment is shown in Figure 3-59. Figure 3-59 shows the available capacity (green line) and the energy plus reserves that the generation resources provided (orange line). The difference between the green and the orange lines are the MW not being used (headroom available) to provide either energy or reserves. At its lowest point the amount of headroom available was 14,792 MW. This is a reflection of the improved performance from generating units resulting mainly from PJM's advanced commitment approach. Figure 3-59 also show the load and exports in the blue and yellow bars. The difference between the red line and the sum of the blue and yellow bars are the reserve MW (synchronized, primary or 30 minute reserves).

Figure 3-59 Supply and Demand during Winter Storm Fern



The improved performance incorporated a reduction in outages. Figure 3-60 shows the outages during the last three significant winter events and its comparison with Winter Storm Elliott (2022). Outages during Winter Storm Gerri (2024), Polar Vortex 2025 and Winter Storm Fern (2026) were much lower than the outages during Winter Storm Elliott. Fuel related outages, in particular, were significantly lower in the last three events than in Winter Storm Elliott. This demonstrates the results of PJM's implementation of advanced commitment in preparation for the last three events but not for Winter Storm Elliott.

Figure 3-60 Outages during the last three significant winter events and Winter Storm Fern



The uplift associated with Winter Storm Fern was an expected outcome of conservative operations and a preferred result to the penalties that resulted from Winter Storm Elliott. This uplift is part of the way that PJM markets work and was the result of PJM's successful conservative operations approach to dealing with cold weather risks. The market results of PJM's actions in preparation for and during Winter Storm Gerri, Polar Vortex 2025 and Winter Storm Fern were better than the market results of PJM's actions during Winter Storm Elliott. Nonetheless, improvements are needed to make the advance commitment process more predictable and transparent and formalized, and made as market based as possible, in order to ensure that uplift is at an efficient and effective level.

Competitive Assessment

Market Structure

Market Concentration

The Herfindahl-Hirschman Index (HHI) concentration ratio is the sum of the squares of the market shares of all firms in a market. Hourly PJM energy market HHIs are based on the shares of the real-time energy output of generators, adjusted for scheduled imports. Hourly HHIs for the baseload, intermediate and peaking segments of generation supply are based on hourly energy market shares, unadjusted for imports.

The HHI is not a definitive measure of structural market power. It is possible to have pivotal suppliers 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 both local and aggregate structural market power than the HHI.

The HHI may not accurately capture market power issues in situations where, for example, there is moderate concentration in all on line resources but there is a high level of concentration in resources needed to meet increases in load. A pivotal supplier test is required to accurately measure the ability of incremental resources to exercise market power.

FERC's Merger Policy Statement defines levels of concentration by HHI level. The market is unconcentrated if the market HHI is below 1000, the HHI if there were 10 firms with equal market shares. The market is moderately concentrated if the market HHI is from 1000 to 1800. The market is highly concentrated if the market HHI is greater than 1800, the HHI if there were between five and six firms with equal market shares.[152]

When transmission constraints exist, local markets are created in which ownership is typically significantly more concentrated than the overall energy market. PJM offer capping rules that limit the exercise of local market power were generally effective in preventing the exercise of market power in the first nine months of 2025, although there are issues with the application of market power mitigation for resources whose owners fail the TPS test that permit local market power to be exercised even when PJM's flawed market power mitigation rules are applied. These issues include the lack of a method for consistently determining the cheaper of the cost and price schedules and the lack of rules requiring that cost-based offers equal short run marginal costs.

152 See *Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement, 77* FERC ¶ 61,263 *mimeo* at 80 (1996).

PJM HHI Results

Hourly HHIs indicate that by FERC standards, the PJM energy market in the first three months of 2026 was unconcentrated on average (Table 3-92).[153] The fact that the average HHI and the maximum hourly HHI are in the unconcentrated range does not mean that the aggregate market was competitive in all hours. It is possible to have pivotal suppliers in the aggregate market even when the HHI level does not indicate a highly concentrated market structure. Given the low responsiveness of consumers to prices (inelastic demand), it is possible to have high markup even when HHI is low. It is possible to have an exercise of market power even when the HHI level does not indicate a highly concentrated market structure.

Table 3-92 Real-time hourly aggregate energy market HHI: January through March, 2025 and 2026

HHI Statistic	Hourly Market HHI (Jan-Mar 2025)	Hourly Market HHI (Jan-Mar 2026)
Average	695	753
Minimum	577	621
Maximum	850	954
Highest market share (One hour)	22.5%	22.8%
Average of the highest hourly market share	16.9%	18.5%
# Hours	2,159	2,159
# Hours HHI > 1800	0	0
% Hours HHI > 1800	0%	0%

Table 3-93 includes HHI values by supply curve segment, including base, intermediate and peaking plants in the first three months of 2025 and 2026. On average, ownership in the baseload segment was unconcentrated, in the intermediate segment was moderately concentrated, and in the peaking segment was highly concentrated.[154]

153 The HHI calculations use actual real time settled generation data for each unit in PJM. Each unit's output is assigned to the owner that is responsible for offering the unit in the energy market.

154 A unit is classified as base load if it runs for 50 percent of hours or more, as intermediate if it runs for less than 50 percent but greater than or equal to 10 percent of hours, and as peak if it runs for less than 10 percent of hours.

Table 3-93 Real-time hourly energy market HHI by generation segment: January through March, 2025 and 2026

	Jan-Mar 2025			Jan-Mar 2026		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	632	747	880	722	830	1090
Intermediate	483	1624	9249	392	1141	7327
Peak	1008	6397	10000	899	5930	10000

Figure 3-61 shows the total installed capacity (ICAP) MW of units in the baseload, intermediate and peaking segments by fuel source in the first three months of 2026.[155]

Figure 3-61 Real-time ICAP distribution by fuel and segment: January through March, 2026[156]

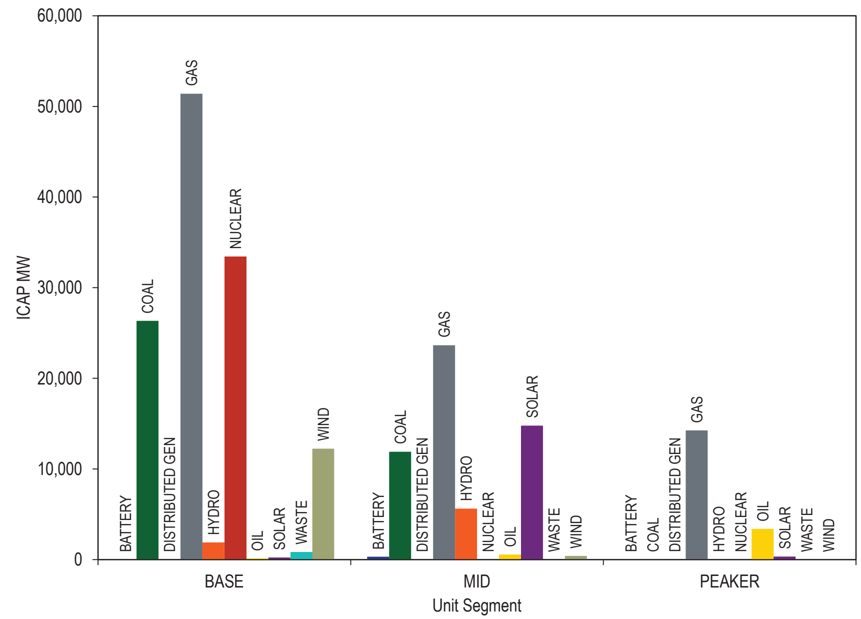


Figure 3-62 shows the ICAP of coal fired and gas fired units in PJM that are classified as baseload, intermediate and peaking in the first three months of 2014 through 2026. Figure 3-62 shows that the total ICAP of coal fired units in PJM classified as baseload generally decreased from 2014 through 2026, while the total ICAP of gas fired units in PJM classified as baseload generally increased.

155 The installed capacity (ICAP) used for wind and solar units here is their nameplate capacity in MW. In PJM's Capacity Market, the UCAP value of wind and solar units is derated from the ICAP value using ELCC.

156 The units classified as Distributed Gen are buses within Electric Distribution Companies (EDCs) that are modeled as generation buses to accurately reflect net energy injections from distribution level load buses. The modeling change was the outcome of the Net Energy Metering Task Force stakeholder group in July, 2012. See PJM. "Net Energy Metering Senior Task Force (NEMSTF) 1st Read - Final Report and Proposed Manual Revisions," (June 28, 2012).

Figure 3-62 Real-time annual gas and coal unit segment classification: January through March, 2014 through 2026

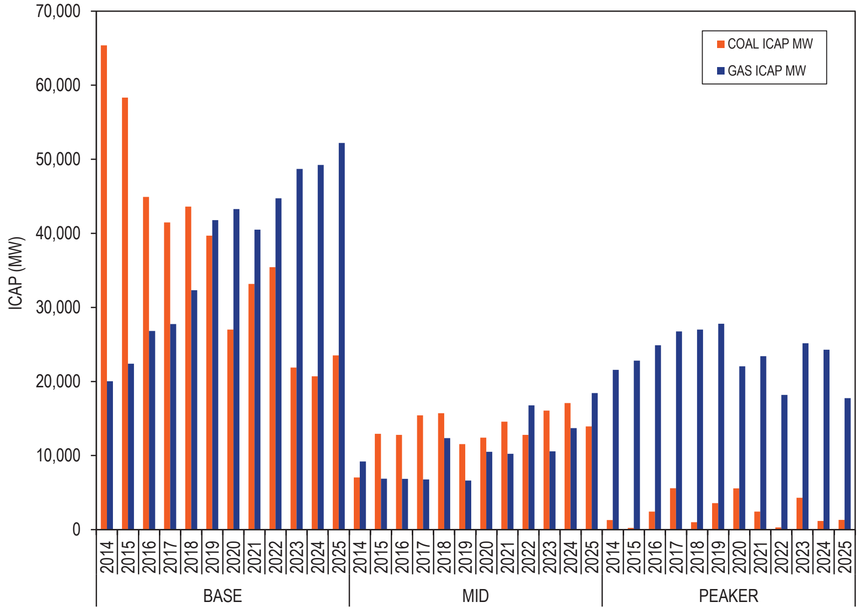
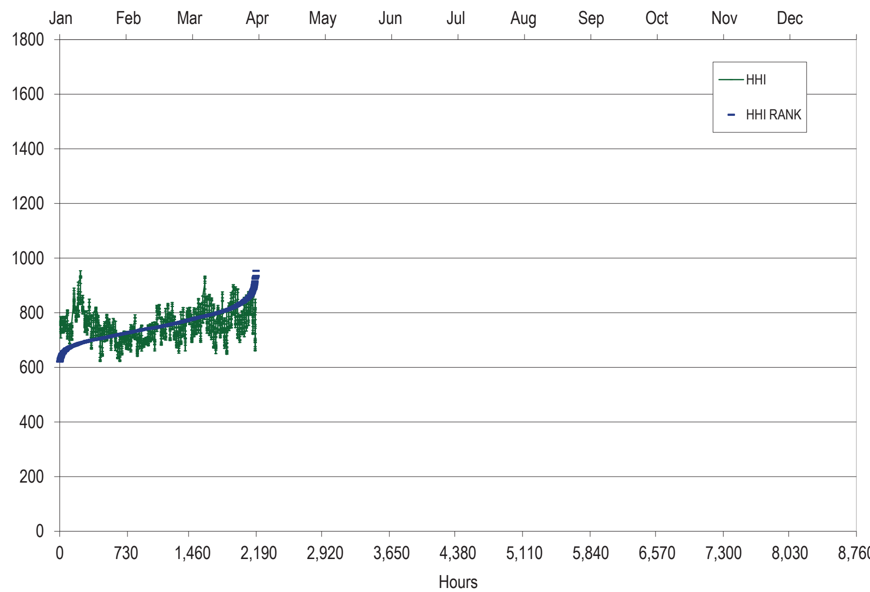


Figure 3-63 presents the hourly HHI values in chronological order and an HHI duration curve for the first three months of 2026. The HHI duration curve shows the number of hours that HHI was at or below a given value in the first three months of 2026.

Figure 3-63 Real-time hourly aggregate energy market HHI: January through March, 2026



Market Based Rates

Participation by generators in the PJM market using offers that exceed costs requires market based rate authority approved by FERC.[157] FERC reviews the market based rate authority of PJM market sellers of generation on a triennial schedule to ensure that market sellers do not have market power or that market power is appropriately mitigated. The entire PJM region is included in the Northeast Region for purposes of the triennial review schedule. Triennial

157 See *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, FERC Stats. & Regs. ¶ 31,252 (2007), *clarified*, 121 FERC ¶ 61,260 (2007), *order on reh'g*, Order No. 697-A, 123 FERC ¶ 61,055, *clarified*, 124 FERC ¶ 61,055, *order on reh'g*, Order No. 697-B, 125 FERC ¶ 61,326 (2008), *order on reh'g*, Order No. 697-C, 127 FERC ¶ 61,284 (2009), *order on reh'g*, Order No. 697-D, 130 FERC ¶ 61,206 (2010), *aff'd sub nom.* Mont. Consumer Counsel v. FERC, 659 F.3d 910 (9th Cir. 2011).

filings by utilities with market based rates authorizations must include a market power analysis or a statement that market power has been adequately mitigated under the PJM market rules. Based on Order No. 861, sellers may, in lieu of filing a market power analysis, rely on a rebuttable presumption that market monitoring and market power mitigation are sufficient to ensure competitive market outcomes.[158]

The rules specify a separate filing schedule for transmission owning utilities and nontransmission owning utilities. The rules define a study period for market power analyses including four complete seasons. A study runs from December of one year through November of the following year (i.e., the period includes one complete winter season rather than splitting winter as a calendar year approach would). The study period is not relevant for companies that choose the rebuttable presumption option.

The most recent triennial review filings for nontransmission owning utilities in PJM were filed in June 2023. The applicable study period for the June 2023 filings, ran from December 1, 2020, to November 30, 2021. Triennial review filings for transmission owners in PJM were filed in December 2022. The applicable study period for the December 2022 filings ran from December 1, 2020, to November 30, 2021.

The MMU has recommended since 2015 that changes to the offer capping process for the energy market are needed to ensure effective market power mitigation of units that fail the TPS test. With these results and the supporting evidence, the MMU challenged the rebuttable presumption of sufficient market power mitigation for the June 2020, December 2022, and June 2023 triennial review filings by generating unit owners in PJM. The MMU explained the issues with PJM's offer schedule selection process that allow generators to avoid energy market power mitigation as well as the then overstated capacity market seller offer cap. The MMU recommended that generators not be allowed to rely on PJM's implementation of market power mitigation rules to ensure competitive market outcomes until improvements are made to the offer capping processes in the energy and capacity markets so that suppliers cannot exercise market power.[159] In 2021, FERC issued orders requiring review of the adequacy of the market power mitigation rules and their implementation in the capacity and energy markets.[160] [161] FERC addressed the capacity market Market Seller Offer Cap later in 2021.[162] [163] FERC did not address the energy market power mitigation issues.

158 *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 No. 861").

Merger Reviews

FERC reviews proposed dispositions, consolidations, acquisitions, and changes in control of jurisdictional generating units and transmission facilities under section 203 of the Federal Power Act to determine whether such transactions are "consistent with the public interest."[164] [165]

FERC applies tests set forth in the 1996 Merger Policy Statement, written prior to the introduction of competitive markets in PJM.[166] [167] The 1996 Merger Policy Statement provides for review of jurisdictional transactions based on "(1) the effect on competition; (2) the effect on rates; and (3) the effect on regulation." FERC adopted the 1992 Department of Justice Guidelines and the Federal Trade Commission Horizontal Merger Guideline (1992 Guidelines) to evaluate the effect on competition. FERC continues to use the 1992 Guidelines even after the Department of Justice modified its guidelines in 2010.[168] Following the 1992 Guidelines, FERC applies a five step framework, which includes: defining the market; analyzing market concentration; analyzing mitigative effects of new entry; assessing efficiency gains; and assessing viability of the parties without a merger. FERC also evaluates the results of a Competitive Analysis Screen measuring HHI changes for markets defined by transmission

159 See Protest of the Independent Market Monitor for PJM, Docket No. ER10-1556 et al. (August 28, 2020); Comments of the Independent Market Monitor for PJM, Docket No. ER10-1618-018 et al. (February 13, 2023); Comments of the Independent Market Monitor for PJM, Docket No. ER23-9-000 et al. (August 28, 2023).
160 See 175 FERC ¶ 61,231 (2021).
161 See 174 FERC ¶ 61,212 (2021).
162 See 176 FERC ¶ 61,137 (2021), *reh'g denied*, 178 FERC ¶ 61,121 (2022), *appeal denied*, Vistra Corp. v. FERC, 80 F.4th 302 (2023).
163 *See* Monitoring Analytics, L.L.C., *2021 Annual State of the Market Report for PJM*, Vol. 2, Section 5: Capacity Market at 311-312.
164 18 U.S.C. § 824b.
165 In February 2019, in response to 2017 amendments to Section 203 of the Federal Power Act, the Commission issued Order No. 855, implementing a $10,000,000 minimum value for transactions requiring the Commission's review. See 166 FERC ¶ 61,120 (2019)
166 See Order No. 592, FERC Stats. & Regs. ¶ 31,044 (1996) (1996 Merger Policy Statement), *reconsideration denied*, Order No. 592-A, 79 FERC ¶ 61,321 (1997). See also FPA Section 203 Supplemental Policy Statement, FERC Stats. & Regs. ¶ 31,253 (2007), *order on clarification and reconsideration*, 122 FERC ¶ 61,157 (2008).
167 FERC has an open but inactive docket where the guidelines are under review. See 156 FERC ¶ 61,214 (2016); FERC Docket No. RM16-21-000.
168 See 138 FERC ¶ 61,109 (2012).

zones. This approach does not take into account the effect of a transaction on actual PJM LMPs or capacity market prices.

The MMU reviews proposed mergers and acquisitions based on analysis of the impact of the merger or acquisition on market power given actual PJM market conditions under the current competitive market design. The analysis includes use of the three pivotal supplier test results in the real-time energy market. The MMU's review ensures that mergers are evaluated based on their impact on local market power in the PJM energy market using actual observed market conditions, actual binding constraints and actual congestion results. This is in contrast to the typical merger filing that uses predefined local markets based on historical conditions that no longer exist rather than the actual local markets based on current and potential market conditions. The MMU files comments with FERC including such analyses.[169] The MMU has proposed that FERC adopt this approach when evaluating mergers in PJM.[170] Subsequent to the MMU's arguments about local markets, FERC has required further analysis of local markets from applicants at the transmission zone level.[171] FERC has considered the MMU's analysis in reviewing mergers but continues to apply an analysis that does not accurately account for locational market power in an LMP market.[172]

Neither the MMU's analysis nor the FERC defined analysis is an adequate replacement for effective market power mitigation, because system conditions are dynamic and any owner can become pivotal at any time. FERC routinely approves mergers and acquisitions and grants Market Based Rates authority to PJM market sellers despite known issues in the market power mitigation process that allow market sellers to exercise their market power. For this reason, the MMU recommends that FERC approve mergers and acquisitions conditioned on behavioral commitments by the market sellers that prevent the exercise of market power.

The MMU has also reached agreements to mitigate market power in cases where market power concerns have been identified.[173] [174] Such mitigation is designed to mitigate behavior over the long term, in addition to or instead of structural mitigation in the form of asset divestiture requirements.

The MMU also reviews transactions that involve ownership changes of PJM generation resources that are submitted to the Commission pursuant to section 203 of the Federal Power Act. Table 3-94 shows ownership changes in the PJM market that involved entire resources that were completed in the first three months of 2026, as reported to the Commission. Table 3-95 shows transactions that involved transfers of partial unit ownership that were completed in the first three months of 2026, as reported to the Commission.[175] [176]

169 See, e.g., Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-141-000 (Nov. 10, 2014); Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-96-000 (July 21, 2014) Comments of the Independent Market Monitor for PJM, FERC Docket No. EC11-83-000 (July 21, 2011); Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-14 (Dec. 9, 2013); Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-112-000 (Sept. 15, 2014); Comments of the Independent Market Monitor for PJM, FERC Docket No. EC20-49 (June 1, 2020).

170 See Comments of the Independent Market Monitor for PJM, Docket No. RM16-21 (Dec. 12, 2016).

171 See, for example, Darby Power, LLC, et al., Response to Second Deficiency Letter, Request for Confidential Treatment, Request for Shortened Comment Period, and Request for Expeditious Action, Docket No. EC24-125 (March 27, 2025).

172 See *Dynegy Inc., et al.*, 150 FERC ¶ 61, 231 (2015); *Exelon Corporation, Constellation Energy Group, Inc.*, 138 FERC ¶ 61,167 (2012); *NRG Energy Holdings, Inc., Edison Mission Energy*, 146 FERC ¶ 61,196 (2014); *see also Analysis of Horizontal Market Power under the Federal Power Act*, 138 FERC ¶ 61,109 (2012).

173 See 138 FERC ¶ 61,167 at P 19 (2012). The Maryland PSC accepted without condition or modification the settlement between Constellation and the MMU at the February 1, 2022, hearing in Case No. 9271. See *In the Matter of the Merger of Exelon Corporation and Constellation Energy Group, Inc.*, Order No. 90084, Order Approving 2021 Settlement Agreement and Denying Request to Require Exelon to Remain In PJM, Case No. 9271 (February 22, 2022). By its terms, the settlement became effective on February 1, 2022.

174 See 192 FERC ¶ 61,074 at 169. FERC accepted Constellation's behavioral commitments agreed to with the MMU and conditioned its approval of the acquisition of Calpine on those commitments.

175 The transaction completion date is based on the notices of consummation submitted to the Commission.

176 For transfers of partial unit ownership, total MW reflects the entire capacity of the transferred asset or assets, as reported to the Commission.

Table 3-94 Completed transfers of entire resources: January through March, 2026

Generator or Generation Owner Name	Total MW	From	To	Transaction Completion Date	Docket
Calpine Corporation	5,341.0	Bridgepoint Group PLC	Constellation Energy Group	January 7, 2026	EC25-43
Eagle Creek Racine Hydro, LLC and Lake Lynn Generation, LLC	98.6	Ontario Power Generation Inc.	Apollo Global Management, Inc	January 9, 2026	EC26-8
Lightning Power, LLC (Armstrong Power, LLC; Aurora Generation, LLC; Chambersburg Energy, LLC; Doswell Limited Partnership; Gans Energy, LLC; Helix Ironwood, LLC; LSP University Park, LLC; Riverside Genering Company, L.L.LC; Rockford Power, LLC; Rockford Power II, LLC; Springdale Energy, LLC; Troy Energy, LLC; University Park Energy, LLC)	7,821.0	LS Power Group	NRG Energy, Inc.	January 30, 2026	EC25-102
Elwood Power Station Units 5-7	150.0	J-POWER USA Generation, L.P.	Dairyland Power Cooperative	March 6, 2026	EC25-127
Hill Top Energy Center, LLC	623.0	Ardian Holding s.a.s.	Blackstone Inc.	March 26, 2026	EC25-148
Conetoe II Solar, LLC	80.0	Brookfield Asset Management Ltd.	BlackRock, Inc.	March 30, 2026	EC26-13

Table 3-95 Completed transfers of partial ownership of resources: January through March, 2026

Generator or Generation Owner Name	Total MW	Percent	From	To	Transaction Completion Date	Docket
Clinton Solar LLC and Montpelier Solar, LLC	99.0	50.0%	TotalEnergies SE	KKR & Co. Inc.	January 26, 2026	EC26-12
Heritage Power, LLC (Blossburg Power, LLC; Brunot Island Power, LLC; Gilber Power, LLC; Hunterstown Power, LLC; Mountain Power, LLC; New Castle Power, LLC; Niles Power, LLC; Lortanna Power, LLC; Portland Power, LLC; Sayreville Power, LLC; Shawnee Power, LLC; Shawville Power, LLC; Titus Power, LLC; Tolna Power, LLC; Warren Generation, LLC)	2,283.8	>10%	Avenue Capital Group	Hudson Bay Capital Management LP	January 21, 2026	EC26-18
Carroll County Energy LLC	832.3	31.6%	JERA, Co., Inc (20.00%) and San Jacinto Carroll Holdings LLC (11.64%)	Strategic Value Partners, LLC	February 12, 2026	EC25-152
Carroll County Energy LLC	832.3	10.6%	Ullico Infrastructure Master Fund, L.P.	ArcLight Capital Partners, LLC	February 6, 2026	EC25-151
Advanced Power US Holdings Inc. (Carroll County Energy LLC [17.76%]) and South Field Energy LLC [15.55%])	1,905.0	100% of controlling entity	Advanced Power AG	ArcLight Capital Partners, LLC	February 12, 2026	EC25-123*
Alpha Generation, LLC (Clean Energy Future - Lordstown, LLC; Parkway Generation Keys Energy Center LLC; Parkway Generation Operating LLC;Parkway Generation Sewaren Urban Renewal Entity LLC)	5,688.0	>10%	ArcLight Capital Partners, LLC	Canada Pension Plan Investment Board	March 9, 2025	EC26-21

Aggregate Market Pivotal Supplier Results

Notwithstanding the HHI level, a supplier may have the ability to raise energy market prices. If reliably meeting the PJM system load requires energy from a single supplier, that supplier is singly pivotal and has monopoly market power in the aggregate energy market. If reliably meeting the PJM system load requires energy from a small number of suppliers, those suppliers are jointly pivotal and have oligopoly market power in the aggregate energy market. 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 identification of jointly pivotal suppliers as a source of market power does not require an assumption that the suppliers collude. There are multiple mechanisms that would permit the exercise of market power when there are limited suppliers providing relief to a constraint. FERC Order No. 697 also recognizes this explicitly in the discussion of HHI and pivotal suppliers.[177] FERC's definition of highly concentrated markets, based on an HHI greater than 1800, includes between five and six owners with equal market shares.

177 Order No. 697, FERC Stats. & Regs. ¶ 31,252 at PP 104–117.

The current market power mitigation rules for the PJM energy market rely on the assumption that the aggregate market includes sufficient competing sellers to ensure competitive market outcomes. With sufficient competition, any attempt to economically or physically withhold generation would not result in higher market prices, because another supplier would replace the generation at a similar price. 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 generally correct, as demonstrated by these results. There are pivotal suppliers in the aggregate energy market.

The existing market power mitigation measures do not address aggregate market power.[178] Aggregate market power should be mitigated in the PJM Day-Ahead and Real-Time Markets when the three pivotal supplier test for the aggregate market is failed.

Day-Ahead Aggregate Energy Market Pivotal Suppliers

To assess the number of pivotal suppliers in the aggregate day-ahead energy market, the MMU determined, for each supplier, the MW available for economic commitment that were already running or were available to start between the close of the day-ahead energy market and the peak load hour of the operating day. The available supply is defined as MW offered at a price less than 150 percent of the applicable LMP because supply available at higher prices is not competing to meet the demand for energy. Generating units, import transactions, economic demand response, and INCs, are included for each supplier.[179] Demand is the total MW required by PJM to meet physical load, cleared load bids, export transactions, and DECs, which is the total cleared supply for the peak hour of the day. A supplier is pivotal if PJM would require some portion of the supplier's available economic capacity in the peak hour of the operating day in order to meet demand. Suppliers are jointly pivotal if PJM would require some portion of the joint suppliers' available economic capacity in the peak hour of the operating day in order to meet demand.

Based on this method, Table 3-96 shows the number of days in 2025 and the first three months of 2026 with one or multiple singly pivotal suppliers, labelled as one pivotal supplier, with two or more suppliers that were each jointly pivotal with one other supplier, labelled as two pivotal suppliers, and with three or more suppliers that were each jointly pivotal with two other suppliers, labelled as three pivotal suppliers. For 2025, there were three pivotal suppliers for 95.3 percent of days. For the first three months of 2026, there were three pivotal suppliers for 90.0 percent of days.

Table 3-96 Number of days with day-ahead aggregate pivotal suppliers: January 2025 through March 2026

Year	Month	Days with One Pivotal Suppliers	Percent of Days with One Pivotal	Days with Two Pivotal Suppliers	Percent of Days with Two Pivotal	Days with Three Pivotal Suppliers	Percent of Days with Three Pivotal
2025	Jan	0	0.0%	10	32.3%	28	90.3%
2025	Feb	0	0.0%	15	53.6%	26	92.9%
2025	Mar	0	0.0%	3	9.7%	25	80.6%
2025	Apr	0	0.0%	9	30.0%	27	90.0%
2025	May	0	0.0%	18	58.1%	30	96.8%
2025	Jun	4	13.3%	26	86.7%	30	100.0%
2025	Jul	9	29.0%	31	100.0%	31	100.0%
2025	Aug	0	0.0%	29	93.5%	31	100.0%
2025	Sep	0	0.0%	21	70.0%	29	96.7%
2025	Oct	2	6.5%	11	35.5%	30	96.8%
2025	Nov	0	0.0%	10	33.3%	30	100.0%
2025	Dec	0	0.0%	19	61.3%	31	100.0%
2025	Annual	15	4.1%	202	55.3%	348	95.3%
2026	Jan	2	6.5%	16	51.6%	28	90.3%
2026	Feb	0	0.0%	12	42.9%	28	100.0%
2026	Mar	0	0.0%	10	32.3%	25	80.6%
2026	Jan-Mar	2	2.2%	38	42.2%	81	90.0%

Figure 3-64 shows the number of days in the first three months of 2025 and 2026 with one pivotal supplier, two jointly pivotal suppliers, and three jointly pivotal suppliers in the day-ahead aggregate energy market by daily peak load level. It shows that market power, measured by the average number of suppliers that are pivotal, increases with daily peak load. The average number

178 One supplier, Exelon Generating Company, LLC, is partially mitigated for aggregate market power through a settlement agreement with the MMU filed December 30, 2021, and approved by the Maryland Public Service Commission as a condition of its merger. *In the Matter of the Merger of Exelon Corporation and Constellation Energy Group, Inc.*, Order No. 90084, Maryland PSC Case No. 9271 (February 22, 2022). Order No. 90084 replaces the original 10 year settlement in this case included as a condition in Order No. 84698, issued February 17, 2012, which approved the merger between Exelon and Constellation Energy Group.

179 Generation, imports, demand response, and virtual transactions are assigned to parent companies based on the ultimate parent company owner of their PJM account.

of suppliers in the first three months of 2026 that were one of three pivotal suppliers (yellow line) was 54.2 on the 18 days with a peak load between 90 and 100 GW (dark gray bar) and was 184.0 suppliers on the day with a peak load between 140 and 150 GW. The number of pivotal suppliers generally increases with load.

The frequency of daily aggregate pivotal suppliers in the day-ahead market increased in in the first three months of 2026 compared to the first three months of 2025 at high levels of daily peak load shown in Figure 3-64. The overall frequency of pivotal suppliers rose with an increase in the frequency of days with daily peak load above 130 GW. In the first three months of both 2025 and 2026, all days with peak load over 130 GW had day-ahead aggregate market pivotal suppliers. There were 12 days with a daily peak load over 130 GW in the first three months of 2026, compared to 5 in the first three months of 2025.

Figure 3-64 Average number of pivotal suppliers in the day-ahead energy market by daily peak load level: January through March, 2025 and 2026

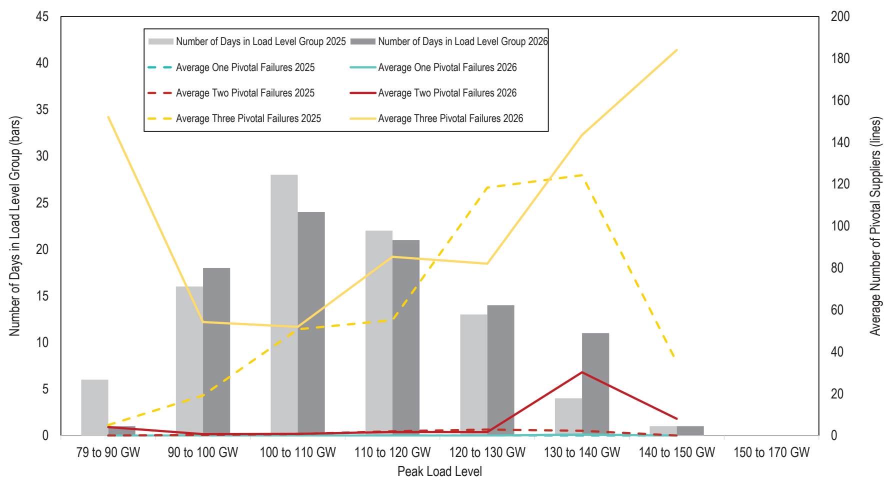


Table 3-97 provides the frequency with which each of the top 10 pivotal suppliers was singly or jointly pivotal for the day-ahead aggregate energy market in the first three months of 2026. All of the top 10 suppliers were one of three pivotal suppliers on at least 51 days in the first three months of 2026 (56.7 percent of the days). Two suppliers were singly pivotal on 2 days.

Table 3-97 Day-ahead market pivotal supplier frequency: January through March, 2026

Pivotal Supplier Rank	Days Singly Pivotal	Percent of Days	Days Jointly Pivotal with One Other Supplier	Percent of Days	Days Jointly Pivotal with Two Other Suppliers	Percent of Days
1	2	2.2%	38	42.2%	81	90.0%
2	2	2.2%	34	37.8%	81	90.0%
3	1	1.1%	36	40.0%	81	90.0%
4	0	0.0%	10	11.1%	66	73.3%
5	0	0.0%	8	8.9%	75	83.3%
6	0	0.0%	8	8.9%	71	78.9%
7	0	0.0%	7	7.8%	77	85.6%
8	0	0.0%	5	5.6%	74	82.2%
9	0	0.0%	3	3.3%	51	56.7%
10	0	0.0%	2	2.2%	62	68.9%

Market Behavior

Local Market Power

In the PJM energy market, market power mitigation rules currently apply only for local market power. Local market power exists when transmission constraints or reliability issues create local markets that are structurally noncompetitive.[180] If the owners of the units required to solve the constraint or reliability issue are pivotal or jointly pivotal, they have the ability to set the price. Absent market power mitigation, unit owners that submit noncompetitive offers, or offers with inflexible operating parameters, could exercise market power. This could result in LMPs being set at higher than competitive levels, or could result in noncompetitive uplift payments.

180 OA Schedule 1, Section 6.4.1.

The three pivotal supplier (TPS) test is the test for local market power in the energy market.[181] If the TPS test is failed, market power mitigation is applied by offer capping the resources of the owners who have been identified as having local market power. Offer capping is designed to set offers at competitive levels. Competitive offers are defined to be cost-based energy offers. In the PJM energy market, units are required to submit cost-based energy offers, defined by fuel cost policies, and have the option to submit market-based offers, also called price-based offers. Units are committed and dispatched on price-based offers, if offered, as the default offer. When a unit that submits both cost-based and price-based offers is mitigated to its cost-based offer by PJM, it is considered offer capped. A unit that submits only cost-based offers, or that requests PJM to dispatch it on its cost-based offer, is not considered offer capped.

Local market power mitigation is implemented in both the day-ahead and real-time energy markets. However, the implementation of the TPS test and offer capping differ in the day-ahead and real-time energy markets.

TPS Test Statistics for Local Market Power

The TPS test in the energy market defines whether three suppliers are jointly pivotal in a defined local market. The TPS test is applied when the system solution indicates that a transmission constraint is binding or requires the commitment of additional resources. The TPS test result for a constraint for a specific interval indicates whether a supplier failed or passed the test for that constraint for that interval. A failed test indicates that the resource owner has structural market power.

A metric to describe the number of local markets created by transmission constraints and the applicability of the TPS test is the number of hours that each transmission constraint was binding in the real-time energy market over a period, by zone.

In the first three months of 2026, in the day-ahead energy market, the 500 kV system, 16 of 21 zones, and PJM/MISO experienced congestion resulting from one or more constraints binding for 25 or more hours, or resulting from a binding interface constraint (Table 3-98).[182] Table 3-98 shows that the 500 kV system, 11 of 21 zones and PJM/MISO experienced congestion resulting from one or more constraints binding for 25 or more hours or resulting from a binding interface constraint in the first three months of every year from 2017 through 2026. DUKE and one zone did not experience congestion resulting from one or more constraints binding for 25 or more hours or resulting from any binding interface constraint in the first three months of any year from 2017 through 2026.

181 See the MMU Technical Reference for PJM Markets, at "Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

Table 3-98 Day-ahead congestion hours resulting from one or more constraints binding for 25 or more hours: January through March, 2017 through 2026

	(Jan - Mar)									
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
500 kV System	2,167	2,041	1,514	1,867	353	946	214	594	896	415
ACEC	898	820	2,119	1,023	241	69	681	294	67	0
AEP	14,180	8,552	3,514	1,517	1,386	860	2,204	2,201	1,967	510
APS	3,018	1,068	813	916	1,099	904	668	960	1,021	1,870
ATSI	1,518	1,228	632	32	0	220	428	304	73	347
BGE	2,943	1,933	883	723	1,426	117	508	87	430	677
COMED	18,294	9,476	1,744	1,068	729	987	747	2,580	1,714	3,096
DAY	188	176	0	187	0	0	90	0	0	0
DEOK	1,465	1,045	245	0	253	142	282	0	0	0
DLCO	0	74	0	0	0	97	0	0	52	110
DOM	1,828	1,652	74	238	222	1,116	898	665	1,078	821
DPL	3,872	3,287	1,636	1,169	1,155	896	1,181	1,468	1,251	799
DUKE	0	0	0	0	0	0	0	0	0	0
DUQ	0	0	0	0	0	0	0	0	0	0
EKPC	283	133	0	0	0	0	26	29	0	0
JCPLC	1,372	728	69	0	0	0	904	426	138	0
MEC	1,473	1,945	1,052	291	318	482	732	1,039	959	649
NYISO	515	0	0	0	0	0	0	0	0	0
OVEC	440	0	0	736	0	66	600	223	522	53
PE	5,909	4,224	1,669	1,701	103	1,970	773	3,105	3,377	2,839
PECO	3,067	1,039	392	655	347	669	1,735	1,314	768	603
PEPCO	316	79	103	0	0	174	130	0	167	45
PJM/MISO	7,429	7,279	3,650	1,952	1,532	3,828	2,175	898	3,130	3,610
PPL	2,060	1,030	3,314	1,587	1,651	2,776	704	849	562	726
PSEG	6,091	4,070	1,506	362	2,244	3,015	1,090	971	1,189	1,550
REC	0	0	215	0	349	595	730	112	64	0
TVA	0	0	257	0	0	0	0	0	0	108

182 A constraint is mapped to the 500 kV system if its voltage is 500 kV and it is located in one of the zones including AECO, BGE, DPL, JCPLC, MEC, PECO, PENELEC, PEPCO, PPL and PSEG. All PJM/MISO reciprocally coordinated flowgates (RCF) are mapped to MISO regardless of the location of the flowgates. All PJM/NYISO RCF are mapped to NYISO as location regardless of the location of the flowgates.

In the first three months of 2026, in the real-time energy market, the 500 kV system, 15 of 21 zones, and PJM/MISO experienced congestion resulting from one or more constraints binding for 25 or more hours, or resulting from a binding interface constraint (Table 3-99).[183] Table 3-99 shows that the 500 kV system, five zones, and PJM/MISO experienced congestion resulting from one or more constraints binding for 25 or more hours or resulting from a binding interface constraint in the first three months of every year from 2017 through 2026. Six zones (DAY, JCPLC, DUQ, OVEC, PEPCO and REC), and DUKE did not experience congestion resulting from one or more constraints binding for 25 or more hours or resulting from any binding interface constraint in the first three years in any year from 2017 through 2026.[184]

183 A constraint is mapped to the 500 kV system if its voltage is 500 kV and it is located in one of the zones including AECO, BGE, DPL, JCPLC, MEC, PECO, PENELEC, PEPCO, PPL and PSEG. All PJM/MISO reciprocally coordinated flowgates (RCF) are mapped to MISO regardless of the location of the flowgates. All PJM/NYISO RCF are mapped to NYISO as location regardless of the location of the flowgates.

184 In this report, the MMU used the dispatch run marginal resource and sensitivity factor data, rather than the pricing run data, in the analysis of constraints since 2021 because the PJM pricing run sensitivity factor data for day-ahead LMP was not correct for a small number of hours. The PJM pricing run LMPs are the final settlement LMPs.

Table 3-99 Real-time congestion hours resulting from one or more constraints binding for 25 or more hours: January through March, 2017 through 2026

	(Jan - Mar)									
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
500 kV System	157	357	519	1,151	130	747	26	252	309	706
ACEC	0	0	112	0	0	0	0	0	0	0
AEP	56	525	126	214	806	124	323	640	486	485
APS	0	0	30	181	115	82	0	133	324	996
ATSI	119	473	0	0	0	165	88	165	87	203
BGE	476	881	134	266	776	67	128	50	145	369
COMED	559	287	207	492	282	396	320	1,180	939	1,796
DAY	0	0	0	0	0	0	0	0	0	0
DEOK	0	25	0	0	93	46	0	0	0	45
DLCO	0	57	0	0	0	0	0	0	0	62
DOM	52	91	0	236	65	615	149	88	480	236
DPL	389	141	0	0	165	0	0	0	128	32
DUKE	0	0	0	0	0	0	0	0	0	0
DUQ	0	0	0	0	0	0	0	0	0	0
EKPC	0	45	0	0	0	0	0	0	0	0
EXT	348	0	0	51	0	0	0	0	0	0
JCPLC	0	0	0	0	0	0	0	0	0	0
MEC	0	367	92	162	39	51	103	71	256	55
NYISO	332	0	0	0	0	0	0	0	0	0
OVEC	0	0	0	0	0	0	0	0	0	0
PE	525	738	865	945	75	1,142	213	1,945	1,784	1,800
PECO	772	37	109	200	267	404	858	557	453	472
PEPCO	0	0	0	0	0	0	0	0	0	0
PJM/MISO	1,302	1,296	1,318	918	815	2,726	1,291	576	2,212	1,786
PPL	137	0	458	294	358	521	91	62	50	187
PSEG	0	125	202	0	811	463	38	0	54	219
REC	0	0	0	0	0	0	0	0	0	0
TVA	0	0	54	0	0	31	0	0	0	80

In the PJM Day-Ahead Energy Market, the TPS test is performed in PROBE, as part of the unit commitment process. Table 3-100 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing the TPS test for the interface constraints in the PJM Day-Ahead Energy Market.

Table 3-100 Day-ahead three pivotal supplier test details for internal interface constraints: January through March, 2026

Constraint	Period	Number of Tests	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
AEP - DOM	Peak	17	398	213	20	5	16
	Off Peak	35	505	1,197	34	24	10
AP South	Peak	22	620	1,644	39	26	13
	Off Peak	42	499	949	35	14	21
BCPEP	Peak	16	367	460	13	4	8
	Off Peak	7	828	492	18	0	18
Bedington - Black Oak	Peak	62	152	186	27	10	17
	Off Peak	95	159	444	33	23	10
West	Peak	17	1,073	1,574	29	14	15
	Off Peak	0	0	0	0	0	0

Table 3-101 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market, whether the TPS test was applied, and the average number of owners passing and failing the TPS test for the 10 constraints that were binding for the most hours in the day-ahead energy market. In the day-ahead energy market, the TPS test evaluates each constraint that was binding for each hour during the operating day after the initial unit commitment run. The set of constraints that are binding in the unit commitment run, for which the TPS test is applied, is not necessarily the same as the set of constraints that bind in the final day-ahead energy market solution. This is because PJM's day-ahead market is solved in three stages, and the initial set of constraints is from the Resource Scheduling and Commitment (RSC) (unit commitment) stage while the final set of binding constraints is from the Scheduling Pricing and Dispatch (SPD) (unit dispatch) stage.[185] The PJM approach fails to apply the TPS test to market sellers that provide relief to constraints in the final dispatch solution, and therefore fails to mitigate such sellers for market power.

The MMU recommends that PJM modify the process for 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.

Table 3-101 Day-ahead three pivotal supplier test details for top 10 congested constraints: January through March, 2026

Constraint	Period	Number of Tests	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
East Towanda - Hillside	Peak	199	177	200	11	2	10
	Off Peak	206	179	262	13	2	11
Haumesser Road - Steward	Peak	543	191	152	8	0	8
	Off Peak	560	189	121	7	0	7
Burnham - Munster	Peak	331	413	732	36	17	19
	Off Peak	624	558	1,115	35	21	14
Nottingham	Peak	237	498	1,090	45	31	14
	Off Peak	233	349	1,037	39	32	7
State Line - Roxana	Peak	70	76	53	7	1	6
	Off Peak	287	138	93	12	1	11
Gardners - Texas Eastern	Peak	282	89	20	6	0	6
	Off Peak	168	116	22	4	0	4
Cedar Grove - Clifton	Peak	68	90	67	3	0	3
	Off Peak	12	49	150	6	0	6
Graceton - Manor	Peak	179	268	379	27	12	16
	Off Peak	277	256	560	28	17	10
Chicago Ave - Praxair	Peak	14	77	124	21	11	10
	Off Peak	47	108	23	10	0	10
Lenox - Macnew Tap	Peak	3	4	6	6	0	6
	Off Peak	0	0	0	0	0	0

The local market structure in the real-time energy market associated with each of the frequently binding constraints was analyzed using the three pivotal supplier results for the first three months of 2026.[186] While the real-time constraint hours include constraints that were binding in the five minute real-time dispatch solution (RT SCED), IT SCED, the software that performs the TPS test, may contain different binding constraints because IT SCED looks ahead to target times that are in the near future to solve for constraints that could be binding, using the load forecast for those times.[187] IT SCED solves for target

185 *See* PJM. "Manual 11: Energy & Ancillary Services Market Operations," Section 5.2.6, Rev. 136 (Oct. 1, 2025).

186 See the *MMU Technical Reference for PJM Markets*, p. 38 "Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

187 Prior to September 1, 2021, the real-time binding constraints were identical in the dispatch (RT SCED) and pricing (LPC) solutions. Beginning September 1, 2021, with implementation of fast start pricing, the set of binding constraints can differ between RT SCED and LPC pricing solutions. The set of constraints reported here are based on the binding constraints in RT SCED. This is because PJM commits and mitigates units based on a dispatch solution in IT SCED without fast start pricing.

times that occur at 15 minute time increments, unlike RT SCED that solves for every five minute time increment. The TPS statistics shown in this section present the data from the IT SCED TPS solution. Some IT SCED TPS solutions are used to commit units, while others are not. PJM operators have discretion in choosing which units to commit and which IT SCED results to use as the basis for the commitment and therefore which units are tested for market power using the TPS test. The results of the TPS test are shown for tests that could have resulted in offer capping and tests that did result in offer capping.

Table 3-102 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing for the interface constraints in the PJM Real-Time Energy Market. Table 3-103 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing for the 10 constraints that were binding for the most hours in the PJM Real-Time Energy Market. Table 3-102 and Table 3-103 include analysis of all the tests for every target time where IT SCED determined that constraint relief was needed for each of the constraints shown. The same target time can be evaluated by multiple IT SCED cases at different look ahead times. Each 15 minute target time is solved by 12 different IT SCED cases at different look ahead times. The set of binding constraints for a target time may be different in 12 look ahead IT SCED solutions.

Table 3-102 Real-time three pivotal supplier test details for internal interface constraints: January through March, 2026

Constraint	Period	Number of Tests	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Bedington - Black Oak	Peak	2,056	285	151	12	1	11
	Off Peak	2,831	342	160	11	0	11
AEP - DOM	Peak	378	585	367	11	0	11
	Off Peak	2,409	665	399	12	0	12
AP South	Peak	48	3,689	2,829	58	0	58
	Off Peak	5	1,103	1,408	34	3	31

Table 3-103 Real-time three pivotal supplier test details for top 10 congested constraints: January through March, 2026

Constraint	Period	Number of Tests	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
East Towanda - Hillside	Peak	17,731	82	114	3	0	2
	Off Peak	21,469	72	110	2	0	2
Haumesser Road - Steward	Peak	9,330	55	91	2	0	2
	Off Peak	9,802	38	69	2	0	2
Burnham - Munster	Peak	6,988	237	213	10	1	9
	Off Peak	13,474	219	173	8	1	7
State Line - Roxana	Peak	2,477	62	20	3	0	3
	Off Peak	7,922	54	21	2	0	2
Chicago Ave - Praxair	Peak	1,977	47	20	3	0	3
	Off Peak	4,786	34	16	2	0	2
Nottingham	Peak	9,963	207	298	15	4	11
	Off Peak	8,364	180	248	13	2	11
Bedington	Peak	6,636	78	17	3	0	3
	Off Peak	10,598	104	16	3	0	3
Kewanee	Peak	1,682	20	76	1	0	1
	Off Peak	1,978	14	62	1	0	1
Lenox - Macnew Tap	Peak	4,681	18	29	3	0	3
	Off Peak	4,958	19	28	2	0	2
Pruntytown	Peak	3,095	63	18	1	0	1
	Off Peak	3,291	92	14	1	0	1

The three pivotal supplier test is applied every time the IT SCED solution indicates that incremental relief is needed to relieve a transmission constraint. While every system solution that requires incremental relief to transmission constraints will result in a test, not all tested providers of effective supply are eligible for offer capping. Steam unit offers that are offer capped in the day-ahead energy market continue to be offer capped in the real-time energy market regardless of their inclusion in the TPS test in real time or the outcome of the TPS test in real time. Steam unit offers that are not offer capped in the day-ahead energy market continue to not be offer capped in the real-time energy market regardless of their inclusion in the TPS test in real time or the outcome of the TPS test in real time.[188] Offline units that are committed to provide relief for a transmission constraint, whose owners fail the TPS test, are committed on the cheaper of their cost or price-based offers. Beginning

188 If a steam unit were to lower its cost-based offer in real time, it would become eligible for offer capping based on the online TPS test.

November 1, 2017, with the introduction of hourly offers and intraday offer updates, online units whose commitment is extended beyond the day-ahead or real-time commitment, and whose owners fail the TPS test, are also switched to the cost-based offer if it is cheaper than the price-based offer.

Units committed in the day-ahead market often fail the TPS test in the real-time market when they are redispatched to provide relief to transmission constraints, even though they did not fail the TPS test in the day-ahead market. Day-ahead committed units are not evaluated for offer capping in real-time unless they update their cost-based offer. These units are able to set prices with a positive markup in the real-time market. Units that cleared the day-ahead market on their price based schedule were evaluated to identify the units whose offers were mitigated in real-time and the units that cleared on price offers in real-time despite failing the real-time TPS test. Table 3-104 shows that, in the first three months of 2026, 5.1 percent of unit hours that cleared the day-ahead market on their price based offer were switched to cost in real-time. Table 3-104 shows that 10.4 percent of unit hours that cleared the day-ahead market on their price based offer cleared on their price based offer in real-time despite failing the real-time TPS test.

Table 3-104 Day-ahead units committed on price-based offers that cleared real-time: January through March, 2025 and 2026)

Year (Jan-Mar)	Day Ahead Price Based Unit Hours That Cleared Real-Time			Percent Day Ahead Price Based Unit Hours That Cleared Real-Time	
	On Cost	On Price	On Price and Failed TPS Test	On Cost	On Price and Failed TPS Test
2025	32,506	649,594	62,592	4.8%	9.2%
2026	42,536	788,722	81,658	5.1%	10.4%

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.

Table 3-105 and Table 3-106 provide, for the identified constraints, information on total tests applied, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping in the real-time energy market. Tests where there was at least one offline unit or an online unit eligible for offer capping are considered tests that could have resulted in offer capping. PJM operators also manually commit units for reliability reasons other than providing relief to a binding constraint. Manual commitments are offer capped along with resources that fail the TPS test.

Table 3-105 Summary of real-time three pivotal supplier tests applied for internal interface constraints: January through March, 2026

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Bedington - Black Oak	Peak	2,056	2,056	100.0%	45	2.2%	2.2%
	Off Peak	2,831	2,831	100.0%	85	3.0%	3.0%
AEP - DOM	Peak	378	378	100.0%	21	5.6%	5.6%
	Off Peak	2,409	2,409	100.0%	68	2.8%	2.8%
AP South	Peak	48	48	100.0%	1	2.1%	2.1%
	Off Peak	5	5	100.0%	0	0.0%	0.0%

Table 3-106 Summary of real-time three pivotal supplier tests applied for top 10 congested constraints: January through March, 2026

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
East Towanda - Hillside	Peak	17,731	8,347	47.1%	0	0.0%	0.0%
	Off Peak	21,469	7,607	35.4%	0	0.0%	0.0%
Haumesser Road - Steward	Peak	9,330	1,405	15.1%	0	0.0%	0.0%
	Off Peak	9,802	1,071	10.9%	0	0.0%	0.0%
Burnham - Munster	Peak	6,988	5,566	79.7%	43	0.6%	0.8%
	Off Peak	13,474	11,053	82.0%	51	0.4%	0.5%
State Line - Roxana	Peak	2,477	546	22.0%	1	0.0%	0.2%
	Off Peak	7,922	1,239	15.6%	4	0.1%	0.3%
Chicago Ave - Praxair	Peak	1,977	495	25.0%	0	0.0%	0.0%
	Off Peak	4,786	685	14.3%	0	0.0%	0.0%
Nottingham	Peak	9,963	9,960	100.0%	129	1.3%	1.3%
	Off Peak	8,364	8,353	99.9%	100	1.2%	1.2%
Bedington	Peak	6,636	4,042	60.9%	16	0.2%	0.4%
	Off Peak	10,598	5,739	54.2%	33	0.3%	0.6%
Kewanee	Peak	1,682	0	0.0%	0	0.0%	N/A
	Off Peak	1,978	11	0.6%	0	0.0%	0.0%
Lenox - Macnew Tap	Peak	4,681	1,909	40.8%	1	0.0%	0.1%
	Off Peak	4,958	964	19.4%	1	0.0%	0.1%
Pruntytown	Peak	3,095	1,893	61.2%	0	0.0%	0.0%
	Off Peak	3,291	1,708	51.9%	2	0.1%	0.1%

Offer Capping for Local Market Power

In the PJM energy market, offer capping occurs as a result of structurally noncompetitive local markets and noncompetitive offers in the day-ahead and real-time energy markets. PJM also uses offer capping for units that are committed for reliability reasons, like voltage support and N-2 contingencies, for providing black start and for providing reactive service as well as for conservative operations. There are no explicit rules governing market structure or the exercise of market power in the aggregate energy market.

There are some issues with the application of mitigation in the day-ahead energy market and the real-time energy market when market sellers fail the TPS test. There are also issues with the absence of a TPS test under some conditions. There is no tariff or manual language that defines in detail the application of the TPS test and offer capping in the day-ahead energy market and the real-time energy market. There is no tariff or manual language that defines the PJM process for evaluating units for multi-day commitments in the day-ahead energy market.

In both the day-ahead and real-time energy markets, generators with market power have the ability to evade mitigation by using varying markups in their price-based offers, offering different operating parameters in their price-based and cost-based offers, and using different fuels in their price-based and cost-based offers. These issues can be resolved by simple rule changes.

When an owner fails the TPS test, the units offered by the owner that are committed to provide relief are committed on the cheaper of cost-based or price-based offers. In the day-ahead energy market, PJM commits a unit on the schedule that results in the lower overall system production cost. The day-ahead energy market selects which schedule to use for a resource that failed the TPS test based on its objective of clearing resources to meet the total demand at the lowest bid production cost for the system over the 24 hour period.

In the real-time energy market, PJM uses a dispatch cost formula to compare price-based offers and cost-based offers to select the cheaper offer.[189]

$$\text{Total Dispatch Cost} = \text{Startup Cost} + \sum_{\text{Min Run}} \text{Hourly Dispatch Cost}$$

where the hourly dispatch cost is calculated for each hour using the offers applicable for that hour as:

$$\text{Hourly Dispatch Cost} = (\text{Incremental Energy Offer@EcoMin} \times \text{EcoMin MW}) + \text{NoLoad Cost}$$

The hourly dispatch cost is calculated only at the economic minimum level and not at higher output levels. Given the ability to submit offer curves with different markups at different output levels in the price-based offer, unit owners with market power can evade mitigation by using a low markup at low output levels and a high markup at higher output levels. This strategy is called crossing curves, or markup switching. Figure 3-65 shows an example of offers from a unit that has a negative markup at the economic minimum MW level and a positive markup at the economic maximum MW level. The result would be that a unit that failed the TPS test would be committed on its price-based offer that has a lower dispatch cost, even though the price-based offer is higher than cost-based offer at higher output levels and includes positive markups, inconsistent with the explicit goal of local market power mitigation.

Figure 3-65 Offers with varying markups at different MW output levels

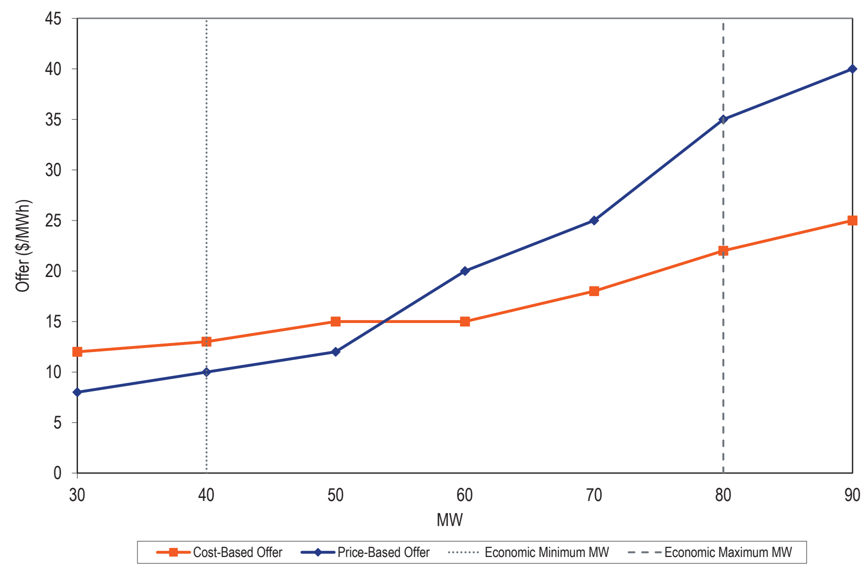


Table 3-107 shows the number and percent of unit schedule hours, by month, when unit offers included crossing curves (markup switch) in the PJM Day-Ahead and Real-Time Energy Markets in the first three months of 2026. The analysis only includes units that offer both price-based and cost-based offers. Units in PJM are only required to submit cost-based offers, but they may elect to offer price-based offers.

189 See OA Schedule 1 § 6.4.1(g).

Table 3-107 Units offered with crossing curves (markup switch): January through March, 2026

	Day-Ahead			Real-Time		
2026	Number of Schedule Hours with Crossing Curves	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Crossing Curves	Number of Schedule Hours with Crossing Curves	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Crossing Curves
Jan	71,460	903,312	7.9%	60,246	850,012	7.1%
Feb	63,354	814,296	7.8%	52,191	735,377	7.1%
Mar	73,320	923,695	7.9%	53,035	779,829	6.8%
Total	208,134	2,641,303	7.9%	165,472	2,365,218	7.0%

Table 3-108 shows the percent of unit schedule hours offered with crossing curves (markup switch), their average markup, their MW output weighted markup, and their average marginal unit LMP and markup contribution, when units failed the three pivotal supplier test in the PJM Day-Ahead Market and were marginal in the Real-Time Energy Market in the first three months of 2022 through 2026. The analysis only includes units that offer both price-based and cost-based offers.

Table 3-108 Marginal units offered with crossing curves (markup switch) and local market power: January through March, 2022 through 2026

	Unit hours with Crossing Curves Committed on Price Offer and Eligible for Offer-Capping DA and Marginal in Real-Time						
Year (Jan-Mar)	Percent of Unit hours with Crossing Curves	Average Markup Day-Ahead	Average Markup Real-Time	Load-Weighted Average Markup Day-Ahead	Load-Weighted Average Markup Real-Time	Average Marginal Unit LMP Contribution	Average Marginal Unit Markup Contribution
2022	10.5%	$19.36	$4.15	$21.64	$7.64	$2.39	$0.22
2023	8.4%	$20.43	$1.65	$17.48	$2.51	$2.04	($0.02)
2024	14.1%	$6.61	($0.79)	$8.44	$2.08	$1.17	($0.08)
2025	15.4%	$12.56	$0.53	$13.12	$1.78	$2.19	$0.20
2026	13.42%	$33.91	$10.32	$46.79	$27.39	$2.57	($0.05)

Table 3-109 shows the percent of unit schedule hours offered with crossing curves (markup switch), their average markup, their MW output weighted markup, and their average marginal unit LMP and markup contribution, when units failed the three pivotal supplier test in the PJM Day-Ahead Market, were marginal in the Real-Time Energy Market and had a negative markup in the PJM Day-Ahead Market in the first three months of 2022 through 2026. The analysis only includes units that offer both price-based and cost-based offers.

Table 3-109 Marginal units offered with crossing curves (markup switch), local market power and negative markup day-ahead: January through March, 2022 through 2026

	Unit hours with Crossing Curves Committed on Price Offer with Negative Markup and Eligible for Offer-Capping DA and Marginal with Positive Markup in Real-Time						
Year (Jan-Mar)	Percent of Unit hours with Crossing Curves	Average Markup Day-Ahead	Average Markup Real-Time	Load-Weighted Average Markup Day-Ahead	Load-Weighted Average Markup Real-Time	Average Marginal Unit LMP Contribution	Average Marginal Unit Markup Contribution
2022	2.5%	($8.31)	$14.11	($7.58)	$19.01	$2.26	$0.06
2023	2.9%	($3.17)	$19.70	($3.18)	$29.40	$2.79	$0.34
2024	4.6%	($3.11)	$9.07	($3.11)	$10.97	$1.00	$0.16
2025	6.0%	($3.03)	$13.54	($2.73)	$15.81	$1.17	$0.25
2026	2.95%	($4.46)	$16.66	($2.86)	$23.65	$2.30	$0.42

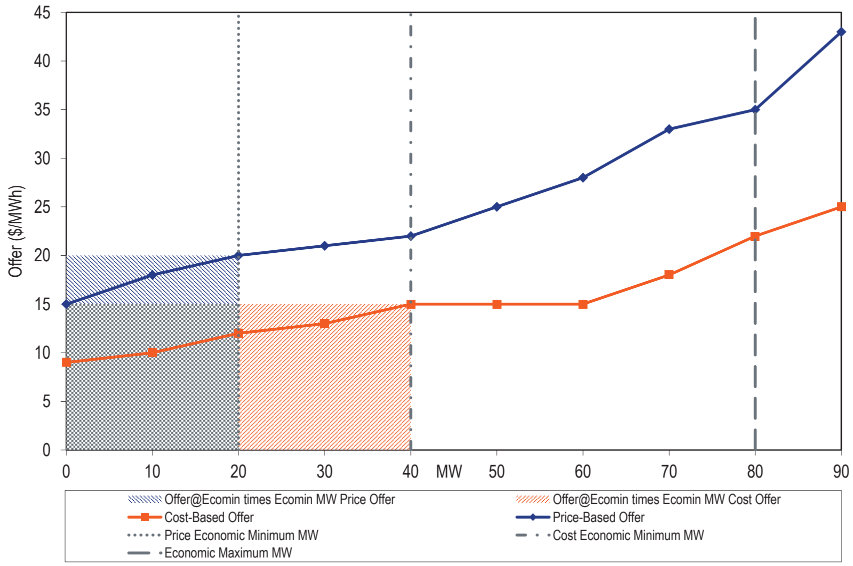
Offering a different economic minimum MW level, different minimum run times, or different start up and notification times in the cost-based and price-based offers can also be used to evade mitigation. For example, a unit may have a price-based offer with a positive markup, but have a shorter minimum run time (MRT) in the price-based offer resulting in a lower dispatch cost for the price-based offer but setting prices at a level that includes a positive markup. Table 3-110 shows the number and percent of unit schedule hours when units offered lower minimum run times in price-based offers than in cost-based offers while having a positive markup in the price-based offer.

Table 3-110 Units offered with lower minimum run time on price compared to cost and with positive markup: January through March, 2026

	Day-Ahead			Real-Time		
2026	Number of Schedule Hours with Lower Min Run Time in Price Compared to Cost	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Lower Min Run Time in Price Compared to Cost	Number of Schedule Hours with Lower Min Run Time in Price Compared to Cost	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Lower Min Run Time in Price Compared to Cost
Jan	3,274	903,312	0.4%	2,981	850,012	0.4%
Feb	3,212	814,296	0.4%	2,251	735,377	0.3%
Mar	3,214	923,695	0.3%	2,099	779,829	0.3%
Total	9,700	2,641,303	0.4%	7,331	2,365,218	0.3%

A unit may offer a lower economic minimum MW level on the price-based offer than the cost-based offer. Such a unit may appear to be cheaper to commit on the price-based offer even with a positive markup. A unit with a positive markup can have lower dispatch cost with the price-based offer with a lower economic minimum level compared to the cost-based offer. Figure 3-66 shows an example of offers from a unit that has a positive markup and a price-based offer with a lower economic minimum MW than the cost-based offer. Keeping the startup cost, Minimum Run Time and no load cost constant between the price-based offer and cost-based offer, the dispatch cost for this unit is lower on the price-based offer than on the cost-based offer solely as a result of the lower economic minimum MW. However, the price-based offer includes a positive markup and could result in setting the market price at a noncompetitive level even after the resource owner fails the TPS test.

Figure 3-66 Offers with a positive markup but different economic minimum MW



The behavior in which units offered lower economic minimum MW in price-based offers than in cost-based offers while having a positive markup in the price-based offer is limited to a number of units that does not permit data to be provided under the PJM confidentiality rules in both the day-ahead and real-time energy markets.

In the case of dual fuel units, if the price-based offer uses a cheaper fuel and the cost-based offer uses a more expensive fuel, the price-based offer will appear to be cheaper even when it includes a markup. Figure 3-67 shows an example of offers by a dual fuel unit, where the active cost-based offer uses a more expensive fuel and the price-based offer uses a cheaper fuel and includes a markup. Table 3-111 shows the number and percent of dual fuel unit hours where the price-based offer does not have a comparable cost-based offer with a matching fuel, and the cost-based offer exceeds the price-based offer. The analysis includes only those units that offered multiple offers (cost or price) with different fuels in the first three months of 2026.

Figure 3-67 Dual fuel unit offers

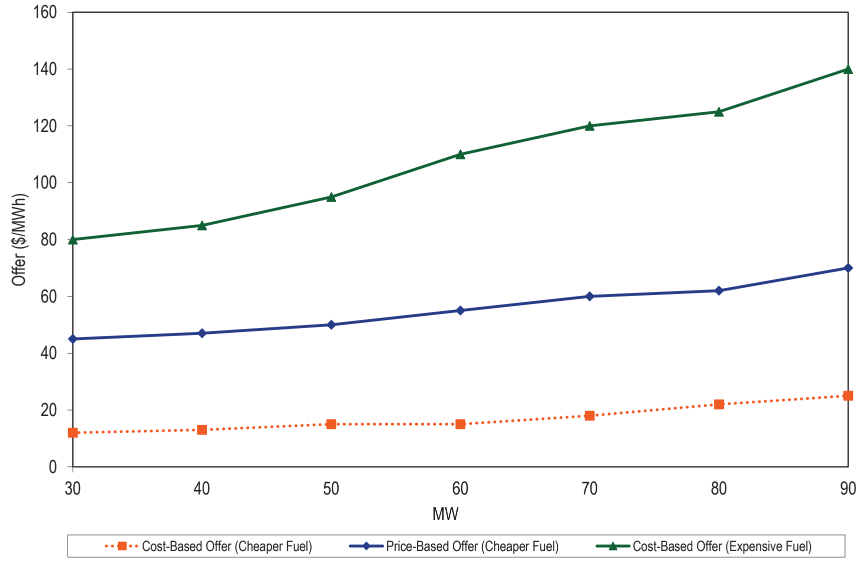


Table 3-111 Dual fuel unit offers with cost-based offers exceeding price-based offers (negative markup) but different fuel: January through March, 2026

	Day-Ahead			Real-Time		
2026	Number of Unit Hours With Negative Markup And No Matching Fuel on Cost	Total Number of Unit Hours By Units With Multiple Fuels	Percent Unit Hours With Negative Markup And No Matching Fuel on Cost	Number of Unit Hours With Negative Markup And No Matching Fuel on Cost	Total Number of Unit Hours By Units With Multiple Fuels	Percent Unit Hours With Negative Markup And No Matching Fuel on Cost
Jan	9,866	195,216	5.1%	9,866	190,925	5.2%
Feb	11,986	179,688	6.7%	11,986	167,397	7.2%
Mar	13,944	212,310	6.6%	13,944	182,450	7.6%
Total	35,796	587,214	6.1%	35,796	540,772	6.6%

These issues can be solved by simple rule changes.[190] 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. This means that the cost-based and price-based offer curves never cross.[191]

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. However, PJM has no plans to implement the improved rules, so 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 should be implemented as soon as possible to help ensure effective market power mitigation.

The issues with offer capping will continue to allow the exercise of market power to affect prices until PJM implements the new approach. Currently, there is no implementation date. The simplified schedule selection process would shorten the time required to reach the day-ahead market solution, which is a market efficiency gain regardless of whether PJM implements combined cycle modelling. The MMU recommends that PJM commit all resources that fail the TPS test on their cost-based offers and that PJM implement that solution as soon as possible. [192]

Levels of offer capping have historically been low in PJM, as shown in Table 3-113. But offer capping remains a critical element of PJM market rules because it is designed to prevent the exercise of local market power. While overall offer capping levels have been low, there are a significant number of units with persistent structural local market power that would have a significant impact on prices in the absence of local market power mitigation. Until November 1, 2017, only uncommitted resources, started to relieve a transmission constraint, were subject to offer capping. Beginning November 1, 2017, under certain circumstances, online resources that are committed beyond their original commitment (day-ahead or real-time) can be offer capped if the owner fails the TPS test, and the

190 The MMU proposed these offer rule changes as part of a broader reform to address generator offer flexibility and associated impact on market power mitigation rules in the Generator Offer Flexibility Senior Task Force (GOFSTF) and subsequently in the MMU's protest in the hourly offers proceeding in Docket No. ER16-372-000, filed December 14, 2015.

191 See related recommendations about mitigation of operating parameters and financial offer parameters.

192 See "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>.

latest available cost-based offer is determined to be lower than the price-based offer.[193] Units running in real time as part of their original commitment on the price-based offer on economics, and that can provide incremental relief to a constraint, cannot be switched to their cost-based offer by PJM.

The offer capping percentages shown in Table 3-112 include units that are committed to provide constraint relief whose owners failed the TPS test in the energy market, but excluding units that were committed for reliability reasons, providing black start or providing reactive support. Offer capped unit run hours and offer capped generation (in MWh) are shown as a percentage of the total run hours and the total generation (MWh) from all the units in the PJM energy market.[194] Beginning November 1, 2017, with the introduction of hourly offers, certain online units, whose owners fail the TPS test in the real-time energy market for providing constraint relief, can be offer capped and dispatched on their cost-based offer subsequent to a real-time hourly offer update.

Table 3-112 Offer capping statistics for units committed for constraints: January through March, 2018 to 2026

	Real-Time		Day-Ahead	
Year (Jan - Mar)	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2018	1.0%	0.4%	0.1%	0.1%
2019	0.6%	0.5%	0.2%	0.2%
2020	0.7%	1.1%	0.8%	0.8%
2021	1.2%	0.9%	0.9%	0.7%
2022	1.1%	1.0%	1.4%	1.0%
2023	0.7%	0.5%	1.1%	0.5%
2024	0.3%	0.2%	1.3%	0.6%
2025	1.4%	1.5%	2.1%	1.3%
2026	1.7%	1.3%	3.4%	1.5%

Table 3-113 shows the offer capping percentages including both units committed to provide constraint relief and units committed for reliability reasons, black start or reactive support. Reliability reasons include reactive support or local voltage support. PJM creates closed loop interfaces to, in some cases, model reactive constraints. The closed loop interface creates demand for the output of the resource needed to provide reactive power. The resulting higher LMPs in the closed loop interfaces increased economic dispatch, which contributed to the reduction in units offer capped for reactive support over time in Table 3-114. In instances where units are committed and offer capped for the modeled closed loop interface constraints, they are considered offer capped for providing constraint relief, and not for reliability. They are included in the offer capping percentages in Table 3-112. Prior to closed loop interfaces, these units were considered as committed for reactive support, and were included in the offer capping statistics for reliability in Table 3-114.

Table 3-113 Offer capping statistics for units committed for constraints or for reliability: January through March, 2018 to 2026

	Real-Time		Day-Ahead	
Year (Jan - Mar)	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2018	1.1%	0.5%	0.1%	0.1%
2019	0.6%	0.5%	0.2%	0.2%
2020	0.7%	1.1%	0.8%	0.8%
2021	1.2%	0.9%	1.0%	0.7%
2022	1.1%	1.0%	1.4%	0.6%
2023	0.7%	0.5%	1.1%	0.6%
2024	0.3%	0.2%	1.4%	0.8%
2025	1.5%	1.7%	2.1%	1.3%
2026	1.7%	1.4%	3.4%	1.5%

193 See OA Schedule 1 § 6.4.1.
194 Prior to the *2018 Quarterly State of the Market Report for PJM: January through June*, these tables presented the offer cap percentages based on total bid unit hours and total load MWh. Beginning with the quarterly report for January through June, 2018, the statistics have been updated with percentages based on run hours and total generation MWh from units modeled in the energy market.

Table 3-114 shows the offer capping percentages only for units committed for reliability reasons, black start or reactive support. The low offer capping percentages do not mean that units manually 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.[195]

Table 3-114 Offer capping statistics for units committed for reliability: January through March, 2018 to 2026

	Real-Time		Day-Ahead	
Year (Jan - Mar)	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2018	0.07%	0.14%	0.02%	0.04%
2019	0.00%	0.00%	0.00%	0.00%
2020	0.00%	0.00%	0.00%	0.00%
2021	0.03%	0.01%	0.03%	0.01%
2022	0.00%	0.01%	0.00%	0.00%
2023	0.03%	0.03%	0.06%	0.05%
2024	0.01%	0.00%	0.09%	0.17%
2025	0.13%	0.25%	0.00%	0.00%
2026	0.01%	0.04%	0.02%	0.04%

Table 3-115 presents data on the frequency with which units were offer capped in the first three months of 2025 and 2026 as a result of failing the TPS test to provide energy for constraint relief in the real-time energy market, or for reliability reasons.

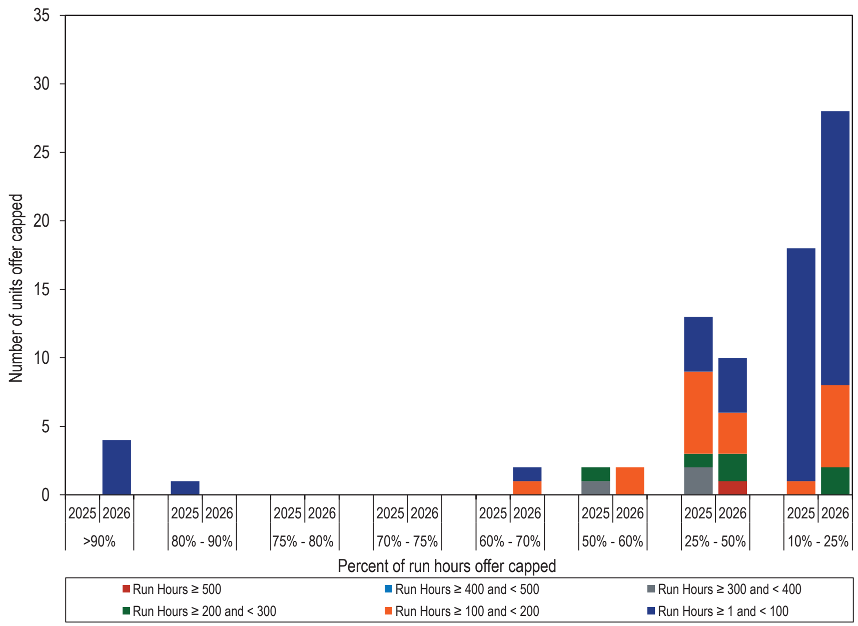
Table 3-115 Real-time offer capped unit statistics: January through March, 2025 and 2026

		Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:		Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2025	0	0	0	0	0	0
	2026	0	0	0	0	0	4
80% and < 90%	2025	0	0	0	0	0	1
	2026	0	0	0	0	0	0
75% and < 80%	2025	0	0	0	0	0	0
	2026	0	0	0	0	0	0
70% and < 75%	2025	0	0	0	0	0	0
	2026	0	0	0	0	0	0
60% and < 70%	2025	0	0	0	0	0	0
	2026	0	0	0	0	1	1
50% and < 60%	2025	0	0	1	1	0	0
	2026	0	0	0	0	2	0
25% and < 50%	2025	0	0	2	1	6	4
	2026	1	0	0	2	3	4
10% and < 25%	2025	0	0	0	0	1	17
	2026	0	0	0	2	6	20

195 OA Schedule 1, Section 6.4.1.

Figure 3-68 shows the frequency with which units were offer capped in the first three months of 2025 and 2026 for failing the TPS test to provide energy for constraint relief in the real-time energy market or for reliability reasons.

Figure 3-68 Real-time offer capped unit statistics: January through March, 2025 and 2026



In response to FERC's request for Common Metrics for 2019 through 2022, which were published in FERC's 2023 Common Metrics Staff report, PJM filed a report stating that between 2019 and 2022 the percent of unit hours in the day-ahead energy market with active market power mitigation was between 78.8 and 100 percent, while the actual results were between 1.4 and 1.6 percent.[196] [197] PJM also reported that between 2019 and 2022, the percent of unit intervals in the real-time energy market with active market power mitigation was between 43.3 and 53.3 percent, while the actual results were between 1.0 and 1.7 percent. PJM's reported results were incorrect because PJM provided hours of mitigation instead of unit hours or unit intervals mitigated. In the day-ahead market, a mitigated unit hour is one unit mitigated for one hour. The denominator is all cleared units cleared for all hours. In the real-time market, a mitigated unit interval is one unit mitigated for one interval. The denominator is all cleared units for all intervals. For example, if there were 10 units running in a given hour in the day-ahead market, if one unit was mitigated for that hour, then the percent of unit hours mitigated would be 10 percent, but PJM defined the percent mitigated as 100 percent of the hour. The PJM filed report dramatically overstated the frequency of market power mitigation in the PJM energy market. The MMU has correctly reported this metric in the State of the Market Reports for 2002 and subsequent years. The MMU also reports the MWh subject to market power mitigation, which reflects the relative size of the units subject to market power mitigation.

Markup Index

Markup is a summary measure of the degree to which a participant's offer behavior or conduct for individual units is competitive. When a seller makes a competitive offer, markup is zero. When a seller exercises market power in its offer, markup is positive. The degree of markup increases with the degree of market power. The markup index for each marginal unit is calculated as (Price – Cost)/Price.[198] The markup index is normalized and can vary from -1.00 when the offer price is less than the cost-based offer price, to 1.00 when the offer price is higher than the cost-based offer price. The markup index does not measure the impact of unit markup on total LMP. The dollar markup for a unit is the difference between price and cost.

Real-Time Markup Index

Table 3-116 shows the average markup index of marginal units in the real-time energy market, by offer price category using unadjusted cost-based offers. Table 3-117 shows the average markup index of marginal units in the real-time energy market, by offer price category using adjusted cost-based offers. The unadjusted markup is the difference between the price-based offer and the cost-based offer including the 10 percent adder in the cost-based offer at the dispatch point on the offer curves. The adjusted markup is the

196 See Common Performance Metrics, Docket No. AD19-16-000, PJM Compliance Filing, PJM Metrics Spreadsheet 2023 (April 17, 2023).
197 See 2023 Common Metrics: Performance Metrics for ISOs, RTOs, and Regions Outside ISOs and RTOs for the Reporting Period 2019 to 2022, FERC Staff Report (January 31, 2024), <https://elibrary.ferc.gov/eLibrary/filelist?accession_num=20240131-4000>.

198 In order to normalize the index results (i.e., bound the results between +1.00 and -1.00) for comparison across both low and high cost units, the index is calculated as (Price – Cost)/Price when price is greater than cost, and (Price – Cost)/Cost when price is less than cost.

difference between the price-based offer and the cost-based offer excluding the 10 percent adder from the cost-based offer. The adjusted markup is calculated for coal, gas and oil units because these units have consistently had price-based offers less than cost-based offers.[199] The markup is negative if the cost-based offer of the marginal unit is greater than its price-based offer at its operating point.

All generating units are allowed to add an additional 10 percent to their cost-based offer. The 10 percent adder was included prior to the implementation of PJM markets in 1999, based on the uncertainty of calculating the hourly operating costs of CTs under changing ambient conditions. The owners of coal units, facing competition, typically exclude the additional 10 percent from their actual offers. The owners of many gas fired and oil fired units have also begun to exclude the 10 percent adder. The introduction of hourly offers and intraday offer updates in November 2017 allows gas and oil generators to directly incorporate the impact of ambient temperature changes in fuel consumption in offers.

PJM implemented Fast Start Pricing on September 1, 2021. For all the fast start marginal units beginning on September 1, 2021, the markup includes markup in the incremental offer, markup in the amortized start up offer, and markup in the amortized no load offer.

Even the adjusted markup overestimates the negative markup because units facing increased competitive pressure have excluded both the 10 percent and components of operating and maintenance costs that are not short run marginal costs. The PJM Market rules permit the 10 percent adder and maintenance costs, which are not short run marginal costs, under the definition of cost-based offers. Actual market behavior reflects the fact that neither is part of a competitive offer and neither is a short run marginal cost.[200]

In the first three months of 2026, the average dollar markup of units with offer prices less than $10 was negative (-$0.78 per MWh) when using unadjusted cost-based offers. The average dollar markup of units with offer prices between $10 and $15 was negative (-3.41 per MWh) when using unadjusted cost-based offers. Negative markup means the unit is offering to run at a price less than its cost-based offer, revealing a short run marginal cost that is less than the maximum allowable cost-based offer under the PJM Market Rules.

Some marginal units did have substantial markups. Among the units that were marginal in the first three months of 2026, 6.7 percent had offer prices above $150 per MWh. Among the units that were marginal in the first three months of 2025, 4.7 percent had offer prices greater than $150 per MWh. Using the unadjusted cost-based offers, the highest markup for any marginal unit in the first three months of 2026 was more than $900, and the highest markup in the first three months of 2025 was more than $800.

Table 3-116 Real-time average marginal unit markup index (By offer price category unadjusted): January through March, 2025 and 2026

	2025 (Jan - Mar)			2026 (Jan - Mar)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	(0.16)	($5.04)	20.5%	0.08	($0.78)	23.9%
$10 to $15	(0.27)	($7.00)	0.9%	(0.17)	($3.41)	3.7%
$15 to $20	(0.13)	($3.23)	6.1%	(0.09)	($1.97)	17.5%
$20 to $25	(0.07)	($1.98)	21.6%	(0.08)	($2.62)	10.9%
$25 to $50	(0.03)	($1.84)	36.0%	(0.05)	($2.46)	27.1%
$50 to $75	0.01	($1.65)	6.3%	(0.01)	($4.65)	5.7%
$75 to $100	0.06	$3.94	2.1%	0.05	($2.04)	2.1%
$100 to $125	0.07	$7.12	1.0%	0.06	($1.53)	1.3%
$125 to $150	0.09	$10.75	0.8%	0.06	$1.41	1.1%
>= $150	0.02	$5.00	4.7%	0.06	$11.11	6.7%
All Offers	(0.06)	($2.01)	100.0%	(0.03)	($1.18)	100.0%

199 The MMU will calculate adjusted markup for gas units also in future reports because gas units also more consistently have price-based offers less than cost-based offers.
200 See PJM. "Manual 15: Cost Development Guidelines," Rev. 47 (Oct. 1, 2025).

Table 3-118 shows the percentage of marginal units that had markups, calculated using unadjusted cost-based offers, below, above and equal to zero for coal, gas and oil fuel types.[201]

Table 3-117 Real-time average marginal unit markup index (By offer price category adjusted): January through March, 2025 and 2026

	2025 (Jan - Mar)			2026 (Jan - Mar)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	(0.16)	($4.76)	20.5%	0.08	($0.67)	23.9%
$10 to $15	(0.20)	($5.31)	0.9%	(0.10)	($1.97)	3.7%
$15 to $20	(0.05)	($1.45)	6.1%	(0.01)	($0.39)	17.5%
$20 to $25	0.01	$0.03	21.6%	0.00	($0.62)	10.9%
$25 to $50	0.04	$0.99	36.0%	0.03	$0.38	27.1%
$50 to $75	0.07	$2.71	6.3%	0.07	$0.32	5.7%
$75 to $100	0.12	$9.57	2.1%	0.12	$4.54	2.1%
$100 to $125	0.13	$14.16	1.0%	0.11	$6.28	1.3%
$125 to $150	0.15	$18.85	0.8%	0.12	$11.19	1.1%
>= $150	0.11	$27.48	4.7%	0.13	$32.34	6.7%
All Offers	0.01	$1.20	100.0%	0.04	$2.22	100.0%

Table 3-119 shows the percentage of marginal units that had markups, calculated using adjusted cost-based offers, below, above and equal to zero for coal, gas and oil fuel types. In the first three months of 2026, using unadjusted cost-based offers for coal units, 53.66 percent of marginal coal units had negative markups. The share of marginal coal units with negative markups at the dispatch point on their offer curve increased from 40.05 percent in the first three months of 2025 to 53.66 percent in the first three months of 2026 when using unadjusted cost based offers.

Table 3-118 Percent of marginal units with markup below, above and equal to zero (By fuel type with unadjusted offers): January through March, 2025 and 2026

	2025 (Jan - Mar)			2026 (Jan - Mar)		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	40.05%	39.15%	20.80%	53.66%	34.39%	11.94%
Gas	67.91%	17.81%	14.28%	64.05%	23.15%	12.80%
Oil	7.40%	88.67%	3.94%	6.06%	91.30%	2.63%

In the first three months of 2026, using adjusted cost-based offers for coal units, 37.31 percent of marginal coal units had negative markups.

Table 3-119 Percent of marginal units with markup below, above and equal to zero (By fuel type with adjusted offers): January through March, 2025 and 2026

	2025 (Jan - Mar)			2026 (Jan - Mar)		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	29.32%	9.95%	60.73%	37.31%	13.61%	49.08%
Gas	25.48%	9.97%	64.55%	29.01%	14.46%	56.53%
Oil	6.21%	87.48%	6.32%	5.88%	90.39%	3.74%

201 Other fuel types were excluded based on data confidentiality rules.

Figure 3-69 shows the frequency distribution of hourly markups for all gas units offered in the first three months of 2025 and 2026 using unadjusted cost-based offers. The highest markup within the economic operating range of the unit's offer curve was used in the frequency distributions.[202] Of the gas units offered in the PJM market in the first three months of 2026, 18.0 percent of gas unit hours had a maximum markup that was negative and 28.9 percent of gas fired unit hours had a maximum markup above $100 per MWh. The share of offered gas units with maximum markup that was negative increased in the first three months of 2026 compared to the first three months of 2025, while the share of marginal gas units with negative markups at the dispatch point decreased.

Figure 3-69 Frequency distribution of highest markup of gas units offered using unadjusted cost offers: January through March, 2025 and 2026

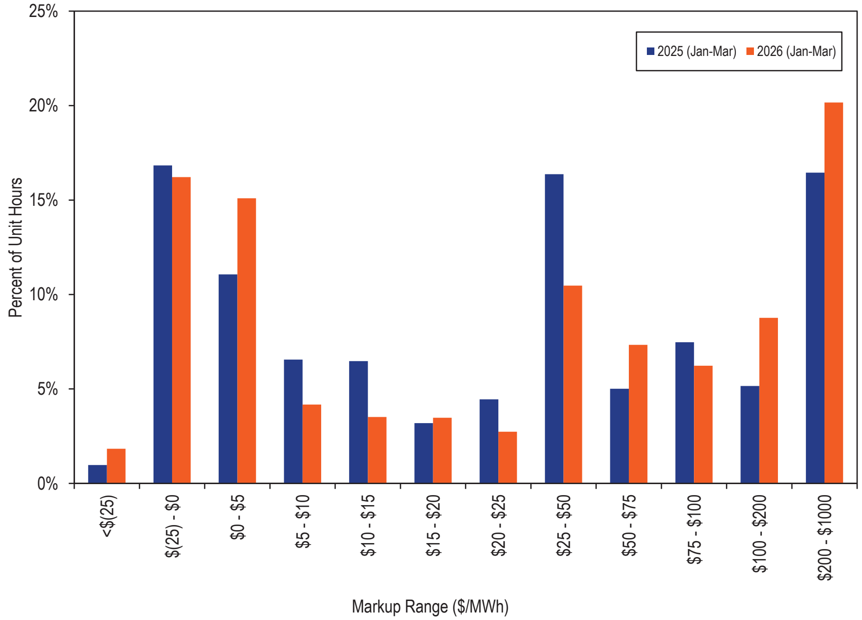


Figure 3-70 shows the frequency distribution of hourly markups for all coal units offered in the first three months of 2025 and the first three months of 2026 using unadjusted cost-based offers. Of the coal units offered in the PJM market in the first three months of 2026, 36.8 percent of coal unit hours had a maximum markup that was negative or equal to zero, increasing from 33.5 percent in the first three months of 2025. The share of offered coal units with maximum markup that was negative and the share of marginal coal units with negative markups at the dispatch point increased in the first three months of 2026 compared to the first three months of 2025.

Figure 3-70 Frequency distribution of highest markup of coal units offered using unadjusted cost offers: January thorugh March, 2025 and 2026

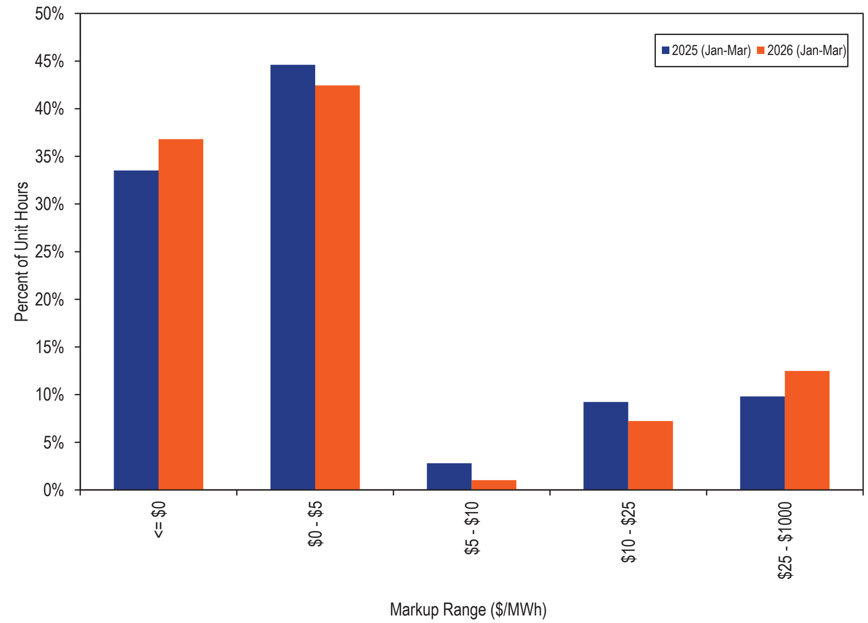
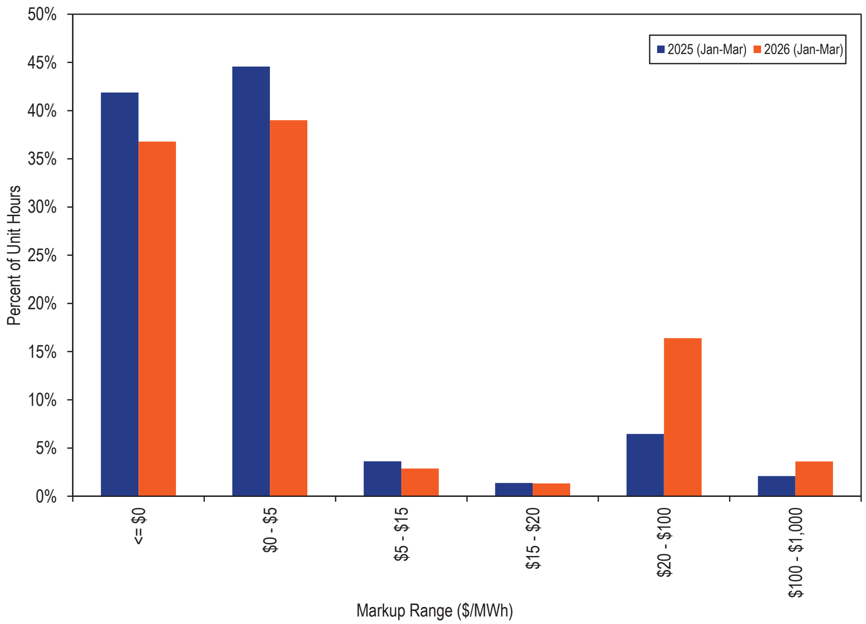


Figure 3-71 shows the frequency distribution of hourly markups for all offered oil units in the first three months of 2025 and the first three months of 2026 using unadjusted cost-based offers. Of the oil units offered in the PJM

202 The categories in the frequency distribution were chosen so as to maintain data confidentiality.

market in the first three months of 2026, 36.8 percent of oil unit hours had a maximum markup that was negative or equal to zero and 3.6 percent of oil fired unit hours had a maximum markup above $100 per MWh.

Figure 3-71 Frequency distribution of highest markup of oil units offered using unadjusted cost offers: January through March, 2025 and 2026

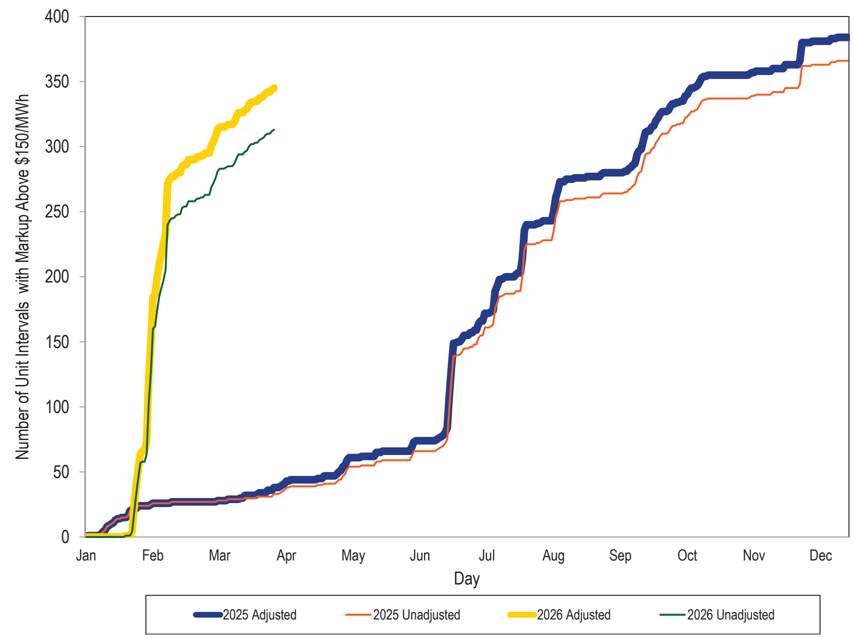


The markup frequency distributions show that a significant proportion of units make price-based offers less than the cost-based offers permitted under the PJM market rules. This behavior means that competitive price-based offers reveal actual unit marginal costs and that PJM market rules permit the inclusion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

The markup behavior shown in the markup frequency distributions also shows that a substantial number of units were offered with high markups, consistent with the exercise of market power.

Figure 3-72 shows the number of marginal unit intervals in the first three months of 2026 and the first three months of 2025 with markup above $150 per MWh.

Figure 3-72 Cumulative number of marginal unit intervals with markups above $150 per MWh: January 2025 through March 2026



Day-Ahead Markup Index

Table 3-120 shows the average markup index of marginal generating units in the day-ahead energy market, by offer price category using unadjusted cost-based offers.[203]

In the first three months of 2026, the average dollar markup of units with offer prices less than $10 was positive ($22.81 per MWh) when using unadjusted

203 The MMU identified an error in the marginal resource identification algorithm within the day ahead clearing optimization. The calculation of generator sensitivity factors and markup index require accurate identification of marginal resources. The error was fixed by the PJM software vendor in March 2025. MMU was unable to calculate markup index for 2024 and the first quarter of 2025 due to the inaccurate identification of marginal resources.

cost-based offers. The average dollar markup of units with offer prices between $10 and $15 was positive ($11.47 per MWh) when using unadjusted cost-based offers. Negative markup means the unit is offering to run at a price less than its cost-based offer, revealing a short run marginal cost that is less than the maximum allowable cost-based offer under the PJM Market Rules.

Some marginal units did have substantial markups. Among the units that were marginal in the first three months of 2026, 7.1 percent had offer prices above $150 per MWh when using unadjusted cost-based offers. Using the unadjusted cost-based offers, the highest markup for any marginal unit in the first three months of 2026 was more than $600 per MWh.

Table 3-120 Average day-ahead marginal unit markup index (By offer price category, unadjusted): January through March, 2026

	2026 (Jan - Mar)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency
< $10	17.65	$22.81	15.9%
$10 to $15	1.15	$11.47	3.1%
$15 to $20	0.27	$3.51	15.5%
$20 to $25	0.14	$2.41	10.8%
$25 to $50	0.04	$0.79	37.0%
$50 to $75	0.09	$4.95	5.8%
$75 to $100	0.15	$12.71	2.3%
$100 to $125	0.21	$23.09	1.4%
$125 to $150	0.20	$25.36	1.1%
>= $150	0.09	$21.45	7.1%
All Offers	1.48	$7.78	100.0%

Table 3-121 shows the average markup index of marginal generating units in the day-ahead energy market, by offer price category using adjusted cost-based offers.

Table 3-121 Average day-ahead marginal unit markup index (By offer price category, adjusted): January through March, 2026

	2026 (Jan - Mar)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency
< $10	17.65	$22.86	15.9%
$10 to $15	1.21	$12.38	3.1%
$15 to $20	0.34	$4.94	15.5%
$20 to $25	0.21	$4.26	10.8%
$25 to $50	0.12	$3.56	37.0%
$50 to $75	0.16	$9.19	5.8%
$75 to $100	0.21	$18.50	2.3%
$100 to $125	0.27	$30.31	1.4%
$125 to $150	0.24	$30.94	1.1%
>= $150	0.15	$42.80	7.1%
All Offers	1.54	$11.32	100.0%

No Load and Start Cost Markup

Generator energy offers in PJM are comprised of three parts, an incremental energy offer curve, no load cost and start cost. In cost-based offers, all three parts are capped at the level allowed by Schedule 2 of the Operating Agreement, the Cost Development Guidelines (Manual 15) and fuel cost policies approved by PJM. In price-based offers, the incremental energy offer curve is capped at $1,000 per MWh (unless the verified cost-based offer exceeds $1,000 per MWh, but cannot exceed $2,000 per MWh). Generators are allowed to choose whether to use price-based or cost-based no load cost and start costs twice a year. If price-based is selected, the no load and start costs do not have a cap, but the offers cannot be changed for six months (April through September and October through March). If cost-based is selected, the cap is the same as the cap of the no load and start costs in the cost-based offers, and the offers can be updated daily or hourly based on changes in costs. Table 3-122 shows the caps on the three parts of cost-based and price-based offers.

Table 3-122 Cost-based and price-based offer caps

Offer Type	No Load and Start Cost Option	Incremental Offer Curve Cap	No Load Cost Cap	Start Cost Cap
Cost-Based	Cost-Based	Based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies		
Price-Based	Cost-Based	$1,000/MWh or based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies if verified cost-based offer exceeds $1,000/MWh but no more than $2,000/MWh.	Based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies	Based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies
	Price-Based		No cap but can only be changed twice a year.	No cap but can only be changed twice a year.

Table 3-123 shows the number of units that chose the cost-based option and the price-based option. In the first three months of 2026, 90 percent of all generators that submitted no load or start costs chose to have cost-based no load and start costs in their price-based offers, the same percent as in the first three months of 2025.

Table 3-123 Number of units selecting cost-based and price-based no load and start costs: January through March, 20254 and 2026

	2025 (Jan -Mar)		2026 (Jan -Mar)	
No Load and Start Cost Option	Number of units	Percent	Number of units	Percent
Cost-Based	466	90%	480	90%
Price-Based	51	10%	56	10%
Total	517	100%	536	100%

Generators can have positive or negative markups in their no load and start costs under the price-based option. Generators cannot have positive markups in no load and start costs when they select the cost-based option. Table 3-124 shows the average markup in the no load and start costs in the first three months of 2025 and 2026. Generators that selected the cost-based start and no load option offered on average with a negative markup on the no load cost and a negative markup on the start costs. The price-based offers were lower than the cost-based offers. In the first three months of 2026, generators that selected the price-based start and no load option offered on average with a negative markup on the no load cost and with very large positive markups on the start costs.

Table 3-124 No load and start cost markup: January through March, 2025 and 2026

Period	No Load and Start Cost Option	No Load Cost	Cold Start Cost	Intermediate Start Cost	Hot Start Cost
2025 (Jan -Mar)	Cost-Based	(14%)	(5%)	(6%)	(7%)
	Price-Based	25%	140%	125%	125%
2026 (Jan -Mar)	Cost-Based	(13%)	(6%)	(6%)	(6%)
	Price-Based	(43%)	63%	65%	71%

Energy Market Cost-Based Offers

The application of market power mitigation rules in the day-ahead energy market and the real-time energy market helps ensure competitive market outcomes even in the presence of structural market power.

Cost-based offers in PJM affect all aspects of the PJM energy market. Cost-based offers affect prices when units are committed and dispatched on their cost-based offers. In the first three months of 2026, 15.9 percent of the marginal units set prices based on cost-based offers, 4.5 percentage points higher than in the first three months of 2025.

The efficacy of market power mitigation rules depends on the definition of a competitive offer. A competitive offer is equal to short run marginal costs. The enforcement of market power mitigation rules is undermined if the definition of a competitive offer is not correct. 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 in the PJM market rules is not correct. Some unit owners include costs that are not short run marginal costs in offers, including maintenance costs. The market rules allow these overstated cost-based offers. This issue can be resolved by simple changes to the PJM market rules to incorporate a clear and accurate definition of short run marginal costs.

The efficacy of market power mitigation rules also depends on the accuracy of cost-based offers. Some unit owners use fuel cost policies that are not algorithmic, verifiable, and systematic. These inadequate fuel cost policies permit overstated fuel costs in cost-based offers.

When market power mitigation is not effective due to inaccurate cost-based offers that exceed short run marginal costs, market power causes increases in market prices above the competitive level.

Short Run Marginal Costs

Short run marginal costs are the only costs relevant to competitive offers in the energy market. Specifically, the competitive energy offer level is the short run marginal cost of production. The current PJM market rules distinguish costs includable in cost-based energy offers from costs includable in cost-based capacity market offers based on whether costs are "directly related to energy production." The rules do not provide a clear standard. Energy production is the sole purpose of a power plant. Therefore, all costs, including the sunk costs, are directly related to energy production. This current ambiguous criterion is incorrect and allows for multiple interpretations, which could lead to tariff violations. The incorrect rules lead to higher energy market prices and higher uplift.

There are three types of costs identified in PJM rules as of April 15, 2019: variable costs, avoidable costs, and fixed costs. The criterion for whether a generator may include a cost in an energy market cost-based offer, a variable cost, is that the cost is "directly related to electric production."[204]

Variable costs, as defined in the PJM rules, are comprised of short run marginal costs and avoidable costs that are directly related to electric production. Short run marginal costs are the cost of inputs consumed or converted to produce energy, and the costs associated with byproducts that result from consuming or converting materials to produce energy, net of any revenues from the sale of those byproducts. The categories of short run marginal costs are fuel costs, emission allowance costs, operating costs, and energy market opportunity costs.[205]

204 See 167 FERC ¶ 61,030 (2019).
205 See OA Schedule 2 § 1.1(a).

Avoidable costs are annual costs that would be avoided if energy were not produced over an annual period. The PJM rules divide avoidable costs into those that are directly related to electric production and those not directly related to electric production. The distinction is ambiguous at best. PJM includes overhaul and maintenance costs, replacement of obsolete equipment, and overtime staffing costs in costs related to electric production. PJM includes taxes, preventative maintenance to auxiliary equipment, improvement of working equipment, maintenance expenses triggered by a time milestone (e.g. annual, weekly) and pipeline reservation charges in costs not related to electric production.

Fixed costs are costs associated with an investment in a facility including the return on and of capital.

The MMU recommends that PJM require that the level of costs includable in cost-based offers in the energy market not exceed the unit's short run marginal cost.

Fuel Cost Policies

Fuel cost policies (FCP) document the process by which market sellers calculate the fuel cost component of their cost-based offers. Short run marginal fuel costs include commodity costs, transportation costs, fees, and taxes for the purchase of fuel.

Fuel Cost Policy Review

Table 3-125 shows the status of all fuel cost policies (FCP). As of March 31, 2026, 719 units (91 percent) had an FCP passed by the MMU and 67 units (nine percent) had an FCP failed by the MMU. The units with fuel cost policies failed by the MMU represented 15,740 MW. All units' FCPs were approved by PJM. As of March 31, 2026, 628 units did not have FCPs. Units without FCPs cannot submit nonzero cost based offers, unless they use the temporary cost method.[206]

206 See OA Schedule 2 § 2.1.

Table 3-125 FCP Status for PJM generating units: March 31, 2026

	MMU Status				Units without
PJM Status	Pass	Submitted	Fail	Total	FCPs
Approved	719	0	67	786	
Rejected	0	0	0	0	
Under Review	0	0	0	0	
Customer Input Required	0	0	0	0	
Submitted	0	0	0	0	
Total	719	0	67	786	628

The MMU performed a detailed review of every FCP. PJM approved the FCPs that the MMU passed. PJM approved every FCP failed by the MMU.

The standards for the MMU's market power evaluation are that FCPs be algorithmic, verifiable and systematic, accurately reflecting the short run marginal cost of producing energy. In its filings with FERC, PJM agreed with the MMU that FCPs should be verifiable and systematic.[207] Verifiable means that the FCP requires a market seller to provide a fuel price that can be calculated by the MMU after the fact with the same data available to the market seller at the time the decision was made, and documentation for that data from a public or a private source. Systematic means that the FCP must document a clearly defined quantitative method or methods for calculating fuel costs, including objective triggers for each method.[208] PJM and FERC did not agree that fuel cost policies should be algorithmic, although PJM's standard effectively requires algorithmic fuel cost policies by describing the requirements.[209] Algorithmic means that the FCP must use a set of defined, logical steps, analogous to a recipe, to calculate the fuel costs. These steps may be as simple as a single number from a contract, a simple average of broker quotes, a simple average of bilateral offers, or the weighted average index price posted on the Intercontinental Exchange trading platform ('ICE').[210]

FCPs are not verifiable and systematic if they are not algorithmic. The natural gas FCPs failed by the MMU and approved by PJM are not verifiable and systematic.

207 Answer of PJM Interconnection, L.L.C. to Protests and Comments, Docket No. ER16-372-002 (October 7, 2016) at P 11 ("October 7th Filing").
208 Protest of the Independent Market Monitor for PJM, Docket No. ER16-372-002 (September 16, 2016) at P 8 ("September 16th Filing").
209 October 7th Filing at P12; 158 FERC ¶ 61,133 at P 57 (2017).
210 September 16th Filing at P 8.

Not all FCPs approved by PJM met the standard of the PJM tariff. The tariff standards that some fuel cost policies did not meet are: accuracy (reflect applicable costs accurately); and fuel contracts (reflect the market seller's applicable commodity and/or transportation contracts where it holds such contracts). [211]

The MMU failed FCPs not related to natural gas submitted by some market sellers because they do not accurately describe the short run marginal cost of fuel. Some policies include contractual terms (in dollars per MWh or in dollars per MMBtu) that do not reflect the actual cost of fuel. The MMU determined that the terms used in these policies do not reflect the cost of fuel based on the information provided by the market sellers and information gathered by the MMU for similar units.

The MMU failed the remaining FCPs because they do not accurately reflect the cost of natural gas. The main issues identified by the MMU in the natural gas policies were the use of available market information that results in inaccurate and overstated expected costs. Overstated costs permit the exercise of market power.

Some of the failed fuel cost polices include the use of available market information that results in inaccurate expected costs because the information does not represent a cleared market price. Some market sellers include the use of offers to sell natural gas on ICE as the sole basis for the cost of natural gas. An offer to sell is not a market clearing price and is not an accurate indication of the expected fuel cost. The price of uncleared offers on the exchange generally exceeds the price of cleared transactions, often by a wide margin. Use of sell offers alone is equivalent to using the supply curve alone to determine the market price of a good without considering the demand curve. It is clearly incorrect.

The FCPs that failed the MMU's evaluation also fail to meet the standards defined in the PJM tariff. PJM should not have approved noncompliant fuel cost policies. The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic.

211 See PJM Operating Agreement Schedule 2 § 2.3 (a).

Units are required to have an approved fuel cost policy before they can submit nonzero cost-based offers or request from PJM the use of a temporary cost method. The temporary cost offer method allows units to submit nonzero cost-based offers without an approved fuel cost policy if they follow the temporary cost offer method. The use of the method results in cost-based offers that do not follow the fuel cost policy rules. The approach significantly weakens market power mitigation by allowing market sellers to make offers without an approved fuel cost policy, allowing the use of an inaccurate and unsupported fuel cost calculation in place of an accurate fuel cost policy.

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.

Cost-Based Offer Penalties

Market sellers are assessed penalties when they submit cost-based offers that do not comply with Schedule 2 of the PJM Operating Agreement and PJM Manual 15.[212] Penalties are assessed when both PJM and the MMU are in agreement.

In the first three months of 2026, penalties were assessed to units owned by fewer than four market participants. Penalty data from fewer than four market participants is considered confidential. Table 3-126 shows the penalties by the year in which participants were notified.

212 See OA Schedule 2 § 6.

Table 3-126 Cost-based offer penalty cases by year notified: May 2017 through December 2025

Year notified	Cases	Assessed penalties	Self Identified	MMU and PJM Disagreement	Pending cases	Number of units impacted	Number of companies impacted
2017	57	56	0	1	0	55	16
2018	187	161	0	26	0	138	35
2019	57	57	0	0	0	57	19
2020	142	137	24	5	0	124	25
2021	129	124	42	5	0	124	21
2022	116	116	51	0	0	110	20
2023	65	65	13	0	0	61	18
2024	77	77	39	0	0	67	21
2025	41	41	13	0	0	41	19
Total	871	834	182	37	0	528	89

Since 2017 through 2025, of the 871 penalty cases, 834 resulted in assessed cost-based offer penalties, 37 resulted in disagreement between the MMU and PJM and zero remain pending. A total of 182 were self identified by market sellers. The 834 cases were from 528 units owned by 89 different companies. The total penalties were $6.1 million, charged to units that totaled 169,536 available MW. The average penalty was $1.57 per available MW. This means that a 100 MW unit would have paid a penalty of $3,768.[213] There is no link between the increased costs to the market that result from a penalized fuel cost policy and the amount of the penalty. The increased costs to the market can exceed the penalty payment and the reverse can also be true. Table 3-127 shows the total cost-based offer penalties since 2017 by year.

213 Cost-based offer penalties are assessed by hour. Therefore, a $1 per available MW penalty results in a total of $24 for a 1 MW unit if the violation is for the entire day.

Table 3-127 Cost-based offer penalties by year: May 2017 through December 2025

Year	Number of units	Number of companies	Penalties	Average Available Capacity Charged (MW)	Average Penalty ($/MW)
2017	92	21	$556,826	16,930	$1.56
2018	127	34	$1,242,102	25,743	$2.28
2019	73	23	$378,245	15,073	$1.14
2020	140	28	$407,283	21,908	$0.85
2021	125	27	$753,463	24,808	$1.31
2022	123	22	$1,613,621	24,385	$2.76
2023	61	15	$333,948	10,383	$1.33
2024	79	22	$549,736	21,900	$1.05
2025	41	19	$216,648	7,854	$1.18
Total	861	78	$6,051,871.55	169,536	$1.57

The incorrect cost-based offers resulted from incorrect application of fuel cost policies, lack of approved fuel cost policies, fuel cost policy violations, miscalculation of no load costs, inclusion of prohibited maintenance costs, use of incorrect incremental heat rates, use of incorrect start cost, and use of incorrect emission costs.

Penalties do not apply when PJM determines that an unforeseen event hindered the market seller's ability to submit a compliant cost-based offer. This allows market sellers to not follow their fuel cost policy, submit cost-based offers that are not verifiable or systematic and not face any penalties for doing so. This practice is inappropriate and should stop.

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.

Cost Development Guidelines

The Cost Development Guidelines contained in PJM Manual 15 do not clearly or accurately describe the short run marginal cost of generation. The MMU recommends that PJM Manual 15 be replaced or updated with a straightforward description of the components of cost-based offers based on short run marginal costs and the correct calculation of cost-based offers for thermal resources. In 2022, PJM made updates recommended by the MMU to Manual 15 to add straightforward descriptions for some of the most essential cost offer calculations.[214]

Variable Operating and Maintenance Costs

PJM Manual 15 and the PJM Operating Agreement Schedule 2 include rules related to VOM costs. On October 29, 2018, PJM filed tariff revisions changing the rules related to VOM costs.[215] The changes proposed by PJM attempted but failed to clarify the rules. The proposed rules defined all costs directly related to electricity production as includable in cost-based offers. This also included the long term maintenance costs of combined cycles and combustion turbines, which had been explicitly excluded in PJM Manual 15.

On April 15, 2019, FERC accepted PJM's filing, subject to revisions requested by FERC.[216] On October 28, 2019, FERC issued a final order accepting PJM's compliance filing.[217] Regardless of the changes, the rules remain unclear and are now inconsistent with economic theory and effective market power mitigation and competitive market results.

Maintenance costs are not short run marginal costs. Generators perform maintenance during outages. Generators do not perform maintenance in the short run, while operating the generating unit. Generators do not perform maintenance in real time to increase the output of a unit. Some maintenance costs are correlated with the historic operation of a generator. Correlation between operating hours or starts and maintenance expenditures over a long run, multiyear time frame does not indicate the necessity of any specific maintenance expenditure to produce power in the short run.

A generating unit does not consume a defined amount of maintenance parts and labor in order to start. A generating unit does not consume a defined amount of maintenance parts and labor in order to produce an additional MWh. Maintenance events do not occur in the short run. The company cannot optimize its maintenance costs in the short run.

214 See PJM Manual 15: Cost Development Guidelines, Revision 47 (Oct. 1, 2025).
215 See PJM Interconnection Maintenance Adder Revisions to the Amended and Restated Operating Agreement, L.L.C., Docket No. EL19-8-000.
216 167 FERC ¶ 61,030 (2019).
217 168 FERC ¶ 61,134 (2019).

PJM allows for the calculation of VOM costs in dollars per MWh, dollars per MMBtu, dollars per run hour, dollars per equivalent operating hour (EOH) and dollars per start. The MMU converted all VOM costs into dollars per MWh using the units' heat rates, the average economic maximum and average minimum run time of the units in 2024.

Table 3-128 shows the average VOM by unit type. The VOM equals the sum of variable operating cost, major maintenance adder and minor maintenance adder as submitted by market participants.

Table 3-128 Effective VOM costs in dollars per MWh in 2025

Unit Type	VOM ($/MWh)
Combined Cycles	$3.18
Combustion Turbines and RICE	$21.98
Gas/Oil Steam Turbines	$11.51
Coal	$6.67

The level of costs accepted by PJM for inclusion in VOM depends on PJM's interpretation of the maintenance activities or expenses directly related to electricity production and the level of detailed support provided by market sellers to PJM.

PJM's VOM review is not adequate to determine whether all costs included in VOM are compliant. PJM's VOM review focuses only on the expenses submitted for the last year of up to 20 years of data. For example, a market seller can provide data from ten years ago without any supporting documentation as long as the data from the current year has documentation. PJM's review is dependent on the level of detail provided by the market seller. As a result of questions raised by the MMU, PJM now requires more details from market sellers, which has led to the appropriate exclusion of expenses that were previously included.[218]

The flaws in PJM's review process for VOM are compounded by the ambiguity in the criteria used to determine if costs are includable. PJM's definition of allowable costs for cost-based offers, "costs resulting from electric production," is so broad as to be meaningless. Most costs incurred at a generating station result from electric production in one way or another. The generator itself would not exist but for the need for electric production. PJM's broad definition cannot identify which costs associated with electric production are includable in cost-based offers. The definition is not verifiable or systematic and permits wide discretion by PJM and generators.

On February 17, 2023, PJM filed tariff revisions changing the rules related to VOM costs. The changes included separating maintenance expenses into major and minor maintenance, allowing the use of default adders for minor maintenance and operating costs and eliminating the annual review requirement for units that choose to use default adders. The proposal, that included the tariff changes, also included Manual 15 changes that introduced additional documentation requirements. Regarding maintenance expenses, market participants will be required to provide all supporting documentation for all expenses submitted, regardless of year. Regarding operating expenses, market participants will be required to provide the amount of consumables used during operation and the cost per unit of each consumable.[219] On April 18, 2023, FERC accepted PJM's filing. Table 3-129 shows the default adders for operating cost and minor maintenance.

218 See "Maintenance Adder & Operating Cost Submission Process," 55-57 PJM presentation to the Tech Change Forum. (April 21, 2020) <https://pjm.com/-/media/committees-groups/forums/tech-change/2020/20200421-special/20200421-item-01-maintenance-adder-and-operating-cost-submission-process.ashx>.

219 See "Maintenance Adder & Operating Cost Submission Process," 55-57 PJM presentation to the Tech Change Forum. (April 21, 2020) <https://pjm.com/-/media/committees-groups/forums/tech-change/2020/20200421-special/20200421-item-01-maintenance-adder-and-operating-cost-submission-process.ashx

Table 3-129 Default operating cost and minor maintenance adder: 2025

Unit Type	Operating Cost ($/MWh)	Minor Maintenance Cost ($/MWh)
Combined Cycle	0.49	1.21
Combustion Turbine	0.92	4.43
Reciprocating Engine	2.00	4.97
Steam Turbine	3.54	2.11

The MMU recommended 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. The revisions to Manual 15 based on the February 17, 2023, filing included this requirement.

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 operational data (e.g. run hours, MWh, MMBtu) that support the maintenance cycle of the equipment being serviced/replaced. The revisions to Manual 15 based on the February 17, 2023, filing partially included this requirement. Even though Manual 15 requires maintenance expenses to be the result of operating hours, starts or a combination of the two, the expenses are not tied to a maintenance cycle. Therefore, it is not possible to distinguish between maintenance that resulted from operating the resource versus maintenance from normal wear and tear.

The MMU understands that companies have different document retention policies but in order to be allowed to include maintenance costs, such costs must be verified, and they cannot be verified without documentation. Supporting documentation includes internal financial records, maintenance project documents, invoices, and contracts. Market participants should be required to provide the operational data (e.g. run hours, MWh, MMBtu) that supports the maintenance cycle of the equipment being serviced/replaced. For example, if equipment is serviced every 5,000 run hours, the market participant must include at least 5,000 run hours of historical operation in its maintenance cost history.

FERC System of Accounts

PJM Manual 15 relies on the FERC System of Accounts, which predates markets and does not define costs consistent with market economics. Market sellers should not rely solely on the FERC System of Accounts for the calculation of their variable operating and maintenance costs. The FERC System of Accounts does not differentiate between short run marginal costs and avoidable costs. The FERC System of Accounts does not differentiate between costs directly related to energy production and costs not directly related to energy production. Reliance on the FERC System of Accounts for the calculation of variable operating and maintenance costs is likely to lead to incorrect, overstated costs.

The MMU recommends removal of all references to and reliance on the FERC System of Accounts in PJM Manual 15.

Cyclic Starting and Peaking Factors

The use of cyclic starting and peaking factors for calculating VOM costs for combined cycles and combustion turbines is designed to allocate a greater proportion of long term maintenance costs to starts and the tail block of the incremental offer curve. The use of such factors is not appropriate given that long term maintenance costs are not short run marginal costs and should not be included in cost offers. PJM Manual 15 allows for a peaking cyclic factor of three, which means that a unit with a $300 per hour (EOH) VOM cost can add $180 per MWh to a 5 MW peak segment.[220]

The MMU recommends the removal of all cyclic starting and peaking factors from PJM Manual 15.

Labor Costs

PJM Manual 15 allows for the inclusion of plant staffing costs in energy market cost offers. This is inappropriate given that labor costs are not short run marginal costs.

The MMU recommends the removal of all labor costs from the PJM Manual 15. On December 2, 2022, PJM filed tariff changes removing labor costs from

220 The peak adder is equal to $300 times three divided by 5 MW.

cost-based offers. The changes were approved by the Commission on January 10, 2023 and became effective on June 1, 2023.[221]

Combined Cycle Start Heat Input Definition

PJM Manual 15 defines the start heat input of combined cycles as the amount of fuel used from the firing of the first combustion turbine to the close of the steam turbine breaker plus any fuel used by other combustion turbines in the combined cycle from firing to the point at which the HRSG steam pressure matches the steam turbine steam pressure. This definition is inappropriate given that after each combustion turbine is synchronized, some of the fuel is used to produce energy for which the unit is compensated in the energy market. To account for this, PJM Manual 15 requires reducing the station service MWh used during the start sequence by the output in MWh produced by each combustion turbine after synchronization and before the HRSG steam pressure matches the steam turbine steam pressure. The formula and the language in this definition are not appropriate and are unclear.

The MMU recommended changing the definition of the start heat input for combined cycles to include only the amount of fuel used from firing each combustion turbine in the combined cycle to the breaker close of each combustion turbine. This change will make the treatment of combined cycles consistent with steam turbines. Exceptions to this definition should be granted when the amount of fuel used from synchronization to steam turbine breaker close is greater than the no load heat plus the output during this period times the incremental heat rate.

In 2022, the MMU and PJM proposed changing the start cost definition of units with a steam process to include the costs from the beginning of the start sequence to dispatchable.[222] The new definition included what is commonly consider soak costs in the start cost. The new definition was combined with the elimination of make whole payments to units with a steam process for MW produced before the unit becomes dispatchable. The proposal was approved by the Commission on January 10, 2023 and became effective on June 1, 2023.[223]

221 *See* Federal Energy Regulatory Commission, Docket No. ER23-557-000 (January 10, 2023) at 1.
222 *See* "Start Cost Alternate Proposal," MMU presentation to the Cost Development Subcommittee. (December 2, 2021) <20211202-item-06-start-cost-alternate-proposal.ashx>.
223 *See* Federal Energy Regulatory Commission, Docket No. ER23-557-000 (January 10, 2023) at 1.

Even though the MMU developed and supported the new definition, it is important to recognize that this approach should be temporary until PJM implements an approach that reflects soak time, soak costs and soak energy output. The main shortcoming of the new definition is that PJM models do not properly value the energy produced during the soak process (soak energy output). Instead, the proposal simply assumes that such MWh are valued at PJM's station service rate. The ideal solution is to model start costs and soak costs separately since there are revenues associated with the MWh produced during soaking, while during the start process there are no MWh being injected into the grid.

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.

Nuclear Costs

The fuel costs for nuclear plants are fixed in the short run and amortized over the period between refueling outages. The short run marginal cost of fuel for nuclear plants is zero. Operations and maintenance costs for nuclear power plants consist primarily of labor and maintenance costs incurred during outages, which are also fixed in the short run.

The MMU recommends the removal of nuclear fuel and nonfuel operations and maintenance costs that are not short run marginal costs from the PJM Manual 15.

Pumped Hydro Costs

The calculation of pumped hydro costs for energy storage in Section 7.3 of PJM Manual 15 is inaccurate. The mathematical formulation does not take into account the purchase of power for pumping in the day-ahead market.

The MMU recommends revising the pumped hydro fuel cost calculation to include day-ahead and real-time power purchases.

Gas Pipeline Penalties

Section 2.2.2 of PJM Manual 15 states that gas pipeline penalties are not includable in cost-based offers. Penalties can be incurred by units for many reasons, for example, withdrawing gas not nominated and deviating from an imposed threshold during an operational flow order. Any unit with cost-based offers that include gas pipeline penalties will be subject to penalties per Schedule 2 of the PJM Operating Agreement.

Many Market Sellers rely on independent third party quotes to estimate or determine the gas spot price. The quotes received from these third parties should not be based on incurring gas pipeline penalties. It is recommended that Market Sellers confirm with their third parties that gas is available to them without the need to incur gas pipeline penalties. If that is not possible, the units should be unavailable until the third party can confirm that gas is available without incurring penalties.

Frequently Mitigated Units (FMU) and Associated Units (AU)

The rules for determining the qualification of a unit as an FMU or AU became effective November 1, 2014. The number of units that were eligible for an FMU or AU adder declined from an average of 70 units during the first 11 months of 2014, to zero units eligible for an FMU or AU adder for the period between December 2014 and August 2019.[224] One unit qualified for an FMU adder for the months of September and October, 2019. In 2020, five units qualified for an FMU adder in at least one month. In 2021, one unit qualified for an FMU adder in January. In 2022, 2023, 2024 and 2025 no units qualified for an FMU adder. In the first three months of 2026, no units qualified for an FMU adder

Table 3-130 shows, by month, the number of FMUs and AUs from January 2021 through March 2026. For example, in January 2021, there were zero units that qualified as an FMU or AU in Tier 1, one unit qualified as an FMU or AU in Tier 2, and zero units qualified as an FMU or AU in Tier 3.

Table 3-130 Number of frequently mitigated units and associated units (By month): January 2021 through March 2026

	2021				2022				2023				2024				2025				2026			
	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder
January	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
February	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
March	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
April	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0				
May	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0				
June	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0				
July	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0				
August	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0				
September	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0				
October	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0				
November	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0				
December	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0				

224 For a definition of FMUs and AUs, and for historical FMU/AU results, see the ***2018 Annual State of the Market Report for PJM***, Volume 2, Section 3, Energy Market, at Frequently Mitigated Units (FMU) and Associated Units (AU).

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.

Market Performance

Ownership of Marginal Resources

Table 3-131 shows the contribution to real-time, load-weighted LMP by individual marginal resource owners.[225] The contribution of each marginal resource to price at each load bus is calculated for each five minute interval of first three months of 2026, and summed by the parent company that offers the marginal resource into the real-time energy market. In the first three months of 2026, the offers of one company resulted in 10.8 percent of the real-time load-weighted PJM system LMP and the offers of the top four companies resulted in 35.3 percent of the real-time load-weighted average PJM system LMP. In the first three month of 2026, the offers of one company resulted in 15.1 percent of the peak hour real-time load-weighted PJM system LMP.

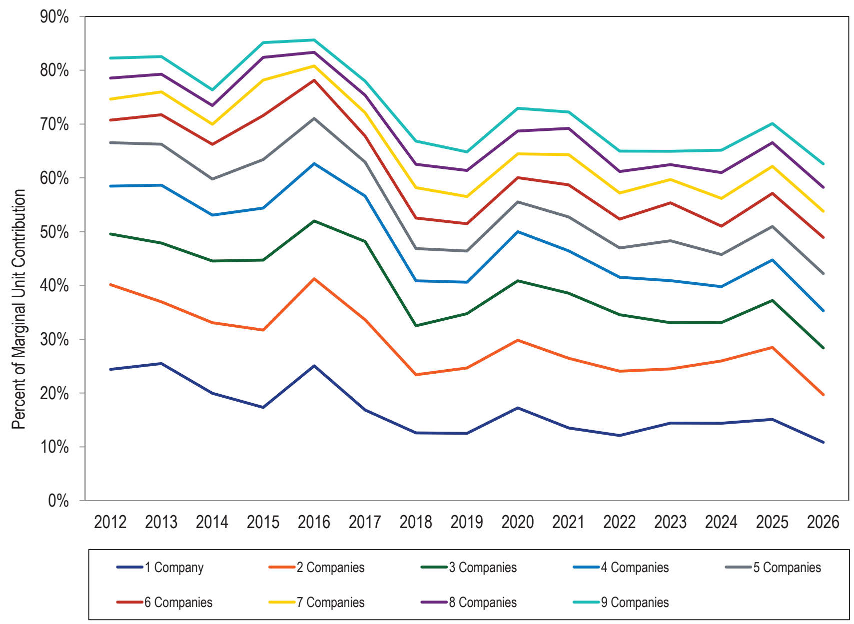
Table 3-131 Marginal unit contribution to real-time load-weighted LMP (By parent company): January through March, 2025 and 2026

2025 (Jan - Mar)						2026 (Jan - Mar)					
All Hours			Peak Hours			All Hours			Peak Hours		
Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent
1	15.1%	15.1%	1	14.1%	14.1%	1	10.8%	10.8%	1	9.4%	9.4%
2	13.4%	28.5%	2	12.5%	26.6%	2	8.9%	19.7%	2	9.2%	18.5%
3	8.7%	37.2%	3	9.6%	36.2%	3	8.7%	28.4%	3	8.6%	27.2%
4	7.5%	44.7%	4	8.0%	44.2%	4	6.9%	35.3%	4	7.3%	34.5%
5	6.2%	51.0%	5	5.6%	49.8%	5	6.9%	42.2%	5	7.1%	41.6%
6	6.2%	57.1%	6	5.3%	55.1%	6	6.7%	48.9%	6	5.4%	47.0%
7	5.0%	62.1%	7	5.3%	60.4%	7	4.9%	53.8%	7	5.2%	52.2%
8	4.4%	66.5%	8	5.1%	65.5%	8	4.4%	58.2%	8	4.5%	56.7%
9	3.6%	70.1%	9	3.1%	68.6%	9	4.4%	62.6%	9	4.2%	60.8%
Other (86 companies)	29.9%	100.0%	Other (83 companies)	31.4%	100.0%	Other (86 companies)	37.4%	100.0%	Other (85 companies)	39.2%	100.0%

225 See the *MMU Technical Reference for PJM Markets*, at "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

Figure 3-73 shows the marginal unit contribution to the real-time load-weighted PJM system LMP summed by parent companies for the first three months of every year since 2012.

Figure 3-73 Marginal unit contribution to real-time load-weighted LMP (By parent company): January through March, 2012 through 2026



Markup

The markup index is a measure of the competitiveness of participant behavior for individual units. The markup in dollars is a measure of the impact of participant behavior on the generator bus market price when a unit is marginal. As an example, if unit A has a $90 cost and a $100 price, while unit B has a $9 cost and a $10 price, both would show a markup index of 10 percent, but the price impact of unit A's markup at the generator bus would be $10 while the price impact of unit B's markup at the generator bus would be $1. Depending on each unit's location on the transmission system, those bus level impacts could also have different impacts on total system price. Markup can also affect prices when units with markups are not marginal by altering the economic dispatch order of supply.

The MMU calculates an explicit measure of the impact of marginal unit incremental energy offer markups on LMP using the mathematical relationships among LMPs in the market solution.[226] The markup impact calculation sums, over all marginal units, the product of the dollar markup of the unit and the marginal impact of the unit's offer on the system load-weighted LMP. The markup impact includes the impact of the identified markup behavior of all marginal units. Positive and negative markup impacts may offset one another. The markup analysis is a direct measure of market performance. It does not take into account whether or not marginal units have either locational or aggregate structural market power.

The markup calculation is not based on a counterfactual redispatch of the system to determine the marginal units and their marginal costs that would have occurred if all units had made all offers at short run marginal cost. A full redispatch analysis is practically impossible and a limited redispatch analysis would not be dispositive. Nonetheless, such a hypothetical counterfactual analysis would reveal the extent to which the actual system dispatch is less than competitive if it showed a difference between dispatch based on short run marginal cost and actual dispatch. It is possible that the unit specific markup, based on a redispatch analysis, would be lower than the markup component of price if the reference point were an inframarginal unit with a lower price and a higher cost than the actual marginal unit. If the actual marginal unit has short run marginal costs that would cause it to be inframarginal, a new unit would be marginal. If the offer of that new unit were greater than the cost of the original marginal unit, the markup impact would be lower than the MMU measure. If the newly marginal unit is on a price-based schedule, the analysis would have to capture the markup impact of that unit as well.

226 The MMU calculates the impact on system prices of marginal unit price-cost markup, based on analysis using sensitivity factors. The calculation shows the markup component of LMP based on a comparison between the price-based incremental energy offer and the cost-based incremental energy offer of each actual marginal unit on the system. This is the same method used to calculate the fuel cost adjusted LMP and the components of LMP. *See* Calculation and Use of Generator Sensitivity/Unit Participation Factors, 2010 State of the Market Report for PJM: Technical Reference for PJM Markets.

Real-Time Markup

Markup Component of Real-Time Price by Fuel, Unit Type

The markup component of price is the difference between the system price, when the system price is determined by the active offers of the marginal units, whether price or cost-based, and the system price, based on the cost-based offers of those marginal units.

PJM implemented fast start pricing on September 1, 2021. Under the fast start pricing rules, the LMPs are calculated in the pricing run, where the offer price of a marginal fast start unit includes amortized commitment costs. For all the fast start marginal units starting from September 1, 2021, the markup includes markup in the incremental offer, markup in the amortized start up offer and markup in the amortized no load offer.

Table 3-132 shows the impact (markup component of LMP) of the marginal unit markup behavior by fuel type and unit type on the real-time load-weighted average system LMP using unadjusted and adjusted offers. The adjusted markup component of LMP increased from $0.56 per MWh in the first three months of 2025 to $5.41 per MWh in the first three months of 2026. The adjusted markup contribution of coal units in the first three months of 2026 was $1.35 per MWh, an increase of $0.79 per MWh from the first three months of 2025. The adjusted markup component of gas fired units in the first three months of 2026 was $3.36 per MWh, an increase of $1.14 per MWh from the first three months of 2025. The markup component of wind units was $0.38 per MWh. If a price-based offer is negative, but less negative than a cost-based offer, the markup is positive. In the first three months of 2026, among the wind units that were marginal, 75.7 percent had negative offer prices.

Table 3-132 Markup component of real-time load-weighted average LMP by primary fuel type and unit type: January through March, 2025 and 2026[227]

		2025 (Jan - Mar)		2026 (Jan - Mar)	
Fuel	Technology	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)
Coal	Steam	$0.09	$0.56	$0.82	$1.35
Gas	CC	($0.42)	$1.65	($0.33)	$2.32
Gas	CT	$0.00	$0.56	$0.03	$1.06
Gas	RICE	$0.02	$0.03	($0.04)	($0.00)
Gas	Steam	($0.13)	($0.03)	($0.18)	($0.03)
Municipal Waste	RICE	$0.02	$0.02	$0.02	$0.02
Oil	CC	($0.01)	$0.02	$0.01	$0.02
Oil	CT	($0.52)	($0.28)	($0.28)	$0.17
Oil	RICE	$0.00	$0.00	($0.00)	$0.01
Oil	Steam	($0.02)	$0.00	$0.01	$0.05
Other	Solar	$0.01	$0.01	$0.16	$0.16
Other	Steam	$0.00	$0.00	$0.00	($0.05)
Wind	Wind	$0.01	$0.01	$0.38	$0.38
Total		($0.95)	$2.58	$0.56	$5.41

Markup Component of Real-Time Price

Table 3-133 shows the markup component, calculated using unadjusted offers, of average prices and of average monthly on peak and off peak prices. Table 3-134 shows the markup component, calculated using adjusted offers, of average prices and of average monthly on peak and off peak prices. In the first three months of 2026, when using unadjusted cost-based offers, $0.56 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. Using adjusted cost-based offers, $5.41 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. In the first three months of 2026, the peak markup component was highest in February, $4.16 per MWh using unadjusted cost-based offers and $8.25 per MWh using adjusted cost-based offers. This corresponds to 5.2 percent and 10.3 percent of the real-time peak load weighted average LMP in February.

227 The unit type RICE refers to Reciprocating Internal Combustion Engines.

Table 3-133 Monthly markup components of real-time load-weighted LMP (Unadjusted): January 2025 through March 2026

	2025			2026		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	($2.00)	($1.17)	($2.83)	($3.80)	($6.96)	($1.03)
Feb	($0.22)	($0.59)	$0.15	$5.04	$4.16	$5.88
Mar	($0.37)	($1.02)	$0.22	$1.11	$0.73	$1.50
Apr	$0.68	$0.32	$1.07			
May	($0.54)	($0.29)	($0.79)			
Jun	$0.29	($0.08)	$0.69			
Jul	$0.55	$2.74	($1.87)			
Aug	($0.91)	($0.94)	($0.87)			
Sep	$1.52	$1.48	$1.56			
Oct	$1.69	$2.28	$1.04			
Nov	($1.06)	($2.04)	($0.26)			
Dec	($1.40)	($1.31)	($1.49)			
Total	($0.16)	$0.01	($0.40)	$0.56	($0.91)	$1.94

Table 3-134 Monthly markup components of real-time load-weighted LMP (Adjusted): January 2025 through March 2026

	2025			2026		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	$2.16	$3.38	$0.95	$3.32	($0.24)	$6.45
Feb	$3.21	$3.08	$3.35	$9.50	$8.25	$10.70
Mar	$2.40	$1.79	$2.94	$3.59	$3.41	$3.77
Apr	$3.53	$3.24	$3.85			
May	$1.68	$2.16	$1.20			
Jun	$3.34	$3.47	$3.21			
Jul	$4.01	$6.66	$1.08			
Aug	$1.72	$2.08	$1.37			
Sep	$3.86	$4.05	$3.66			
Oct	$4.56	$5.42	$3.59			
Nov	$2.13	$1.50	$2.64			
Dec	$2.23	$2.49	$1.96			
Total	$2.94	$3.39	$2.40	$5.41	$3.68	$7.04

Hourly Markup Component of Real-Time Prices

Figure 3-74 shows the markup contribution to the hourly load-weighted LMP using unadjusted cost offers in 2025 and the first three months of 2026. Figure 3-75 shows the markup contribution to the hourly load-weighted LMP using adjusted cost-based offers in 2025 and the first three months of 2026.

Figure 3-74 Markup contribution to real-time hourly load-weighted LMP (Unadjusted): January 2025 through March 2026

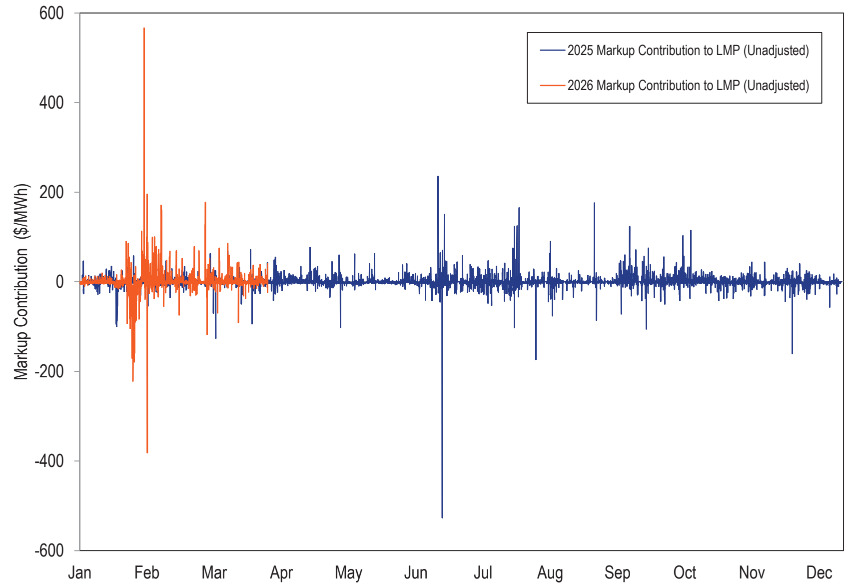
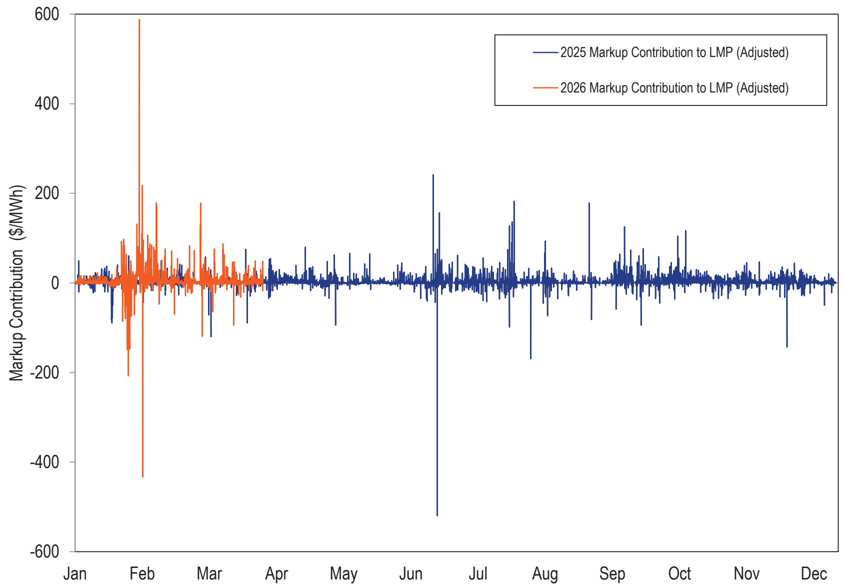


Figure 3-75 Markup contribution to real-time hourly load-weighted LMP (Adjusted): January 2025 through March 2026



Markup Component of Real-Time Zonal Prices

The unit markup component of average real-time price using unadjusted offers is shown for each zone in the first three months of 2025 and 2026 in Table 3-135 and for adjusted offers in Table 3-136.[228] The smallest zonal all hours average markup component using unadjusted offers in the first three months of 2026, was in the PECO Zone, -$1.32 per MWh, while the highest was in the PEPCO Zone, $2.80 per MWh. The smallest zonal on peak average markup component using unadjusted offers in the first three months of 2026, was in the PECO Zone, -$2.62 per MWh, while the highest was in the BGE Zone, $0.66 per MWh.

Table 3-135 Real-time average zonal markup component (Unadjusted): January through March, 2025 and 2026

	2025 (Jan - Mar)			2026 (Jan - Mar)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
ACEC	($1.29)	($1.34)	($1.25)	($1.14)	($2.55)	$0.19
AEP	($1.01)	($0.94)	($1.07)	$0.08	($1.02)	$1.12
APS	($0.91)	($0.82)	($1.00)	$0.83	($0.61)	$2.18
ATSI	($1.13)	($1.04)	($1.21)	($0.50)	($1.55)	$0.49
BGE	($0.54)	($0.51)	($0.56)	$2.62	$0.66	$4.46
COMED	($1.47)	($1.66)	($1.28)	$0.89	($0.50)	$2.20
DAY	($1.28)	($1.35)	($1.22)	$0.20	($1.01)	$1.35
DOM	($0.46)	($0.52)	($0.40)	$2.19	($0.19)	$4.44
DPL	($1.17)	($0.98)	($1.35)	($1.32)	($2.58)	($0.13)
DUKE	($1.32)	($1.45)	($1.20)	$0.18	($1.08)	$1.36
DUQ	($1.09)	($0.89)	($1.28)	($0.86)	($1.68)	($0.09)
EKPC	($1.12)	($1.21)	($1.03)	$0.30	($0.91)	$1.45
JCPLC	($1.07)	($1.13)	($1.02)	($0.82)	($2.16)	$0.44
MEC	($1.02)	($0.86)	($1.16)	($0.69)	($1.81)	$0.36
OVEC	($1.06)	($0.84)	($1.27)	$0.30	($0.69)	$1.24
PE	($0.07)	($0.01)	($0.13)	($0.36)	($0.77)	$0.02
PECO	($1.01)	($0.74)	($1.27)	($1.32)	($2.62)	($0.10)
PEPCO	($0.50)	($0.60)	($0.41)	$2.80	$0.49	$4.97
PPL	($1.34)	($1.04)	($1.62)	($0.30)	($0.87)	$0.23
PSEG	($0.90)	($0.90)	($0.91)	($0.49)	($1.82)	$0.77
REC	($0.24)	($0.47)	($0.03)	$0.23	($0.12)	$0.57

228 A marginal unit's offer price affects LMPs in the entire PJM market. The markup component of average zonal real-time price is based on offers of units located within the zone and units located outside the transmission zone.

Table 3-136 Real-time average zonal markup component (Adjusted): January through March, 2025 and 2026

	2025 (Jan - Mar)			2026 (Jan - Mar)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
ACEC	$2.10	$2.34	$1.87	$3.84	$2.09	$5.49
AEP	$2.44	$2.69	$2.20	$4.46	$3.25	$5.59
APS	$2.72	$3.05	$2.41	$6.03	$4.31	$7.64
ATSI	$2.27	$2.58	$1.98	$3.72	$2.70	$4.68
BGE	$3.57	$3.92	$3.23	$8.66	$6.18	$11.00
COMED	$1.30	$1.39	$1.21	$4.02	$2.62	$5.35
DAY	$2.10	$2.24	$1.95	$4.57	$3.35	$5.72
DOM	$3.57	$3.80	$3.35	$8.22	$5.25	$11.01
DPL	$2.33	$2.80	$1.88	$4.01	$2.22	$5.71
DUKE	$1.92	$1.99	$1.86	$4.45	$3.21	$5.63
DUQ	$2.26	$2.66	$1.88	$3.33	$2.48	$4.14
EKPC	$2.24	$2.30	$2.19	$4.58	$3.27	$5.83
JCPLC	$2.37	$2.61	$2.14	$4.18	$2.58	$5.69
MEC	$2.45	$2.93	$1.99	$4.44	$2.99	$5.81
OVEC	$2.06	$2.46	$1.67	$4.44	$3.40	$5.42
PE	$3.54	$3.86	$3.23	$4.28	$3.84	$4.71
PECO	$2.31	$2.86	$1.79	$3.59	$1.95	$5.14
PEPCO	$3.53	$3.73	$3.34	$8.94	$6.07	$11.65
PPL	$2.05	$2.68	$1.44	$4.58	$3.77	$5.34
PSEG	$2.60	$2.92	$2.30	$4.58	$3.08	$5.99
REC	$3.39	$3.45	$3.34	$5.34	$5.05	$5.61

Markup by Real-Time Price Levels

Table 3-137 shows the markup contribution to the LMP, based on the unadjusted cost-based offers and adjusted cost-based offers of the marginal units, when the PJM system wide load-weighted average LMP was in the identified price range.

Table 3-137 Real-time markup contribution (By load-weighted LMP category, unadjusted): January through March, 2025 and 2026

	2025 (Jan - Mar)		2026 (Jan - Mar)	
LMP Category	Markup Component	Frequency	Markup Component	Frequency
< $10	$0.00	0.0%	($2.65)	0.1%
$10 to $15	$0.00	0.0%	($1.04)	1.4%
$15 to $20	($2.37)	1.3%	($1.11)	5.4%
$20 to $25	($2.13)	6.8%	($2.27)	10.0%
$25 to $50	($1.91)	63.2%	($1.23)	48.1%
$50 to $75	$0.19	16.8%	$0.22	11.9%
$75 to $100	$0.51	5.6%	$0.54	4.4%
$100 to $125	$6.16	2.3%	$6.70	3.3%
$125 to $150	$2.87	1.5%	$4.24	2.4%
>= $150	$2.56	2.5%	$6.03	13.1%

Table 3-138 Real-time markup contribution (By load-weighted LMP category, adjusted): January through March, 2025 and 2026

	2025 (Jan - Mar)		2026 (Jan - Mar)	
LMP Category	Markup Component	Frequency	Markup Component	Frequency
< $10	$0.00	0.0%	($1.44)	0.1%
$10 to $15	$0.00	0.0%	$0.29	1.4%
$15 to $20	($0.70)	1.3%	$0.42	5.4%
$20 to $25	($0.22)	6.8%	($0.33)	10.0%
$25 to $50	$0.91	63.2%	$1.47	48.1%
$50 to $75	$3.93	16.8%	$4.08	11.9%
$75 to $100	$5.35	5.6%	$4.90	4.4%
$100 to $125	$12.10	2.3%	$12.65	3.3%
$125 to $150	$11.36	1.5%	$11.34	2.4%
>= $150	$13.87	2.5%	$20.08	13.1%

Markup by Company

Table 3-139 shows the markup contribution based on the unadjusted cost-based offers and adjusted cost-based offers to real-time load-weighted average LMP by individual marginal resource owners. The markup contribution of each marginal resource to price at each load bus is calculated for each five-minute interval, and summed by the parent company that offers the marginal resource into the real-time energy market. In the first three months of 2026, when using unadjusted cost-based offers, the markup of one company accounted for 0.7 percent of the load-weighted average LMP, the markup of the top five companies accounted for 2.5 percent of the load-weighted average

LMP and the markup of all companies accounted for 0.6 percent of the load-weighted average LMP. The share of top five companies' markup contribution to the load-weighted average LMP and the dollar values of their markup increased in the first three months of 2026. The markup contribution to the load-weighted average LMP decreased and share of the markup contribution to the load-weighted average LMP increased in the first three months of 2026. The markup contribution of a unit to the real-time load-weighted average LMP can be positive or negative.

Table 3-139 Markup component of real-time load-weighted average LMP by Company: January through March, 2025 and 2026

	2025 (Jan - Mar)				2026 (Jan - Mar)			
	Markup Component of LMP (Unadjusted)		Markup Component of LMP (Adjusted)		Markup Component of LMP (Unadjusted)		Markup Component of LMP (Adjusted)	
	$/MWh	Percent of Load Weighted LMP	$/MWh	Percent of Load Weighted LMP	$/MWh	Percent of Load Weighted LMP	$/MWh	Percent of Load Weighted LMP
Top 1 Company	$0.35	0.7%	$0.78	1.5%	$0.62	0.7%	$0.89	1.0%
Top 2 Companies	$0.52	1.0%	$1.17	2.2%	$1.04	1.2%	$1.60	1.8%
Top 3 Companies	$0.69	1.3%	$1.44	2.7%	$1.45	1.7%	$2.18	2.5%
Top 4 Companies	$0.85	1.6%	$1.68	3.2%	$1.80	2.1%	$2.76	3.1%
Top 5 Companies	$0.97	1.9%	$1.93	3.7%	$2.15	2.5%	$3.16	3.6%
All Companies	($0.95)	(1.8%)	$2.57	4.9%	$0.55	0.6%	$5.46	6.2%

Day-Ahead Markup[229]

Markup Component of Day-Ahead Price by Fuel, Unit Type

The markup component of the PJM day-ahead load-weighted average LMP by primary fuel and unit type is shown in Table 3-140. INC, DEC and up to congestion transactions (UTC) have zero markups. The adjusted markup of coal, gas and oil units is calculated as the difference between the price-based offer and the cost-based offer excluding the 10 percent adder.

Table 3-140 shows the markup component of LMP for marginal generating resources. The adjusted markup component of LMP for coal fired units was $0.90 per MWh in the first three months of 2026. The adjusted markup component of LMP for gas fired CC units was $1.82 per MWh in the first three months of 2026.

229 The MMU identified an error in the marginal resource identification algorithm within the day ahead clearing optimization. The calculation of generator sensitivity factors and markup index require accurate identification of marginal resources. The error was fixed by the PJM software vendor in March 2025. MMU was unable to calculate markup index for 2024 and the first quarter of 2025 due to the inaccurate identification of marginal resources.

Table 3-140 Markup component of day-ahead load-weighted average LMP by primary fuel type and technology type: January through March, 2026

		2026 (Jan - Mar)		2026 (Jan - Mar)	
Fuel	Technology	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)
Coal	Steam	$0.18	$0.90	$0.00	$0.00
Gas	CC	($0.20)	$1.73	$0.00	$0.00
Gas	CT	$0.33	$0.16	$0.00	$0.00
Gas	RICE	($0.02)	$0.01	$0.00	$0.00
Gas	Steam	($0.25)	($0.08)	$0.00	$0.00
Oil	CT	($0.00)	$0.16	$0.00	$0.00
Oil	RICE	$0.00	$0.02	$0.00	$0.00
Oil	Steam	($0.00)	$0.00	$0.00	$0.00
Other	Solar	$0.20	$0.20	$0.00	$0.00
Other	Steam	($0.01)	($0.01)	$0.00	$0.00
Wind	Wind	$1.16	$1.16	$0.00	$0.00
Total		$1.38	$4.25	$0.00	$0.00

Markup Component of Day-Ahead Price

The markup component of price is the difference between the system price, when the system price is determined by the active offers of the marginal units, whether price or cost-based, and the system price, based on the cost-based offers of those marginal units. Only hours when generating units were marginal on either priced-based offers or on cost-based offers were included in the markup calculation.

Table 3-141 shows the markup component of average prices and of average monthly on peak and off peak prices using unadjusted cost-based offers. Table 3-142 shows the markup component of average prices and of average monthly on peak and off peak prices using adjusted cost-based offers. In the first three months of 2026, when using unadjusted cost-based offers, $1.38 per MWh of the PJM day-ahead load-weighted average LMP was attributable to markup. Using adjusted cost-based offers, $4.25 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. In the first three months of 2026, the peak markup component was highest in January, $5.37 per MWh using unadjusted cost-based offers and $9.33 per MWh using adjusted cost-based offers. This corresponds to 3.3 percent and 5.7 percent of the day-ahead peak load weighted average LMP in January.

Table 3-141 Monthly markup components of day-ahead (Unadjusted) load-weighted LMP: January 2026 through March 2026

	2026		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	$3.39	$5.37	$1.64
Feb	$1.30	$0.02	$2.54
Mar	($0.98)	$2.28	($4.31)
Total	$1.38	$2.65	$0.17

Table 3-142 Monthly markup components of day-ahead (Adjusted) load-weighted LMP: January 2026 through March 2026

	2026		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	$7.76	$9.33	$6.36
Feb	$3.51	$2.01	$4.95
Mar	$0.76	$3.49	($2.03)
Total	$4.25	$5.10	$3.43

Markup Component of Day-Ahead Zonal Prices

Table 3-143 shows the markup component of annual average day-ahead price using unadjusted cost-based offers for each zone and for adjusted offers in Table 3-144.

The smallest zonal all hours average markup component using unadjusted cost-based offers for the first three months of 2026 was in PPL, -$2.78 per MWh, while the highest was in DAY, $6.70 per MWh. The smallest zonal on peak average markup using unadjusted cost-based offers was in PPL, -$2.85 per MWh, while the highest was in DAY, $9.95 per MWh.

Table 3-143 Day-ahead average zonal markup component (Unadjusted): January through March, 2026

	2026 (Jan - Mar)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
ACEC	($0.01)	$3.36	($3.15)
AEP	$5.31	$9.55	$1.35
APS	$2.65	$5.41	$0.05
ATSI	$5.75	$6.82	$4.75
BGE	$0.77	$0.08	$1.41
COMED	$0.68	$4.14	($2.58)
DAY	$6.70	$9.95	$3.67
DOM	$0.29	$0.70	($0.09)
DPL	($2.61)	($1.61)	($3.55)
DUKE	$4.70	$6.44	$3.07
DUQ	$5.73	$8.25	$3.37
EKPC	$4.95	$8.45	$1.67
JCPLC	($1.39)	($0.26)	($2.45)
MEC	($1.04)	$0.09	($2.09)
OVEC	($1.83)	($2.27)	($1.35)
PE	$2.63	$1.83	$3.37
PECO	$0.40	$3.64	($2.63)
PEPCO	($0.08)	$0.68	($0.79)
PPL	($2.78)	($2.85)	($2.72)
PSEG	($2.28)	($2.78)	($1.80)
REC	$1.47	$2.98	$0.07

Table 3-144 Day-ahead average zonal markup component (Adjusted): January through March, 2026

	2026 (Jan - Mar)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
ACEC	$4.01	$7.03	$1.17
AEP	$7.37	$10.36	$4.56
APS	$5.94	$7.95	$4.05
ATSI	$8.21	$7.94	$8.45
BGE	$5.02	$4.42	$5.58
COMED	$2.62	$5.92	($0.51)
DAY	$8.86	$10.56	$7.26
DOM	$4.34	$4.63	$4.06
DPL	$1.25	$1.92	$0.61
DUKE	$7.75	$8.89	$6.68
DUQ	$8.36	$9.69	$7.10
EKPC	$8.24	$11.27	$5.39
JCPLC	$2.67	$3.50	$1.89
MEC	$3.26	$4.14	$2.44
OVEC	$0.91	$0.97	$0.85
PE	$6.16	$4.13	$8.08
PECO	$4.59	$7.46	$1.89
PEPCO	$4.04	$5.00	$3.13
PPL	$1.76	$1.70	$1.81
PSEG	$1.93	$1.25	$2.57
REC	$5.50	$6.57	$4.49

Markup by Day-Ahead Price Levels

Table 3-145 and Table 3-146 show the average markup component of LMP, based on the unadjusted cost-based offers and adjusted cost-based offers of the marginal units, when the PJM system LMP was in the identified price range.

Table 3-145 Day-ahead average markup component (By LMP category, unadjusted): January through March, 2026

	2026 (Jan - Mar)	
LMP Category	Markup Component	Frequency
$15 to $20	($1.34)	1.5%
$20 to $25	($0.13)	6.7%
$25 to $50	($1.95)	57.7%
$50 to $75	$0.89	12.5%
$75 to $100	($0.69)	4.1%
$100 to $125	$5.61	2.1%
$125 to $150	($2.77)	2.2%
>= $150	$14.46	13.2%

Table 3-146 Day-ahead average markup component (By LMP category, adjusted): January through March, 2026

	2026 (Jan - Mar)	
LMP Category	Markup Component	Frequency
$15 to $20	($0.17)	1.5%
$20 to $25	$1.16	6.7%
$25 to $50	($0.09)	57.7%
$50 to $75	$2.72	12.5%
$75 to $100	$0.62	4.1%
$100 to $125	$7.81	2.1%
$125 to $150	$0.48	2.2%
>= $150	$22.73	13.2%

Market Structure, Participant Behavior, and Market Performance

The goal of regulation through competition is to achieve competitive market outcomes even in the presence of market power. Market structure in the PJM energy market is not competitive in local markets created by transmission constraints. At times, market structure is not competitive in the aggregate energy market. Market sellers pursuing their financial interests may choose behavior that benefits from structural market power in the absence of an effective market power mitigation program. The overall competitive assessment evaluates the extent to which participant behavior results in competitive or above competitive pricing. The competitive assessment brings together the structural measures of market power, HHI and pivotal suppliers, with participant behavior, specifically markup, and pricing outcomes.

HHI and Markup

In theory, the HHI provides insight into the relationship between market structure, behavior, and performance. In the case where participants compete by producing output at constant, but potentially different, marginal costs, the HHI is directly proportional to the expected average price cost markup in the market:[230]

$$\frac{HHI}{\varepsilon} = \frac{P - MC}{P}$$

where ε is the absolute value of the price elasticity of demand, *P* is the market price, and *MC* is the average marginal cost of production. This is called the Lerner Index. The left side of the equation quantifies market structure, and the right side of the equation measures market performance. The assumed participant behavior is profit maximization. As HHI decreases, implying a more competitive market, prices converge to marginal cost, the competitive market outcome. But even a low HHI may result in substantial markup with a low price elasticity of demand. If HHI is very high, meaning competition is lacking, prices can reach the monopoly level. Price elasticity of demand (ε) determines the degree to which suppliers with market power can impose higher prices on customers. The Lerner Index is a measure of market power that connects market structure (HHI and demand elasticity) to market performance (markup).

The PJM energy market HHIs and application of the FERC concentration categories understate the degree of market power because, in the absence of aggregate market power mitigation, even the unconcentrated HHI level implies substantial markups due to the low short run price elasticity of demand. For example, research estimates find short run electricity demand elasticity ranging from -0.2 to -0.4.[231] Using the Lerner Index, the elasticity of -0.2 implies, for example, an average markup ranging from 25 to 50 percent at the low end of the moderately concentrated threshold HHI of 1000:[232]

$$\frac{HHI}{\varepsilon} = \frac{0.1}{0.2} = \frac{P - MC}{P} = 0.5$$

With knowledge of HHI, elasticity, and marginal cost, one can solve for the price level theoretically indicated by the Lerner Index, based on profit maximizing behavior including the exercise of market power. With marginal costs of $87.02 per MWh and an average HHI of 753 in the first three months of 2026, average PJM prices would theoretically range from $107 to $140 per MWh, an implied markup of 18.8 to 37.7 percent, using the elasticity range of -0.2 to -0.4. Given the elasticity estimates, the theoretical prices exceed marginal costs because the exercise of market power is profit maximizing. In the PJM market, market power mitigation limits the exercise of market power, so prices cannot reach the higher theoretical level. Actual prices, averaging $87.57 per MWh with markups at 0.6 percent, are lower than the theoretical range, supporting the MMU's competitive assessment of the market. However, markup is not zero. In some market intervals, markup and prices reach levels that reflect the exercise of market power.

Aggregate Market Power and Markup

The HHI is not the only test for market power in the aggregate market. The determination of the existence of pivotal suppliers is a better measure than HHI of whether a resource has market power in the PJM aggregate energy market. Table 3-147 compares the markup by marginal resources in the energy market for pivotal suppliers in the day-ahead market to all other suppliers. The results show that when a company is one of three pivotal suppliers in the day-ahead energy market, it is more likely to set price with a positive markup. In the first three months of 2026, 13.0 percent of day-ahead marginal units and 7.4 percent of real-time marginal units set price with a positive markup when they were one of three day-ahead pivotal suppliers for the day. Of those, 40 marginal unit hours in the day-ahead market and 296 marginal unit intervals in the real-time market had markups over $100 per MWh. Only 9.8 percent

230 *See* Tirole, Jean. *The Theory of Industrial Organization*, MIT (1988), Chapter 5: Short-Run Price Competition.

231 See Patrick, Robert H. and Frank A. Wolak (1997), "Estimating the Customer-Level Demand for Electricity Under Real-Time Market Prices," <https://web.stanford.edu/group/fwolak/cgi-bin/sites/default/files/files/Estimating%20the%20Customer-Level%20Demand%20for%20Electricity%20Under%20Real-Time%20Market%20Prices_Aug%201997_Patrick,%20Wolak.pdf>, last accessed August 3, 2018 and Fan, Shu and Rob Hyndman (2010), "The price elasticity of electricity demand in South Australia," <https://robjhyndman.com/papers/Elasticity2010.pdf>.

232 The HHI used in the equation is based on market shares. For the FERC HHI thresholds and standard HHI reporting, market shares are multiplied by 100 prior to squaring the market shares.

of day-ahead and 4.9 percent of real-time marginal units set price with a positive markup when they were not one of three pivotal suppliers.

Table 3-147 Percent of marginal unit intervals with markup and local market power: January through March, 2026

	Day-ahead Market			Real-time Market		
Markup Category	Not TPS Aggregate	TPS Aggregate	Percent in Category	Not TPS Aggregate	TPS Aggregate	Percent in Category
Negative Markup	22.1%	31.6%	53.7%	20.0%	32.9%	53.0%
Zero Markup	3.7%	19.8%	23.5%	9.4%	25.2%	34.7%
$0 to $5	3.7%	4.5%	8.2%	2.3%	3.0%	5.4%
$5 to $10	0.6%	1.5%	2.0%	0.5%	1.0%	1.5%
$10 to $15	0.2%	1.1%	1.3%	0.3%	0.5%	0.8%
$15 to $20	0.3%	0.4%	0.8%	0.1%	0.4%	0.5%
$20 to $25	0.2%	0.3%	0.5%	0.2%	0.2%	0.4%
$25 to $50	3.0%	2.8%	5.8%	1.2%	1.4%	2.6%
$50 to $75	1.4%	1.3%	2.7%	0.2%	0.3%	0.4%
$75 to $100	0.2%	0.5%	0.8%	0.0%	0.2%	0.2%
Above $100	0.2%	0.5%	0.7%	0.1%	0.4%	0.5%
Total Positive Markup	9.8%	13.0%	22.8%	4.9%	7.4%	12.3%
Total	35.6%	64.4%	100.0%	34.4%	65.6%	100.0%

Market Power Mitigation and Markup

Fully effective local market power mitigation would not allow a seller that fails the structural market power test (the TPS test) to set prices with a positive markup. With the flaws in PJM's implementation of the TPS test, resources can and do set prices with a positive markup while failing the TPS test.

Table 3-148 categorizes day-ahead and real-time marginal unit intervals by markup level and TPS test status. In the first three months of 2026, 2.4 percent of real-time marginal unit intervals and 2.6 percent of day-ahead marginal unit hours included a positive markup even though the resource failed the TPS test for local market power. Unmitigated local market power affects PJM market prices. Zero markup with a TPS test failure indicates the mitigation of a marginal unit.

Table 3-148 Percent of marginal unit intervals with markup and local market power: January through March, 2026

	Day-ahead Market			Real-time Market		
Markup Category	Not Failing TPS Test	Failing TPS Test	Percent in Category	Not Failing TPS Test	Failing TPS Test	Percent in Category
Negative Markup	47.1%	6.6%	53.7%	43.8%	9.2%	53.0%
Zero Markup	19.1%	4.4%	23.5%	25.9%	8.8%	34.7%
$0 to $5	6.8%	1.4%	8.2%	4.3%	1.1%	5.4%
$5 to $10	1.7%	0.4%	2.0%	1.1%	0.4%	1.5%
$10 to $15	1.1%	0.2%	1.3%	0.6%	0.2%	0.8%
$15 to $20	0.7%	0.0%	0.8%	0.4%	0.1%	0.5%
$20 to $25	0.4%	0.1%	0.5%	0.3%	0.1%	0.4%
$25 to $50	5.6%	0.2%	5.8%	2.3%	0.3%	2.6%
$50 to $75	2.6%	0.1%	2.7%	0.3%	0.1%	0.4%
$75 to $100	0.7%	0.1%	0.8%	0.2%	0.0%	0.2%
Above $100	0.6%	0.1%	0.7%	0.3%	0.2%	0.5%
Total Positive Markup	20.2%	2.6%	22.8%	9.9%	2.4%	12.3%
Total	86.4%	13.6%	100.0%	79.6%	20.4%	100.0%

The markup of marginal units was zero or negative in 87.7 percent of real-time marginal unit intervals and 77.2 percent of day-ahead marginal unit intervals in the first three months of 2026. Zero and negative markup are the expected results in a competitive market. Allowing positive markups to affect prices in the presence of market power permits the exercise of market power and has a negative impact on the competitiveness of the PJM energy market. This problem can and should be addressed.

4 Energy Uplift (Operating Reserves)

In a well designed wholesale power market, energy uplift is paid as credits to market participants under specified conditions in order to ensure that competitive energy and ancillary service market outcomes do not require efficient resources operating at the direction of PJM, to operate at a loss.[1] Referred to in PJM as operating reserve credits, lost opportunity cost credits, dispatch differential lost opportunity credits, reactive services credits, synchronous condensing credits or black start services credits, these uplift payments are intended to be one of the incentives to generation owners to offer their energy to the PJM energy market for dispatch based on short run marginal costs and to operate their units as directed by PJM. These uplift credits are paid by PJM market participants as operating reserve charges, reactive services charges, synchronous condensing charges or black start services charges. Fast start pricing, implemented on September 1, 2021, required a new uplift credit to pay the lost opportunity costs of units that are backed down in real time to accommodate the less flexible fast start units for which fast start pricing assumes flexibility. The result of fast start pricing is to create a greater reliance on uplift rather than price signals as an incentive to follow PJM's instructions.

Uplift is an inherent part of the PJM market design. Part of uplift is the result of the nonconvexity of power production costs. Uplift payments cannot be eliminated, but uplift payments should be limited to the efficient level. In wholesale power market design, a choice must be made between efficient prices and prices that fully compensate costs. Economists recognize that no single price achieves both goals in markets with nonconvex production costs, like the costs of producing electric power.[2] [3] In wholesale power markets like PJM, efficient prices equal the short run marginal cost of production by location. The dispatch of generators based on these efficient price signals minimizes the total market cost of production. For generators with nonconvex costs, marginal cost prices may not cover the total cost of starting the generator and running at the efficient output level. Uplift payments cover the difference. The PJM market design concept incorporates efficient prices with minimal uplift payments.

But PJM's practice does not minimize uplift payments. In some cases, PJM pays uplift that is not consistent with the rules. In some cases, the rules permit the payment of uplift that is not consistent with the goal of PJM market design. Regulation revenues should be included as an offset to the daily uplift calculation for generators that receive regulation revenues, but are not currently included. The need for uplift should be calculated on a daily basis, as incorporated in the initial PJM market design, rather than on an hourly segment basis. The goal of uplift should be to ensure that units are not required to run at a loss on a daily basis. The goal should not be to lock in profits in some hourly segments and require uplift in other hourly segments. In the case where PJM makes multiday commitments, the uplift calculation should cover the entire multiday period rather than allowing a generator to be paid uplift on day one and earn significant profits on day three. There are identified improvements to PJM's application of the rules, and to the market design and uplift rules that could reduce uplift payments to the efficient level.

PJM's day-ahead generator credits and balancing generator credits are calculated by operating day and by hourly segments. Segments for day-ahead generator credits equal the hours in which the unit cleared in the day-ahead market. Segments for balancing generator credits are defined as the greater of the length of the day-ahead schedule and the unit's minimum run time. Intervals in excess of the minimum run time or in excess of the hours cleared in the day-ahead market become new segments. The net revenues in those new segments are not counted as contributing to covering costs in the initial segment. The reverse is also true. Uplift is paid even when total net revenues cover or more than cover costs when the entire day is included.

In PJM, all energy payments to demand response resources are uplift payments. The energy payments to these demand response resources are not part of the supply and demand balance, they are not paid by LMP revenues

1 Losses occur when gross energy and ancillary services market revenues are less than short run marginal costs, including all elements of the energy offer, which are startup, no load and incremental offers, and the unit is following PJM instructions including both commitment and dispatch instructions. There is no corresponding assurance required when units are self scheduled or not following PJM dispatch instructions.

2 *See* Stoft, *Power System Economics: Designing Markets for Electricity,* New York: Wiley (2002) at 272; Mas-Colell, Whinston, and Green, *Microeconomic Theory*, New York: Oxford University Press (1995) at 570; and Quinzii, *Increasing Returns and Efficiency*, New York: Oxford University Press (1992)

3 The production of output is convex if the production function has constant or decreasing returns to scale, which result in constant or rising average costs with increases in output. Production is nonconvex with increasing returns to scale, which is the case when generating units have start or no load costs that are large relative to marginal costs. *See* Mas-Colell, Whinston, and Green at 132.

and therefore the energy payments to demand response resources have to be paid as uplift. The energy payments to economic DR are funded by real-time load and real-time exports. The energy payments to emergency DR are funded by participants with net energy purchases in the real-time energy market. The current payment structure for DR is an inefficient element of the PJM market design.[4]

Polar Vortex 2025 and Winter Storm Fern (2026) both resulted in a significant increase in uplift payments as a result of the fact that PJM chose a significantly different and better approach to the preparations for these winter weather events than PJM had taken for Winter Storm Elliott. Rather than rely on ineffective, inefficient, risky, and disruptive PAI incentives to provide assurance that generators would be ready for cold weather, PJM took direct steps to ensure a reliable outcome. The market results of PJM's actions during Polar Vortex 2025 and Winter Storm Fern vindicated PJM's strategy. PJM took conservative measures to ensure reliability by scheduling resources in advance of the day-ahead energy market. PJM took conservative measures to ensure transmission reliability, including voltage support. These commitments were not made to meet reserve requirements. Higher reserve requirements would not have addressed the Polar Vortex 2025 issues, Winter Storm Fern issues, or cold weather reliability issues more generally. Units needed to buy gas in advance and actually be operating in order to meet the reliability issues.

The uplift associated with Polar Vortex 2025 and Winter Storm Fern was an expected outcome of conservative operations. This uplift is part of the way that PJM markets work and was the result of PJM's successful conservative operations approach to dealing with cold weather risks. PJM's commitment approach during Polar Vortex 2025 and Winter Storm Fern was significantly different than in 2024, for example. PJM committed only 1.4 percent of units on schedules less flexible than PLS during Polar Vortex 2025 compared to 17.2 percent during weather alert days in 2024.

The market results of PJM's actions in preparation for and during Winter Storm Gerri, Polar Vortex 2025 and Winter Storm Fern were better than the market results of PJM's actions during Winter Storm Elliott. Uplift was the expected result and a preferred result to the penalties that resulted from Winter Storm Elliott. Nonetheless, improvements are needed to make the advance commitment process more predictable and transparent and formalized, and made as market based as possible, in order to limit uplift to an efficient and effective level. These improvements should include implementing a multiday security constrained economic dispatch and commitment model that incorporates PJM's load forecast, energy cost forecasts, and units at risk, and provides commitment recommendations to PJM's dispatch prior to the Day-Ahead Energy Market. In addition, there should be rules about energy offers used for these commitments, and uplift rules should be revised to account for the multiday nature of these commitments.

4 Demand response payments are addressed in Section 6: Demand Response.

Overview

Energy Uplift Credits

- **Energy uplift credits.** Total energy uplift credits increased by $509.5 million, or 108.4 percent, during the first three months of 2026 compared to the first three months of 2025, from $470.2 million to $979.7 million.
- **Types of energy uplift credits.** During the first three months of 2026, total energy uplift credits included $210.7 million in day-ahead generator credits, $649.6 million in balancing generator credits, $118.9 million in lost opportunity cost credits. Dispatch differential lost opportunity credits were $0.3 million during the first three months of 2026.
- **Types of units.** During the first three months of 2026, non-coal steam units received 96.4 percent of the day-ahead generator credits and steam coal units received 0.5 percent of day-ahead generator credits. Combustion turbines received 1.5 percent of balancing generator credits and 12.9 percent of lost opportunity cost credits. Combined cycle plants and combustion turbines received 62.6 percent of dispatch differential lost opportunity credits, and hydro units received 3.3 percent of dispatch differential lost opportunity credits
- **Concentration of energy uplift credits.** In the first three months of 2026, the top 10 units receiving energy uplift credits received 38.2

percent of all credits and the top 10 organizations received 78.9 percent of all credits.

- **Lost opportunity cost credits.** Lost opportunity cost credits increased by $109.3 million, from $9.6 million to $118.9 million, or 1,135.0 percent, during the first three months of 2026 compared to the first three months of 2025.

  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 75.4 percent of the $118.9 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.** During the first three months of 2026, total energy uplift charges increased by $509.0 million, or 108.1 percent, compared to the first three months of 2025, from $470.7 million to $979.8 million.
- **Types of Energy Uplift Charges.** During the first three months of 2026, total uplift charges included $210.7 million in day-ahead operating reserve charges, $768.4 million in balancing generator charges, $0.1 million in reactive charges, and $0.2 million in black start services, and $0.4 million in local congestion charges.

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 for energy produced because of not following dispatch. (Priority: Medium. First reported 2018. Status: Not adopted.)[5]
- The MMU recommends that PJM pay uplift based on the offer at the lower of the actual unit output or the desired MW. (Priority: Medium. First reported 2018. Status: Not adopted.)[6]
- 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:

5 PJM filed proposed changes to the uplift rules with the FERC on October 7, 2025 ("Reform to Energy Uplift Credit Rules," Docket No. ER26-59-000). The Commission Order on December 5, 2025, accepted the PJM Proposal as filed. PJM expects to implement the changes in 202

6 Id.

- — 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.)
- 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.)
- 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.)[7]

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

7 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).

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 for 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 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 fast start pricing.[8] 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.[9] 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

8 Fast start pricing was approved by FERC and implemented on September 1, 2021. See 173 FERC ¶ 61,244 (2020).
9 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).

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.

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.

The MMU has recommended that PJM 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 has paid uplift to units even when they do not operate as requested by PJM, i.e. when units do not follow dispatch.

PJM and the MMU have defined and worked to implement systematic and verifiable rules for determining when units are following dispatch as a primary screen for eligibility for uplift payments. On October 7, 2025, PJM submitted those rules as tariff revisions. The rules address the fact that, under the status quo, resources receive make whole payments for energy produced while not following PJM's dispatch instructions. The rules were approved by FERC on December 5, 2025. PJM expects to implement the rules in the first half of 2027.

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.

Energy Uplift Credits

The level of energy uplift credits paid to specific units depends on the level of the resource's energy offer, the LMP, the resource's operating parameters and the decisions of PJM operators. Energy uplift credits result in part from decisions by PJM operators, who follow reliability requirements and market rules, to start resources or to keep resources operating even when LMP is less than the offer price including incremental, no load and startup costs. Energy uplift payments also result from units' operational parameters that require PJM to schedule or commit resources when they are not economic. Energy uplift payments currently also result, incorrectly, from decisions by units to maintain an output level not consistent with PJM dispatch instructions. The resulting costs not covered by energy revenues are collected as energy uplift credits.

The day-ahead operating reserves category includes multiple credit types that are paid to resources cleared uneconomically in the day-ahead market. These resources include generators, imports, and load response.

The balancing operating reserves category includes multiple credit types based on the service provided by the resources. These credit types, paid to compensate for uneconomic generation in the balancing market, include generator credits, lost opportunity cost credits, dispatch differential lost opportunity cost credits, local constraint control credits, load response credits, import credits, and canceled resource credits. The largest credit type in the balancing operating reserves category is balancing generator credits. The reactive services category includes multiple credit types. Black start services credits exist to compensate resources for black start services in the day-ahead and balancing markets, as well as testing. Black start credits and local constraint credits are not broken out individually and are included in the category of balancing generator credits, matching PJM's Market Settlements Reporting System.

Table 4-1 shows the uplift totals for each credit category during the first three months of 2025 and 2026.[10] During the first three months of 2026, energy uplift credits increased by $509.5 million or 108.4 percent compared to the first three months of 2025. PJM commitment and dispatch decisions associated with the Winter Storm Fern caused significant increases in day-ahead generator credits, balancing generator credits, and lost opportunity cost credits.

The dispatch differential lost opportunity cost is a credit that exists only as a result of fast start pricing. This credit is paid to flexible resources that are artificially dispatched down, to an output level below the level that is economic at fast start prices, in order to accommodate inflexible fast start resources. Fast start pricing was introduced on September 1, 2021.

10 Billing data can be modified by PJM Settlements at any time to reflect changes in the evaluation of energy uplift. The billing data reflected in this report were current on April 9, 2026.

Table 4-1 Energy uplift credits by category: January through March, 2025 and 2026[11]

Category	Type	(Jan - Mar) 2025 Credits (Millions)	(Jan - Mar) 2026 Credits (Millions)	Change	Percent Change	2025 Share	2026 Share
Day-Ahead	Generators	$162.5	$210.7	$48.2	29.7%	34.6%	21.5%
Balancing	Generators	$296.4	$649.6	$353.2	119.1%	63.0%	66.3%
	Canceled Resources	$0.0	$0.0	($0.0)	(100.0%)	0.0%	0.0%
	Lost Opportunity Cost	$9.6	$118.9	$109.3	1,135.0%	2.0%	12.1%
	Dispatch Differential Lost Opportunity Cost	$1.1	$0.3	($0.8)	(73.5%)	0.2%	0.0%
Synchronous Condensing	Synchronous Condensing	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Synchronous Condensing Lost Opportunity Cost	$0.0	$0.0	$0.0	NA	0.0%	0.0%
Reactive Services	Generators	$0.5	$0.1	($0.4)	(76.9%)	0.1%	0.0%
	Lost Opportunity Cost	$0.0	$0.0	($0.0)	(100.0%)	0.0%	0.0%
	Condensing	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Condensing Lost Opportunity Cost	$0.0	$0.0	$0.0	NA	0.0%	0.0%
Total		$470.2	$979.7	$509.5	108.4%	100.0%	100.0%

Categories of Credits and Charges

Energy uplift charges include day-ahead and balancing operating reserves, reactive services, synchronous condensing and black start services categories. Uplift credits paid to individual participants are paid for by charges to the groups of PJM market participants. The groups of participants charged varies depending on the type of uplift credit. For this reason, operating reserve charges do not always have the same value as operating reserve credits, since not all categories of uplift credits are paid for by the same PJM participants. For example, in the case of local constraint credits, credits are paid to generators in the form of balancing operating reserve credits but charges are allocated as local constraint charges. The same applies in the case of units scheduled day ahead for reactive support, for which the credits are paid in the form of day-ahead operating reserve credits but charges are allocated as reactive services charges. Table 4-2 and Table 4-3 show the categories of credits and charges and their relationships.

For example, in Table 4-2, day-ahead operating reserve credits for generators are paid for by day-ahead operating reserve charges. Those charges are paid for by market participants in proportion to their day-ahead load, day-ahead exports, and virtual transactions (DECs and UTCs). The charges are aggregated over the entire RTO region. Balancing generator reserve credits are paid for by two different types of charges: balancing operating reserve charges for reliability and balancing operating reserve charges for deviations. Charges for reliability are paid for by PJM members in proportion to their real-time load and real-time export transactions. Reliability charges are aggregated regionally over the entire RTO region, within the Western region, or within the Eastern region. Balancing operating reserve charges for deviations are paid for by PJM members in proportion to their deviations, which includes virtuals (INCs and DECs), UTCs, load, and interchange. The deviation charges are aggregated regionally over the entire RTO region, within the Western region, and within the Eastern region. Lost opportunity cost credits are paid for by balancing operating reserve charges for deviations. The charges for deviations are paid for by PJM members in proportion to their deviations, which includes virtuals (INCs and DECs), UTCs, load, and interchange. The deviation charges are aggregated regionally over the entire RTO region.

Starting with the *2024 Annual State of the Market Report for PJM*, black start credits and local constraint credits are not broken out individually and are included in the category of balancing generator credits. Similarly, cancellation charges, lost opportunity charges, and dispatch differential lost opportunity cost charges are not broken out individually and are included in the category of balancing generator charges.

11 Year to year change is rounded to $0.01 million.

Table 4-3 shows the relationship between credits and charges for resources providing reactive, synchronous condensing, and black start services. For example, the five sub-categories of reactive services credits (day-ahead operating reserves, generator, LOC, condensing, and synchronous condensing LOC) are paid by two different charge categories: reactive service charges and local constraint reactive services. The reactive service charges are paid by PJM members in proportion to their zonal real-time load, while the local constraint reactive service charges are paid for by transmission owners.

Table 4-2 Day-ahead and balancing operating reserve credits and charges

	Credit Category	Charges Category	Charge Responsibility	Geographic Charge Aggregation
DAY-AHEAD	Day-Ahead Operating Reserve Transaction	Day-Ahead Operating Reserves for Transactions	Day-Ahead Load, Day-Ahead Exports, DECs & UTCs	RTO Region
	Day-Ahead Operating Reserve Generator	Day-Ahead Operating Reserve for Generators		
	Day-Ahead Operating Reserves for Load Response	Day-Ahead Operating Reserve for Load Response		
	Unallocated Negative Load Congestion Charges Unallocated Positive Generation Congestion Credits	Unallocated Congestion		
BALANCING	Balancing Generator Reserves	Balancing Operating Reserve for Reliability	Real-Time Load plus Real-Time Export Transactions	RTO, Eastern, and Western Region
		Balancing Operating Reserve for Deviations	Deviations (includes virtual bids, UTCs, load, and interchange)	
	Dispatch Differential Lost Opportunity Cost (DDLOC)	Balancing Operating Reserve for Deviations	Real-Time Load plus Real-Time Export Transactions	RTO Region
	Canceled Resources	Balancing Operating Reserve for Deviations	Deviations (includes virtual bids, UTCs, load, and interchange)	
	Lost Opportunity Cost (LOC)			
	Real-Time Import Transactions			
	Balancing Operating Reserves for Load Response	Balancing Operating Reserve for Load Response	Deviations (includes virtual bids, UTCs, load, and interchange)	
	Local Constraints Control	NA	Transmission Owner	NA

Table 4-3 Reactive services, synchronous condensing and black start services credits and charges

	Credits Category	Charges Category	Charge Responsibility
Reactive	Day-Ahead Operating Reserve Generator Reactive Services LOC Reactive Services Condensing Reactive Services	Reactive Services Charge	Zonal Real-Time Load
	Synchronous Condensing LOC Reactive Services	Local Constraint Reactive Services	Transmission owner
Synchronous Condensing	Synchronous Condensing Synchronous Condensing LOC	Synchronous Condensing	Real-Time Load Real-Time Export Transactions
Black Start	Day-Ahead Operating Reserve Balancing Operating Reserve Black Start Testing Black Start LOC	Black Start Service Charge	Zone/Non-zone Peak Transmission Use and Point to Point Transmission Reservations

Types of Units

Table 4-4 shows the distribution of total energy uplift credits by unit type during the first three months of 2026 and the first three months of 2025. A combination of factors led to overall increased uplift payments, including unit specific issues and market issues including high fuel costs and PJM conservative operations during Winter Storm Fern (January 22 through 30, 2026).

Uplift credits paid to combustion turbines increased by $325.6 million or 240.0 percent during the first three months of 2026 compared to the first three months of 2025. During the first three months of 2026, CTs received 73.7 percent of lost opportunity cost credits. Lost opportunity cost credits increased by $109.3 million or 1,135.0 percent during the first three months of 2026 compared to the first three months of 2025.

Uplift credits paid to steam coal units increased by $16.8 million or 97.3 percent during the first three months of 2026 compared to the first three months of 2025. During the first three months of 2026, day-ahead uplift credits in the PEPCO Zone made up 96.8 percent of total day-ahead uplift credits, and accounted for 137.8 percent of the increase in day-ahead uplift during the first three months of 2026, primarily as a result of unit specific issues for the Chalk Point 3 and 4 units. Historically, steam coal units Brandon Shores 1 and 2, received a large share of day-ahead uplift credits, but during the first three months of 2026 Brandon Shores 1 and 2 did not receive any day-ahead credits, a consequence of their new RMR status which was implemented June 1, 2025.

Uplift credits paid to non-coal (gas or oil fired) steam units increased by $74.4 million or 46.9 percent during the first three months of 2026 compared to the first three months of 2025. During the first three months of 2026, gas or oil fired steam units received $267.2 million, 27.3 percent of total credits, compared to $266.3 million, 27.9 percent of total credits during the first three months of 2025. During the first three months of 2026, the day-ahead uplift paid to gas or oil fired steam units was 12.8 percent higher than during the first three months of 2025, and accounted for 118.5 percent of the total increase in day-ahead operating reserves. The increase in day-ahead generator credits paid to gas or oil fired steam units in the PEPCO Zone accounted for 137.8 percent of the overall increase in day-ahead generator credits during the first three months of 2026. In the PEPCO Zone, gas fired steam units Chalk Point 3 and 4 received $202.3 million in uplift during the first three months of 2026.[12] During Winter Storm Fern, non-coal steam units received $102.7 million, or 51.8 percent of all credits received by non-coal steam units during the first three months of 2026. Non-coal steam units received 15.7 percent of total uplift credits during the Winter Storm Fern.

Uplift credits paid to combined cycle plants increased by $82.4 million or 50.2 percent during the first three months of 2026 compared to the first three months of 2025. This increase occurred primarily in January 2026 as a result of the commitments made in advance of the day-ahead energy market during the Winter Storm Fern. Winter Storm Fern accounted for 91.7 percent of the uplift credits paid to combined cycle plants, and accounted for 29.5 percent of total uplift credits during the first three months of 2026. During this period, uplift credits to wind units were $1.4 million, down by 78.4 percent compared to the first three months of 2025.

Table 4-4 Total energy uplift credits by unit type: January through March, 2025 and 2026[13] [14]

Unit Type	(Jan - Mar) 2025 Credits (Millions)	(Jan - Mar) 2026 Credits (Millions)	Change	Percent Change	(Jan - Mar) 2025 Share	(Jan - Mar) 2026 Share
Combined Cycle	$151.7	$246.5	$94.8	62.5%	32.3%	25.2%
Combustion Turbine	$135.7	$461.3	$325.6	240.0%	28.9%	47.1%
Diesel	$1.4	$2.9	$1.6	112.4%	0.3%	0.3%
Hydro	$0.7	$0.0	($0.6)	(98.5%)	0.1%	0.0%
Nuclear	$0.0	$0.0	$0.0	NA	0.0%	0.0%
Solar	$0.1	$0.3	$0.2	273.1%	0.0%	0.0%
Steam - Coal	$17.2	$34.0	$16.8	97.3%	3.7%	3.5%
Steam - Other	$158.7	$233.1	$74.4	46.9%	33.8%	23.8%
Wind	$4.7	$1.4	($3.3)	(69.6%)	1.0%	0.1%
Total	$470.2	$979.7	$509.5	108.4%	100.0%	100.0%

12 See Table 4-14.
13 Table 4-4 does not include balancing imports credits and load response credits in the total amounts
14 Solar units should be ineligible for all uplift payments because they do not follow PJM's dispatch instructions. The MMU notified PJM of the discrepancy.

Table 4-5 shows the distribution of energy uplift credits by category and by unit type during the first three months of 2026. The largest share of day-ahead credits, 96.9 percent, went to steam units (non-coal and coal). Steam units tend to be longer lead time units that are committed before the operating day. If a steam unit is needed for reliability and it is uneconomic, it will be committed in the day-ahead energy market and receive day-ahead uplift credits. The PJM market rules permit combustion turbines (CT), unlike other unit types, to be committed and decommitted in the real-time market. As a result of the rules and the characteristics of CT offers, CTs received 57.0 percent of balancing credits and 73.7 percent of lost opportunity cost credits. Combustion turbines committed in the real-time market may be paid balancing credits due to inflexible operating parameters, volatile real-time LMPs, and intraday segment settlements. Combustion turbines committed in the day-ahead market but not committed in real time receive lost opportunity credits to cover the profits they would have made had they operated in real time.

Table 4-5 Energy uplift credits by unit type: January through March, 2026

Unit Type	Day-Ahead Generator	Balancing Generator	Canceled Resources	Lost Opportunity Cost	Reactive Services	Synchronous Condensing	Dispatch Differential Lost Opportunity Cost
Combined Cycle	1.5%	35.9%	0.0%	8.5%	0.0%	0.0%	16.5%
Combustion Turbine	1.5%	57.0%	0.0%	73.7%	100.0%	0.0%	46.1%
Diesel	0.0%	0.0%	0.0%	2.2%	0.0%	0.0%	0.1%
Hydro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.3%
Nuclear	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Solar	0.0%	0.0%	0.0%	0.2%	0.0%	0.0%	5.0%
Steam - Coal	0.5%	2.7%	0.0%	12.9%	0.0%	0.0%	5.1%
Steam - Other	96.4%	4.4%	0.0%	1.4%	0.0%	0.0%	2.3%
Wind	0.0%	0.0%	0.0%	1.2%	0.0%	0.0%	21.4%
Total (Millions)	$210.7	$649.6	$0.0	$118.9	$0.1	$0.0	$0.3

Day-Ahead Unit Commitment for Reliability

PJM can schedule units as must run in the day-ahead energy market that would otherwise not have been committed in the day-ahead market, when needed in real time to address reliability issues. Such reliability issues include thermal constraints, reactive transfer interface constraints, and reactive service.[15] Units committed for reliability by PJM are eligible for day-ahead operating reserve credits and may set LMP if raised above economic minimum and follow the dispatch signal. Participants can submit units as self scheduled (must run), meaning that the unit must be committed, but a unit submitted as self scheduled by a participant is not eligible for day-ahead operating reserve credits.[16]

Pool scheduled units are units that are committed in the day-ahead market based on economics. Units committed for reliability by PJM are units that are committed to satisfy reliability needs, regardless of whether the offers are economic. Self scheduled units are self committed by the generation owner and are not eligible for uplift. Pool scheduled units and units committed for reliability are made whole in the day-ahead energy market if their total cost-based offer (including no load and startup costs) is greater than the revenues from the day-ahead energy market. Such units are paid day-ahead uplift.

It is illogical and unnecessary to pay units day-ahead operating reserves because units do not incur any costs to run in the day-ahead market and any revenue shortfalls are addressed by balancing operating reserve payments.

Balancing Uplift (Operating Reserve) Credits/ Balancing Generator Credits

Balancing operating reserve (BOR) credits are paid to resources that operate as requested by PJM that do not recover all of their operating costs from market revenues. Balancing operating reserves include multiple credit types that are paid to units in the balancing market, such as generator credits, lost opportunity cost credits, dispatch differential lost opportunity cost credits, local constraints control credits, load response credits, import credits, and canceled resource credits. Balancing generator credits are the largest category of balancing operating reserves. Balancing generator credits are calculated by hourly segments as the difference between a resource's revenues (day-ahead market, balancing market, reserve markets,

15 See OA Schedule 1 § 3.2.3(b).
16 See OA Schedule 1 § 3.2.3(a).

reactive service credits, and day-ahead operating reserve credits but excluding regulation revenues) and its real-time offer (startup, no load, and incremental energy offer). Segments for balancing generator credits are defined as the greater of the day-ahead schedule and the unit's minimum run time. Intervals in excess of the minimum run time are treated as new segments. Table 4-5 shows that combustion turbines (CTs) received 57.0 percent of balancing generator credits in during the first three months of 2026, or $370.2 million. Combined cycle plants (CCs) received 35.9 percent of balancing generator credits during the first three months of 2026, or $233.3 million. During Winter Storm Fern, the balancing generator credits to CTs exceeded CCs.

Uplift is higher than necessary because settlement rules do not include all revenues and costs for the entire day. Uplift is also higher than necessary because settlement rules do not disqualify units from receiving uplift when they do not follow PJM's dispatch instructions. Units should be disqualified from receiving uplift when the units do not follow dispatch instructions, block load or self schedule.

Table 4-1 shows that balancing generator credits increased by 330.2 percent during the first three months of 2026 compared to the first three months of 2025.

CTs that operate on a day-ahead schedule tend to receive lower balancing generator credits because it is more likely that the day-ahead LMPs will support (prices above offer) committing the units. The day-ahead model optimizes the system for all 24 hours, unlike in real time when PJM uses ITSCED to optimize CT commitments with an approximately two hour look ahead. In addition, uplift rules continue to define all day-ahead scheduled hours as one segment for the uplift calculation (in which profits and losses during all hours offset each other). The shorter segments in real-time are defined by the minimum run time and allow for fewer offsets, resulting in greater amounts of uplift. Losses during the minimum run time segment are not offset by profits made in other segments on that day.

There are multiple reasons why the commitment of CTs is different in the day-ahead and real-time markets, including differences in the hourly pattern of load, and differences in interchange transactions. Modeling differences between the day-ahead and real-time markets also affect CT commitment, including: the modeling of different transmission constraints in the day-ahead and real-time market models; the exclusion of soak time for generators in the day-ahead market model; and the different optimization time periods used in the day-ahead and real-time markets.

Lost Opportunity Cost Credits

Balancing operating reserve lost opportunity cost (LOC) credits are intended to provide an incentive for units to follow PJM's dispatch instructions when PJM's dispatch instructions deviate from a unit's desired or scheduled output. LOC credits are paid under two scenarios.[17] The first scenario occurs if a unit of any type generating in real time with an offer price lower than the real-time LMP at the unit's bus is manually reduced or suspended by PJM due to a transmission constraint or other reliability issue. In this scenario the unit will receive a credit for LOC based on its desired output. Such units are not actually forgoing an option to increase output because the reliability of the system and in some cases the generator depend on reducing output. This LOC is referred to as real-time LOC. The second scenario occurs if a combustion turbine or diesel engine clears the day-ahead energy market, but is not committed in real time. In this scenario the unit will receive a credit which covers any lost profit in the day-ahead financial position of the unit plus the balancing energy market position. This LOC is referred to as day-ahead LOC.

Table 4-6 shows monthly day-ahead and real-time LOC credits during 2025 and the first three months of 2026. During the first three months of 2026, LOC credits increased by $109.3 million or 1,135.0 percent compared to the first three months of 2025. The overall increase included an $86.3 million increase in day-ahead LOC and a $22.9 million increase in real-time LOC.

Table 4-4 shows that during the first three months of 2026, wind units received $1.4 million of uplift, down by $3.3 million compared to the first three months of 2025. Wind units that are capacity resources are now required to procure Capacity Interconnection Rights (CIRs) equal to the maximum facility output included in the calculation of their ELCC value. Wind units that are capacity

17 Desired output is defined as the MW on the generator's offer curve consistent with the LMP at the generator's bus.

resources are paid uplift when PJM requests that the units reduce output below the maximum facility output but above the CIR level. Units do not have a right to inject power at levels greater than the CIR level that they pay for and therefore should not be paid uplift when system conditions do not permit output at a level greater than the CIR. The real-time lost opportunity costs credits paid to wind units should use the lowest of the desired output, the estimated output based on actual wind conditions, and the capacity interconnection rights (CIRs) as the definition of the foregone opportunity.

Table 4-6 Monthly lost opportunity cost credits[18] [19] (Millions): January 2025 through March 2026

	2025			2026		
	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total
Jan	$2.6	$4.4	$7.0	$74.2	$17.1	$91.3
Feb	$0.1	$0.4	$0.5	$9.4	$8.9	$18.3
Mar	$0.7	$1.5	$2.1	$6.1	$3.3	$9.4
Apr	$1.1	$1.0	$2.1			
May	$2.0	$0.1	$2.2			
Jun	$5.5	$1.4	$7.0			
Jul	$2.4	$0.6	$3.1			
Aug	$1.7	$0.4	$2.1			
Sep	$2.8	$0.2	$2.9			
Oct	$2.7	$0.2	$2.9			
Nov	$1.2	$0.7	$1.9			
Dec	$4.4	$5.2	$9.6			
Total (Jan - Mar)	$3.34	$6.33	$9.7	$89.7	$29.3	$118.9
Share (Jan - Mar)	34.6%	65.4%	100.0%	75.4%	24.6%	100.0%
Total	$27.2	$16.1	$43.4	$89.7	$29.3	$118.9
Share	62.8%	37.2%	100.0%	75.4%	24.6%	100.0%

18 Table 4-6 does not include pumped hydro lost opportunity cost credits in Real-Time Lost Opportunity Cost Credits.
19 Table 4-6 includes CT lost opportunity cost forfeiture in the Day-Ahead Lost Opportunity Cost. *See* "MSRS Report Format Documentation: CT Lost Opportunity Cost Forfeiture, version 5" for more details <https://www.pjm.com/markets-and-operations/billing-settlements-and-credit/msrs-reports-documentation.aspx>.

Energy Uplift Charges

Energy Uplift Charges

Table 4-7- shows that energy uplift charges for the first three months of 2026 were $979.8 million, or 2.7 percent of total PJM billing.

Table 4-7 Total energy uplift charges: 2001 through March, 2026

	Total Energy Uplift Charges (Millions)	Change (Millions)	Percent Change	Energy Uplift as a Percent of Total PJM Billing
2001	$284.0	$67.0	30.9%	8.5%
2002	$273.7	($10.3)	(3.6%)	5.8%
2003	$376.5	$102.8	37.6%	5.4%
2004	$537.6	$161.1	42.8%	6.1%
2005	$712.6	$175.0	32.6%	3.1%
2006	$365.6	($347.0)	(48.7%)	1.7%
2007	$503.3	$137.7	37.7%	1.6%
2008	$474.3	($29.0)	(5.8%)	1.4%
2009	$322.7	($151.6)	(32.0%)	1.2%
2010	$623.2	$300.5	93.1%	1.8%
2011	$603.4	($19.8)	(3.2%)	1.7%
2012	$649.8	$46.4	7.7%	2.2%
2013	$843.0	$193.2	29.7%	2.5%
2014	$961.2	$118.2	14.0%	1.9%
2015	$312.0	($649.2)	(67.5%)	0.7%
2016	$136.7	($175.3)	(56.2%)	0.4%
2017	$127.3	($9.4)	(6.9%)	0.3%
2018	$198.2	$70.9	55.7%	0.4%
2019	$88.5	($109.7)	(55.3%)	0.2%
2020	$90.9	$2.4	2.7%	0.3%
2021	$178.4	$87.5	96.3%	0.3%
2022	$284.5	$106.1	59.5%	0.3%
2023	$158.7	($125.8)	(44.2%)	0.3%
2024	$270.0	$111.3	70.1%	0.5%
2025	$764.8	$606.1	381.9%	0.9%
2026 (Jan - Mar)	$979.8	$215.0	28.1%	2.7%

Table 4-8 shows total energy uplift charges by category for the first three months of 2025 and 2026. The increase of $509.0 million is comprised of a $48.2 million increase in day-ahead uplift (operating reserve) charges, a $461.5 million increase in balancing generator charges, a $0.4 million decrease in reactive service charges, a $0.5 million decrease in synchronous condensing charges, and a $0.3 million increase in local congestion charges. Starting with the *2024 Annual State of the Market Report for PJM*, cancellation charges, lost opportunity charges, and dispatch differential lost opportunity cost charges are not broken out individually and are included in the category of balancing generator charges, matching PJM's Market Settlements Reporting System.

Table 4-8 Total energy uplift charges by category: January through March, 2025 and 2026[20]

Category	(Jan - Mar) 2025 Charges (Millions)	(Jan - Mar) 2026 Charges (Millions)	Change (Millions)	Percent Change
Day-Ahead Operating Reserves	$162.5	$210.7	$48.2	29.7%
Balancing Operating Reserves	$306.8	$768.4	$461.5	150.4%
Reactive Services	$0.5	$0.1	($0.4)	(77.1%)
Synchronous Condensing	$0.5	$0.0	($0.5)	(100.0%)
Black Start Services	$0.3	$0.2	($0.0)	(14.9%)
Local Congestion Charges	$0.1	$0.4	$0.3	381.7%
Total	$470.7	$979.8	$509.0	108.1%
Energy Uplift as a Percent of Total PJM Billing	2.5%	2.7%	0.9%	36.7%

Table 4-9 compares monthly energy uplift charges by category for 2025 through the first three months of 2026.

Table 4-9 Monthly energy uplift charges: January 2025 through March 2026

	2025 Charges (Millions)						2026 Charges (Millions)					
	Day-Ahead	Balancing	Reactive Services	Local Congestion	Black Start Services	Total	Day-Ahead	Balancing	Reactive Services	Local Congestion	Black Start Services	Total
Jan	$153.9	$245.8	$0.0	$0.1	$0.0	$399.8	$177.3	$680.6	$0.0	$0.0	$0.0	$857.9
Feb	$2.5	$32.5	$0.0	$0.0	$0.1	$35.2	$31.1	$55.55	$0.1	$0.3	$0.2	$87.3
Mar	$6.1	$28.6	$0.5	$0.0	$0.1	$35.3	$2.3	$32.16	$0.0	$0.0	$0.0	$34.5
Apr	$3.9	$36.6	$0.0	$0.0	$0.1	$40.6						
May	$2.9	$16.6	$0.0	$0.0	$0.0	$19.6						
Jun	$5.8	$31.5	$0.0	$0.0	$0.0	$37.3						
Jul	$2.3	$45.8	$0.0	$0.0	$0.0	$48.1						
Aug	$3.1	$24.0	$0.0	$0.0	$0.0	$27.1						
Sep	$0.9	$16.1	$0.0	$0.0	$0.0	$17.1						
Oct	$0.6	$19.7	$0.0	$0.1	$0.0	$20.5						
Nov	$0.7	$32.2	$0.0	$0.0	$0.0	$32.9						
Dec	$18.2	$33.1	$0.0	$0.0	$0.0	$51.3						
Total (Jan - Mar)	$162.5	$306.8	$0.5	$0.1	$0.3	$470.2	$210.7	$768.4	$0.1	$0.4	$0.2	$979.8
Share (Jan - Mar)	34.6%	65.3%	0.1%	0.0%	0.1%	100.0%	21.5%	78.4%	0.0%	0.0%	0.0%	100.0%
Total	$200.9	$562.5	$0.7	$0.3	$0.4	$764.8	$210.7	$768.4	$0.1	$0.4	$0.2	$979.8
Share	26.3%	73.6%	0.1%	0.0%	0.1%	100.0%	21.5%	78.4%	0.0%	0.0%	0.0%	100.0%

20 The total PJM billing used in Table 4-8 is different from the total cost shown in Table 1-9. The total PJM billing in Table 4-8 represents the total dollars that pass through the PJM settlement process, while the total cost shown in Table 1-9 is the total cost to load and includes additional costs to load accounted for outside the PJM settlement process.

Table 4-10 shows the composition of the balancing operating reserve charges. Balancing operating reserve charges consist of balancing operating reserve reliability charges (credits to generators), balancing operating reserve deviation charges (credits to generators and import transactions), balancing operating reserve charges for economic load response and balancing local constraint charges. Balancing operating reserve charges increased by $461.5 million or 150.4 percent during the first three months of 2026 compared to the first three months of 2025.

Table 4-10 Balancing operating reserve charges: January through March, 2025 and 2026

Category	(Jan - Mar) 2025 Charges (Millions)	(Jan - Mar) 2026 Charges (Millions)	Change	Percent Change	2025 Share	2026 Share
Balancing Operating Reserve Reliability Charges	$258.1	$601.1	$342.9	132.8%	84.1%	78.2%
Balancing Operating Reserve Deviation Charges	$48.7	$167.3	$118.6	243.6%	15.9%	21.8%
Balancing Operating Reserve Charges for Load Response			$0.0	NA	0.0%	0.0%
Balancing Local constraint Charges	$0.1	$0.4	$0.3	381.7%	0.0%	0.0%
Total	$306.8	$768.4	$461.5	150.4%	100.0%	100.0%

Uplift Eligibility

In PJM, units have either a pool scheduled or self scheduled commitment status. Pool scheduled units are committed by PJM while self scheduled units are committed by generation owners. Table 4-11 provides a description of commitment and dispatch status, uplift eligibility and the ability to set price.[21] In the day-ahead energy market only pool scheduled resources are eligible for day-ahead operating reserve credits. A unit may be self scheduled in the day-ahead market and then be pool scheduled and dispatched in subsequent days to remain online, in which case they would be eligible for uplift for the subsequent days. In the real-time energy market only pool scheduled resources that follow PJM's dispatch are defined in the tariff as eligible for balancing operating reserve credits. However, in practice, units receive uplift credits when not following PJM's dispatch signal. Units are paid day-ahead operating reserve credits based on their scheduled operation for the entire day. Balancing operating reserve credits are paid on a segmented basis for each period defined by the greater of the day-ahead schedule and minimum run time. Resources receive day-ahead and balancing operating reserve credits only when they are eligible and unable to recover their operating cost for the day or segment. [22]

Table 4-11 Dispatch status, commitment status and uplift eligibility[23]

		Commitment Status	
Dispatch Status	Dispatch Description	Self Scheduled (units committed by the generation owner)	Pool Scheduled and following PJM's dispatch signal (units committed by PJM)
Block Loaded	MWh offered to PJM as a single MWh block which is not dispatchable	Not eligible to receive uplift Not eligible to set LMP	Eligible to receive uplift Not eligible to set LMP unless fast start eligible
Economic Minimum	MWh from the nondispatchable economic minimum component for units that offer a dispatchable range to PJM	Not eligible to receive uplift Not eligible to set LMP	Eligible to receive uplift Not eligible to set LMP unless fast start eligible
Dispatchable	MWh above the economic minimum level for units that offer a dispatchable range to PJM.	Only eligible to receive LOC credits if dispatched down by PJM Eligible to set LMP	Eligible to receive uplift Eligible to set LMP

Energy Uplift Issues

Uplift Resettlement

Some units have been 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. The MMU has requested that PJM correctly resettle the uplift payments in these cases.[24] Since 2018, the cumulative resettlement requests total $17.9 million, of which PJM has agreed and resettled only $3.9 million over the last two years, 22.0 percent, and 0.9 percent are waiting for a PJM response. The remaining 77.1 percent occurred prior to April 2024 and is subject to

21 PJM has modified the basic rules of eligibility to set price using its CT price setting logic.

22 Resources do not recover their operating cost when market revenues for the day are less than the short run marginal cost defined by the startup, no load, and incremental offer curve.

23 PJM allows block loaded CTs to set LMP by relaxing the economic minimum by 10 to 20 percent using CT price setting logic.

24 To date, the MMU has only requested resettlement of the most egregious cases.

the OATT's limitation on claims. That limit does not apply and would not have applied if PJM informed the market participant within two years of the occurrence of the issue.[25] PJM should inform market participants of a potential issue when the MMU raises the issue with PJM and the market participant in order to ensure that the issues can be addressed. PJM has refused to accept the voluntary return of incorrectly paid uplift credits by generators when the MMU has identified such cases.

The MMU identifies units that are not following dispatch and that are therefore not eligible to receive uplift payments. These findings are communicated to unit owners and to PJM. The units are identified by comparing their actual generation to the dispatch level that they should have achieved based on the real-time LMP, unit operating parameters (e.g. economic minimum, maximum and ramp rate) and energy offer.

Uplift Forfeiture Rule

The uplift forfeiture rule was introduced in 2000 after PJM observed that in the summer of 1999 units could circumvent the $1,000/MWh offer cap by submitting high offers associated with a long minimum run time (e.g. 24 hours). The rule states that units will not be paid operating reserve credits (uplift) when they are scheduled on their price-based offers during maximum generation conditions and their effective energy offer price exceeds $1,000 per MWh.[26] Maximum generation conditions include maximum generation emergencies, maximum generation emergency alerts, and when PJM schedules units based on the anticipation of a maximum generation emergency or maximum generation emergency alert.

PJM declared maximum generation conditions for January 27, 2026, during Winter Storm Fern, and uplift forfeiture was triggered for some units in the day-ahead market. The uplift forfeiture rule was triggered because these units received uplift with an effective energy price-based offer that exceeded $1,000 per MWh. Uplift forfeiture was not triggered for the balancing market. In 2025, PJM declared maximum generation conditions for January 22, June 23-25, July 15-16, July 24-25, and July 28-30. The uplift forfeiture rule was triggered on June 23-24, July 15-16, and July 24 because units received uplift with an effective price-based offer that exceeded $1,000 per MWh. As a result of the uplift forfeiture rule, 2025 BOR uplift payments that would have been paid on June 23-24, July 15-16, and July 24 were not paid.

25 OATT § 10.4.
26 See OA Schedule 1 Section 3.2.3 (m) Operating Reserves

Regulation Market Offsets

PJM does not include regulation market payments as an offset like other market revenues in the operating reserve calculations, although it should be included. Including regulation market revenues would result in lower uplift. Table 4-12 shows that the regulation market revenues in the first three months of 2026 were $188.1 million and that the balancing generator credits for those units receiving regulation revenues were $42.0 million. The table shows that if the regulation market revenues had been incorporated in the operating reserve calculation as an offset, the balancing generator payment for those units would have been $39.4 million instead of $42.0 million, $2.6 million lower, or 6.2 percent.

Table 4-12 Adjusted operating reserve credits: January through March, 2026

Month	Regulation Market Revenues (Millions)	Balancing Generator Credits (Millions)	Adjusted Balancing Generator Credits (Millions)	Difference
Jan	$61.8	$38.9	$37.5	($1.4)
Feb	$79.0	$2.6	$1.5	($1.1)
Mar	$47.2	$0.4	$0.3	($0.1)
Total	$188.1	$42.0	$39.4	($2.6)

Concentration of Energy Uplift Credits

The recipients of uplift payments are highly concentrated by unit and by company. This concentration results from a combination of unit operating parameters, PJM's persistent need to commit specific units out of merit in particular locations and the fact that a lack of full transparency has made it more difficult for competition to affect these payments.[27] Table 4-13 shows the concentration of energy uplift credits. The top 10 units received 22.5 percent of total energy uplift credits in the first three months of 2026. The top

27 As a result of FERC Order No. 844, PJM began publishing total uplift credits by unit by month for credits paid on and after July 1, 2019, on September 10, 2019.

10 companies received 78.9 percent of total energy uplift credits during the first three months of 2026.

Table 4-13 Top 10 units and organizations energy uplift credits: January through March, 2026

Category	Type	Top 10 Units Credits (Millions)	Top 10 Units Credits Share	Top 10 Organizations Credits (Millions)	Top 10 Organizations Credits Share
Day-Ahead	Generators	$206.9	98.2%	$1.8	0.9%
Balancing	Canceled Resources	$0.0	NA	$0.0	NA
	Generators	$200.4	30.8%	$509.2	78.4%
	Lost Opportunity Cost	$35.2	29.6%	$90.4	76.0%
	Dispatch Differential Lost Opportunity Cost	$0.1	24.3%	$0.2	66.3%
	Total Balancing	$235.6	30.6%	$599.8	78.0%
Reactive Services		$0.1	100.0%	$0.1	100.0%
Total		$374.6	38.2%	$772.8	78.9%

Unit Specific Uplift Payments

FERC Order No. 844 allows PJM and the MMU to publish unit specific uplift payments by category by month. Table 4-14 through Table 4-18 show the top 10 recipients of total uplift, day-ahead operating reserve credits and lost opportunity cost credits.

Chalk Point 3 and 4 are non-coal steam units in the PEPCO Zone with an ICAP of 582 MW each. In the first three months of 2026, the Chalk Point 3 and 4 units received a combined $204.5 million in uplift, 20.9 percent of total uplift payments. During the first three months of 2025, the Chalk Point 3 and 4 units received a combined $139.3 million in uplift, 29.6 percent of total uplift payments.

Brandon Shores 1 and Brandon Shores 2 and Wagner 3 and Wagner 4 submitted retirement notifications to PJM and the MMU in April and October of 2023. Brandon Shores 1 and 2 are coal units in BGE with an ICAP of 635 MW and 638 MW. Wagner 3 and 4 are oil units in BGE with an ICAP of 305 MW and 397 MW. PJM determined that these resources were needed for reliability until transmission upgrades can be completed. In the first three months of 2026, the Brandon Shores 1 and 2 units received a combined $13.9 million in uplift, 1.4 percent of total uplift payments. During the first three months of 2025, the Brandon Shores 1 and 2 units received a combined $15.9 million in uplift, 3.4 percent of total uplift payments. In the first three months of 2026, the Wagner 3 and 4 units received a combined $7.4 million in uplift, 0.8 percent of total uplift payments. During the first three months of 2025, the Wagner 3 and 4 units received a combined $4.0 million in uplift, 0.8 percent of total uplift payments.

Table 4-14 Top 10 recipients of total uplift: January through March, 2026

Rank	Unit Name	Zone	Total Uplift Credit	Share of Total Uplift Credits
1	PEP CHALKPOINT 4 F	PEPCO	$116,442,021	11.9%
2	PEP CHALKPOINT 3 F	PEPCO	$88,037,201	9.0%
3	JC REDOAK 1 CC	JCPL	$33,075,677	3.4%
4	ACE WEST DEPTFORD CROWN POINT 1 CC	AECO	$25,737,235	2.6%
5	PE PHILLIPS ISL LINWOOD 1 CC	PECO	$22,881,838	2.3%
6	COM 940 CORDOVA 3 CC	COMED	$21,134,685	2.2%
7	COM 900 ELWOOD 5 CT	COMED	$19,938,093	2.0%
8	COM 900 ELWOOD 7 CT	COMED	$16,723,538	1.7%
9	DPL ROCK SPRINGS CT4	DPL	$15,448,248	1.6%
10	DPL ROCK SPRINGS 1 CT	DPL	$15,216,367	1.6%
Total of Top 10			$374,634,904	38.2%
Total Uplift Credits			$979,710,367	100.0%

Table 4-15 Top 10 recipients of day-ahead generation credits: January through March, 2026

Rank	Unit Name	Zone	Day-Ahead Operating Reserve Credit	Share of Day-Ahead Operating Reserve Credits
1	PEP CHALKPOINT 4 F	PEPCO	$116,093,217	55.1%
2	PEP CHALKPOINT 3 F	PEPCO	$86,164,475	40.9%
3	PEP ST CHARLES-KELSON RIDGE 2 CC	PEPCO	$937,563	0.4%
4	PEP ST CHARLES-KELSON RIDGE 1 CC	PEPCO	$848,994	0.4%
5	PL MONTOUR 1 F	PPL	$575,272	0.3%
6	DPL VIENNA 8 F	DPL	$565,438	0.3%
7	ME BIRDSBORO 1 CC	METED	$432,756	0.2%
8	COM 951 AURORA 3 CT	COMED	$432,204	0.2%
9	COM 951 AURORA 1 CT	COMED	$419,968	0.2%
10	COM 951 AURORA 2 CT	COMED	$390,046	0.2%
Total of Top 10			$206,859,933	98.2%
Total day-ahead operating reserve credits			$210,726,746	100.0%

Table 4-16 Top 10 recipients of balancing generator credits: January through March, 2026

Rank	Unit Name	Zone	Balancing Generator Credits	Share of Balancing Generator Credits
1	JC REDOAK 1 CC	JCPL	$33,075,603	15.7%
2	ACE WEST DEPTFORD CROWN POINT 1 CC	AECO	$25,729,656	12.2%
3	PE PHILLIPS ISL LINWOOD 1 CC	PECO	$22,842,619	10.8%
4	COM 940 CORDOVA 3 CC	COMED	$21,134,685	10.0%
5	COM 900 ELWOOD 5 CT	COMED	$19,937,902	9.5%
6	COM 900 ELWOOD 7 CT	COMED	$16,723,374	7.9%
7	DPL ROCK SPRINGS CT4	DPL	$15,448,248	7.3%
8	DPL ROCK SPRINGS 1 CT	DPL	$15,216,367	7.2%
9	DPL ROCK SPRINGS CT3	DPL	$15,210,384	7.2%
10	DPL ROCK SPRINGS 2 CT	DPL	$15,037,879	7.1%
Total of Top 10			$200,356,720	95.1%
Total balancing operating reserve credits			$649,632,322	100.0%

Table 4-17 Top 10 recipients of lost opportunity cost credits: January through March, 2026

Rank	Unit Name	Zone	Lost Opportunity Cost Credits	Share of Lost Opportunity Cost Credits
1	PEP DICKERSON H 1 CT	PEPCO	$5,011,083	4.2%
2	VP FOUR RIVERS 1 CT	DOM	$4,399,887	3.7%
3	PEP DICKERSON H 2 CT	PEPCO	$3,720,208	3.1%
4	AEP AMOS 3 F	AEP	$3,614,687	3.0%
5	VP LOUISA 5 CT	DOM	$3,573,193	3.0%
6	VP MARSHRUN 1 CT	DOM	$3,341,829	2.8%
7	VP DOSWELL 2 CT	DOM	$3,235,281	2.7%
8	VP MARSHRUN 3 CT	DOM	$3,066,160	2.6%
9	AEP GAVIN 2 F	AEP	$2,605,253	2.2%
10	AEP GAVIN 1 F	AEP	$2,602,991	2.2%
Total of Top 10			$35,170,573	29.6%
Total lost opportunity cost credits			$118,946,902	100.0%

Table 4-18 Top 10 recipients of dispatch differential lost opportunity cost credits: January through March, 2026

Rank	Unit Name	Zone	Dispatch Differential Lost Opportunity Cost Credits	Share of Dispatch Differential Lost Opportunity Cost Credits
1	VP DOSWELL 2 CT	DOM	$10,137	3.6%
2	AEP FOX SQUIRREL 1 SP	AEP	$9,314	3.3%
3	FE LEMOYNE 1 CT	ATSI	$7,137	2.5%
4	PE CONOWINGO 1-11 H	PECO	$7,052	2.5%
5	VP LOUISA 5 CT	DOM	$6,774	2.4%
6	AP SOUTHBEND 2 CT	APS	$6,578	2.3%
7	COM PILOT HILL 1 WF	COMED	$6,393	2.2%
8	COM 942 NELSON 1 CC	COMED	$5,659	2.0%
9	COM 942 NELSON 2 CC	COMED	$5,545	1.9%
10	AP SOUTHBEND 1 CT	APS	$4,694	1.6%
Total of Top 10			$69,283	24.3%
Total dispatch differential lost opportunity cost credits			$284,546	0.2%

Reliability Must Run Units

Brandon Shores 1 and Brandon Shores 2 and Wagner 3 and Wagner 4 began providing Reliability Must Run (RMR) Service on June 1, 2025.[28] When PJM requests the units to operate, they are paid LMP and receive uplift as balancing generator credits.

Table 4-19 shows Non-RMR and RMR uplift credits for Brandon Shores 1 and Brandon Shores 2 and Wagner 3 and Wagner 4 in 2025 and during the first three months of 2026. In the first five months of 2025, Brandon Shores 1 and Brandon Shores 2 and Wagner 3 and Wagner 4 were capacity resources in the PJM market and received a total of $19.9 million in day-ahead generator credits and $3.7 million in balancing generator credits. In the last seven months of 2025, Brandon Shores 1 and Brandon Shores 2 and Wagner 3 and Wagner 4 began providing RMR service and received $41.4 million in balancing generator credits. During the first three months of 2026, Brandon Shores 1 and Brandon Shores 2 and Wagner 3 and Wagner 4 received $21.2 million in balancing generator credits and $0.1 million in lost opportunity cost credits.

28 *See* 191 FERC ¶ 61,098 (2025), *reh'g denied*, 191 FERC ¶ 62,189 (2025).

Table 4-19 Uplift credits for Brandon Shores and Wagner by RMR status

	RMR Status	Unit	Day-Ahead Generator Credits	Balancing Generator Credits (Millions)	Lost Opportunity Cost Credits (Millions)	Dispatch Differential Lost Opportunity Cost Credits (Millions)	Total Credits (Millions)
2025	Non-RMR (Jan - May)	BC WAGNER 3 F	$3.3	$0.2	$0.0	$0.0	$3.5
		BC WAGNER 4 F	$1.5	$0.5	$0.0	$0.0	$1.9
		BC BRANDON SHORES 1 F	$6.5	$1.2	$0.0	$0.0	$7.7
		BC BRANDON SHORES 2 F	$8.6	$1.9	$0.0	$0.0	$10.5
		Total	$19.9	$3.7	$0.0	$0.0	$23.6
	RMR (Jun - Dec)	BC WAGNER 3 F	$0.0	$9.4	$0.0	$0.0	$9.4
		BC WAGNER 4 F	$0.0	$1.7	$0.0	$0.0	$1.7
		BC BRANDON SHORES 1 F	$0.0	$20.8	$0.0	$0.0	$20.8
		BC BRANDON SHORES 2 F	$0.0	$9.5	$0.0	$0.0	$9.5
		Total	$0.0	$41.4	$0.0	$0.0	$41.4
2026	RMR (Jan - Mar)	BC WAGNER 3 F	$0.0	$4.5	$0.0	$0.0	$4.5
		BC WAGNER 4 F	$0.0	$2.9	$0.0	$0.0	$2.9
		BC BRANDON SHORES 1 F	$0.0	$7.0	$0.0	$0.0	$7.0
		BC BRANDON SHORES 2 F	$0.0	$6.8	$0.0	$0.0	$6.9
		Total	$0.0	$21.2	$0.1	$0.0	$21.3

Uplift Credits and Market Power Mitigation

Absent effectively implemented market power mitigation, unit owners that submit noncompetitive offers or offers with inflexible operating parameters, can exercise market power, resulting in noncompetitive and excessive uplift payments.

The three pivotal supplier (TPS) test is the test for local structural market power in the energy market.[29] If the TPS test is failed, market power mitigation is applied by offer capping the resources of the owners identified as having local market power to their cost-based offer. Offer capping is designed to set offers at competitive levels.

Table 4-20 shows day-ahead operating reserve credits paid to committed and dispatched units called on the first three months of 2026, classified by commitment schedule type. Units using parameter limited schedules received $0.9 million or 0.4 percent of day-ahead operating reserve credits in the first three months of 2026, units using price-based offers received $2.8 million or 1.3 percent, and units using cost-based offers received $207.0 or 98.2 percent.

Table 4-20 Day-ahead operating reserve credits by Offer Type: January through March, 2026

Offer Type	Day Ahead Operating Reserve Credits (Millions)	Share of DAOR
Cost	$207.0	98.2%
Price	$2.8	1.3%
PLS	$0.9	0.4%
Total	$210.7	100.0%

Table 4-21 shows day-ahead operating reserve credits paid to units called on days with hot and cold weather alerts, classified by commitment schedule type. On weather alert days, PJM can require the use of parameter limited schedules (PLS) to prevent the exercise of market power through the use of inflexible parameters. Of all the day-ahead credits received during days with weather alerts, 98.3 percent went to units that were committed on cost schedules, which are parameter limited, 0.6 percent went to units that were committed on price PLS schedules, 1.0 percent went to units committed on price schedules less flexible than PLS, and 0.1 percent on price schedules as flexible as PLS. These results indicate a significant change in PJM's commitment approach during weather alerts. PJM committed only 1.0 percent of units on schedules less flexible than PLS during weather alert days in the first three months of 2026 compared to 1.4 percent during weather alert days during the first three months of 2025.

Table 4-21 Day-ahead operating reserve credits during weather alerts by commitment schedule: January through March, 2026

Commitment Type During Hot and Cold Weather Alerts	Day Ahead Operating Reserve Credits	Share of DAOR during emergency alerts
Committed on cost (cost capped)	$152,955,751	98.3%
Committed on price schedule as flexible as PLS	$183,872	0.1%
Committed on price schedule less flexible than PLS	$1,581,942	1.0%
Committed on price PLS	$877,978	0.6%
Total	$155,599,544	100.0%

29 See the MMU Technical Reference for PJM Markets, at "Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

Gas fired generators may request temporary exceptions to parameter limits such as minimum run time based on restrictions imposed by natural gas pipelines, including ratable takes.[30] Table 4-22 shows the day-ahead operating reserve uplift credits received from 2018 through the first three months of 2026 by units that submitted parameter exception requests for a 24 hour minimum run time based on gas pipeline restrictions. In the first three months of 2026, 97 units requested an exception for a 24 hour minimum run time and 82 units received uplift payments amounting to $204.7 million of day ahead operating reserves and $263.7 million in balancing operating reserves, or 97.2 percent of total day-ahead operating reserves and 40.6 percent of total balancing operating reserves, corresponding to 20.9 percent and 26.9 percent of total uplift.

Table 4-22 Uplift credits for units with 24 hour minimum run times due to gas pipeline restrictions: 2018 through March 2026

Year	Day-Ahead Operating Reserve Credits (Millions)	Balancing Generator Credits (Millions)	Number of Units with 24 Hour Min Run Time Exceptions	Number of Units with 24 Hour Min Run Time Exceptions that Received Uplift
2018	$4.9	$0.7	25	2
2019	$0.2	$0.6	37	12
2020	$0.2	$0.2	13	2
2021	$0.7	$0.6	61	42
2022	$14.4	$9.8	81	38
2023	$10.7	$1.5	75	23
2024	$30.2	$2.4	79	41
2025	$149.4	$31.7	93	64
2026 (Jan - Mar)	$204.7	$263.7	97	82

Winter Storm Fern (January 22 through 30, 2026)

Winter Storm Fern is defined to include the meteorological definition of the storm plus related cold weather from January 22 through 30, 2026. Winter Storm Fern resulted in significant uplift payments. Table 4-23 summarizes the uplift payments by category during Winter Storm Fern. During the storm, generating units received $107.9 million in day-ahead operating reserve credits, 14.1 percent of total Winter Storm Fern uplift and 51.2 percent of total day-ahead operating reserves during the first three months of 2026. During the storm, generating units received $574.4 million in balancing generator credits, 75.0 percent of total Winter Storm Fern uplift, and 88.4 percent of total balancing generator credits during the first three months of 2026. Total uplift payments during the storm were $766.3 million, 78.2 percent of total uplift during the first three months of 2026.

Table 4-23 Energy uplift credits by category during Winter Storm Fern

Category	Type	2026 Winter Storm Fern Credits (Millions)	(Jan - Mar) 2026 Credits (Millions)	Share of Winter Storm Fern Uplift (Jan. 22 - 30)	Winter Storm Fern Share of 2026 Uplift (Jan - Mar)
Day-Ahead	Generators	$107.9	$210.7	14.1%	51.2%
Balancing	Generators	$574.4	$649.6	75.0%	88.4%
	Canceled Resources	$0.0	$0.0	0.0%	NA
	Lost Opportunity Cost	$83.9	$118.9	10.9%	70.5%
	Dispatch Differential Lost Opportunity Cost	$0.1	$0.3	0.0%	36.5%
Synchronous Condensing	Synchronous Condensing	$0.0	$0.0	0.0%	NA
	Synchronous Condensing Lost Opportunity Cost	$0.0	$0.0	0.0%	NA
Reactive Services	Generators	$0.0	$0.0	0.0%	NA
	Lost Opportunity Cost	$0.0	$0.1	0.0%	0.0%
	Condensing	$0.0	$0.0	0.0%	NA
	Condensing Lost Opportunity Cost	$0.0	$0.0	0.0%	NA
Total		$766.3	$979.7	100.0%	78.2%

Uplift during Winter Storm Fern was a result of advance commitments made by PJM in anticipation of the cold weather. PJM made advance commitments for the January 24 – February 2 operating days. These commitments were made before day-ahead energy market offers were due. Some of the units cleared the day-ahead energy market 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 energy market received balancing operating reserves credits because their offers were not fully 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, natural gas supply illiquidity, and efforts to conserve oil fired generation in order to meet the forecasted peaks.[31] PJM also committed specific units in advance of

30 See OA Schedule 1 Section 6.6 (C) Minimum Generator Operating Parameters – Parameter Limited Schedules.

31 See "Winter Storm Gerri Review January 13–22, 2024," PJM presentation to the Operating Committee. (February 8, 2024) <https://www.pjm.com/-/media/committees-groups/committees/oc/2024/20240208/20240208-item-11---cold-weather-update.ashx>.

the day-ahead market to ensure transmission system reliability, including voltage support.

As a result of the low temperatures expected on Saturday, January 24 and subsequent days, PJM committed units before temperatures reached the expected levels. On Friday, January 23, natural gas traded as a multiday package, referred to as the weekend package. The weekend package included gas days January 24, 25, and 26, covering the period from 10:00 AM on Saturday, January 24, to 10:00 AM on Tuesday, January 27. PJM committed units on Friday to ensure that the units could procure gas over the weekend. For the same reasons, PJM also committed gas units in advance of the January 27 to January 30 gas days, and in advance of the January 31 through February 2 weekend package.

Table 4-24 shows the total energy uplift credits by unit type during Winter Storm Fern, as a share of total uplift in the first three months of 2026, and as a share of total Fern uplift. Combined cycle plants received $226.1 million in uplift payments, non-coal steam units received $120.7 million and combustion turbines received $400.5 million. Winter Storm Fern accounted for 91.7 percent of the uplift received by combined cycle plants during the first three months of 2026, and during the storm combined cycle plants received 29.5 percent of the uplift.

Table 4-24 Total energy uplift credits by unit type during the 2026 Winter Storm Fern

Unit Type	2026 Winter Storm Fern Credits (Millions)	(Jan - Mar) 2026 Credits (Millions)	Share of Winter Storm Fern Uplift (Jan. 22 - 30)	Winter Storm Fern Share of 2026 Uplift (Jan - Mar)
Combined Cycle	$226.1	$246.5	29.5%	91.7%
Combustion Turbine	$400.5	$461.3	52.3%	86.8%
Diesel	$1.7	$2.9	0.2%	59.0%
Hydro	$0.0	$0.0	0.0%	23.1%
Nuclear	$0.0	$0.0	0.0%	0.3%
Solar	$0.0	$0.3	0.0%	1.4%
Steam - Coal	$16.5	$34.0	2.2%	48.4%
Steam - Other	$120.7	$233.1	15.7%	51.8%
Wind	$0.8	$1.4	0.1%	56.8%
Total	$766.3	$979.7	100.0%	78.2%

Uplift is not a simple matter of paying uplift to all units or to all gas-fired units or to all oil-fired units. Not all units scheduled in advance of the day-ahead market were paid uplift. Uplift was concentrated in ComEd, where 51 units had a combined ICAP of 6,567.5 MW and received $247.3 million in uplift, or 30.7 percent of Winter Storm Fern uplift. The top ten units in total uplift excluding ComEd had a combined ICAP of 5,188.3 MW and received $272.5 million, or 33.8 percent of Winter Storm Fern uplift.

5 Capacity Market

In PJM, the capacity market exists to make the energy market work. Energy powers lights and computers and air conditioners. Capacity does not power anything. The capacity market needs to define the total MWh of energy that are needed to reliably serve load. The capacity market needs to provide the missing money. A primary reason to have a capacity market is that the energy market does not provide adequate net revenues to provide incentives for entry and for maintaining existing units. The obligation of load serving entities (LSEs) to own capacity equal to the peak demand plus a reserve margin was a longstanding feature of the PJM Operating Agreement before the creation of the PJM markets. The initial impetus to a capacity market in PJM, a request by the Pennsylvania PUC, was to support retail competition by ensuring that small new entrant competitive LSEs would have access to capacity at a competitive price without having to build capacity or purchase capacity bilaterally from incumbent generation owners at monopoly prices. The PJM Capacity Market was created by FERC in order to prevent the exercise of market power that resulted from a bilateral market in which the ownership of capacity was concentrated. That logic continues to apply today. The first, the daily capacity market, created in 1999, was replaced in 2007 by the current design based on the recognition that the energy market resulted in a shortfall in net revenues compared to that necessary to attract and retain adequate resources for the reliable operation of the energy market. The exogenous reliability requirement to have a level of capacity in excess of the level that would result from the operation of an energy market alone reduces the level and volatility of energy market prices and reduces the duration of high energy market prices. This reduces net revenue to generation owners which reduces the incentive to invest. In order for the PJM markets to be self sustaining, the net 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 and ancillary services markets.

The only goal of the detailed design of the capacity market is to ensure that the opportunity for that revenue equilibration exists through a competitive process. PJM's most recent filing to modify the definition of the capacity market demand curve (VRR curve) explicitly fails to recognize that equilibration logic and undercuts that revenue equilibration mechanism by failing to include a full net revenue offset in the definition of the maximum price on the demand curve.

The Capacity Performance (CP) design was a radical change to the capacity market paradigm. The CP design is a failed experiment. The fundamental mistake of the CP design was to attempt to recreate energy market incentives in the capacity market. The CP model was an explicit attempt to bring energy market shortage pricing into the capacity market design. The CP model was designed on the unfounded assumption that shortage prices in the energy market were not high enough and needed to be increased via the capacity market.

PJM's introduction of its significantly modified ELCC method in the 2025/2026 BRA was another radical change to the capacity market design. While it is a good idea to evaluate unit specific performance and a good idea to recognize that risk occurs in the winter as well as the summer and that risks may be correlated, ELCC was implemented before it could be fully tested and unintended consequences evaluated. The results of the 2025/2026 BRA and subsequent BRAs illustrate the extreme sensitivity of the market outcomes to a range of assumptions and decisions about market design details that were not adequately tested or reviewed with stakeholders.[1]

The challenge is to create a straightforward capacity market design that meets the simple objectives of a capacity market and that does not become a vehicle for energy market incentives or rent seeking or attempts to limit the ways in which specific types of generation participate in PJM markets. Energy market incentives should remain in the energy market.

1 The MMU prepared a series of reports on the 2025/2026, 2026/2027 and 2027/2028 BRA results which can be found on the Monitoring Analytics website here: <https://www.monitoringanalytics.com/reports/Reports/2024.shtml>, <https://www.monitoringanalytics.com/reports/Reports/2025.shtml>; and <https://www.monitoringanalytics.com/reports/Reports/2026.shtml>

The PJM market design is based on the must offer and must buy obligations of capacity resources. All capacity resources are required to offer into the capacity auctions. The categorical exemption for intermittent resources, capacity storage resources, and hybrid resources from the RPM must offer requirement was eliminated for all resources except demand resources in February 2025.[2] All LSEs must buy capacity equal to their peak load plus a reserve margin through the market.

Each organization serving PJM load must meet its capacity obligations through the PJM Capacity Market, where load serving entities (LSEs) must pay the locational capacity price for their zone. LSEs can also construct generation and offer it into the capacity market, enter into bilateral contracts, develop demand resources and offer them into the capacity market, or construct transmission upgrades and offer them into the capacity market

There are significant market design issues in the PJM Capacity Market that currently prevent the market from achieving competitive results.

One of the most important issues currently facing the PJM Capacity Market is the addition of large amounts of data center load, both actual and forecast. The MMU concludes that the failure to recognize and address the role of large data center loads is a direct cause of higher prices and will continue to result in even higher prices unless the related issues are addressed. PJM should not simply permit the interconnection of large data center loads if it cannot do so reliably, with adequate generation capacity to meet those loads.

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.[3] The conclusions for 2025 and the first three months of 2026 are a result of the MMU's evaluation of the 2025/2026, 2026/2027, and 2027/2028 Base Residual Auctions.[4] [5] [6] [7] [8] [9] [10] [11] [12] [13] [14]

Table 5-1 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**

- 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.[15] 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.[16]

2 FERC approved extending the RPM must offer requirement to intermittent resources, capacity storage resources, and hybrid resources but not to demand resources on February 20, 2025. 190 FERC ¶ 61,117.

3 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.

4 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>

5 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>.

6 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>.

7 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>

8 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>.

9 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>.

10 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part G Revised," (June 3, 2025) <https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_G_20250603_Revised.pdf>.

11 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part H," (July 31, 2025) <https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_H_20250731.pdf>.

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

13 See "Analysis of the 2026/2027 RPM Base Residual Auction - Part B," (March 3, 2026) <https://www.monitoringanalytics.com/reports/Reports/2026/IMM_Analysis_of_the_20262027_RPM_Base_Residual_Auction_Part_B_20260303.pdf>.

14 See "Analysis of the 2027/2028 RPM Base Residual Auction – Part A," (January 5, 2026) <https://www.monitoringanalytics.com/reports/Reports/2026/IMM_Analysis_of_the_20272028_RPM_Base_Residual_Auction_Part_A_20260105.pdf>.

15 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.

16 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.

- Participant behavior was evaluated as not competitive in the 2026/2027 BRA. Effective with the 2026/2027 Delivery Year, the market seller offer cap definition was modified to include unit specific standalone Capacity Performance Quantifiable Risk (CPQR) and segmented unit specific offer caps.[17] The offers in the 2026/2027 BRA included those based on standalone CPQR offer caps. 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.
- Market performance was evaluated as not competitive based on the 2026/2027 Base Residual Auction as a result of 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 recognize and address the role of large data center loads is a direct cause of higher prices and will continue to result in even higher prices unless the related issues are addressed.
- Market design was evaluated as mixed because while there are many positive features of the capacity market design and some of the MMU's recommendations were implemented in the 2026/2027 BRA, there are several features of the RPM design which still threaten competitive outcomes. These include the lack of a queue for the addition of large new data center loads, details of PJM's ELCC implementation, the definition of market seller offer caps, the failure to apply the RPM must offer requirement to demand resources, the inclusion of performance assessment interval (PAI) penalties, 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.[18]

17 190 FERC ¶ 61,117 (2025).

18 While PJM filed for and FERC accepted the inclusion of RMR resources Brandon Shores and Wagner plants in the 2026/2027 BRA and 027/2028 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).

Overview

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.[19] 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.[20]

Under RPM, capacity obligations are annual.[21] 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.[22] 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.[23] 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.[24] 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.[25] If the installed reserve margin resulting from the total UCAP committed through self supply or BRAs for three consecutive years is more than one percentage point 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

19 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in this report and include all capacity within the PJM footprint

20 See 186 FERC ¶ 61,080 (2024), *reh'g order*, 189 FERC ¶ 61,043 (2024).

21 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.

22 See 126 FERC ¶ 61,275 at P 86 (2009).

23 See Letter Order, FERC Docket No. ER10-366-000 (January 22, 2010).

24 See 126 FERC ¶ 61,275 at P 88 (2009). There have been no Conditional Incremental Auctions.

25 See OATT Attachment DD § 16.

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 2026/2027 RPM Third Incremental Auction was conducted in the first three months of 2026.

Market Structure

- **RPM Installed Capacity.** In the first three months of 2026, RPM installed capacity decreased 30.0 MW or 0.0 percent, from 184,220.8 MW on January 1, to 184,190.8 MW on March 31. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- **Reserves.** Total reserves on June 1, 2025, were 19,999.9 MW, which is 205.1 MW (UCAP) short of the required reserve level of 20,205.0 MW (UCAP). On June 1, 2025, the target installed reserve margin was 17.8 percent, and the actual reserve margin was only 17.6 percent.
- **RPM Installed Capacity by Fuel Type.** Of the total installed capacity on March 31, 2026, 48.2 percent was gas; 20.3 percent was coal; 17.5 percent was nuclear; 4.4 percent was hydroelectric; 2.2 percent was oil; 2.4 percent was wind; 0.3 percent was solid waste; and 4.6 percent was solar.
- **Market Concentration.** In the 2026/2027 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.[26] 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.[27] [28] [29]
- **Imports and Exports.** Of the 1,144.8 MW of imports offered in the 2027/2028 RPM Base Residual Auction, 1,005.9 MW cleared. Of the cleared imports, 695.6 MW (69.2 percent) were from MISO.
- **Demand Resources.** Committed DR was 5,782.9 MW for June 1, 2025, as a result of cleared capacity for demand resources in RPM auctions for the 2025/2026 Delivery Year (6,265.9 MW) less replacement capacity (483.0 MW).
- **Energy Efficiency Resources.** EE is not a capacity resource but is paid the capacity market clearing price as a subsidy through the 2025/2026 Delivery Year. Committed EE was 1,481.6 MW for June 1, 2025, as a result of MW offered at a price less than or equal to the RPM auction clearing price in RPM auctions for the 2025/2026 Delivery Year (1,493.2 MW) less replacement MW (11.6 MW).

Market Conduct

- **2026/2027 RPM Third Incremental Auction.** Of the 985 generation resources that submitted Capacity Performance offers, unit specific offer caps were calculated for four generation resources (0.4 percent).

Market Performance

- The 2026/2027 RPM Third Incremental Auction was conducted in the first three months of 2026. 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. The weighted average capacity price for the 2026/2027 Delivery Year is $324.88 per MW-day, including all RPM auctions for the 2026/2027 Delivery Year. The weighted average capacity price for the 2027/2028 Delivery Year is $333.44 per MW-day, including all RPM auctions for the 2027/2028 Delivery Year.
- For the 2025/2026 Delivery Year, RPM annual charges to load are $14.9 billion.
- In the 2027/2028 RPM Base Residual Auction, the market performance was determined to be not competitive.

26 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).
27 See OATT Attachment DD § 6.5.
28 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).
29 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).

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 2026 was 8.6 percent, an increase from 6.0 percent in the first three months of 2025.[30]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor in the first three months of 2026 was 84.4 percent, a decrease from 86.1 percent in the first three months of 2025.

Recommendations[31]

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.[32] [33] (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.[34] (Priority: Medium. First reported 2016. Status: Adopted 2024.)[35]
- 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.)[36]
- 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.)

30 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 22, 2026. 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.

31 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.

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

33 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).

34 "PJM Manual 19: Load Forecasting and Analysis," § 3.2 Development of the Forecast, Rev. 38 (Dec. 17, 2025).

35 See 189 FERC ¶ 61,095 (2024).

36 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).

- The MMU recommends that PJM's application of the ELCC approach be replaced with an ELCC approach that is based on the actual hourly availability of all individual generators for accreditation and for payment. The MMU recommends short term modifications to PJM's approach 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 inflexible class capacity accreditation ratings derived from a small number of nonrepresentative hours of poor performance from PV1 and WSE. (Priority: High. First reported 2023. Status: Not adopted.)

Market Design and Parameters

- The MMU recommends that PJM establish a load queue for large new data center loads to ensure that such loads are not added until there is adequate generation capacity to serve them. The MMU recommends that an expedited queue option that would permit both the load and the generation to be added without delays be available to large data centers if they bring their own new generation with locational and temporal characteristics reasonably matched to their load profile. (Priority: High. First reported Q2, 2025. Status: Not adopted.)
- 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 2024. Status: Adopted 2025.)
- 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.)[37]
- 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.)

37 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>.

- 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 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.) [38]
- 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.)[39]
- The MMU recommends that the RPM market power mitigation rules 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

38 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).

39 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).

and existing resources. (Priority: Medium. First reported 2017. Status: Not adopted.)[40]

- 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.)
- 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.[41] (Priority: High. First reported 2013. Status: Not adopted.)
- The only function the current MOPR is serving now is to create unnecessary administrative work in the application and compliance screening and to create barriers to entry for generation resources. Absent a meaningful change to MOPR, the MMU recommends eliminating the MOPR. (Priority: High. First reported 2025. 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

40 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).

41 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).

offers in the capacity market. (Priority: High. First reported 2016. Status: Not adopted.)

- The MMU recommends that the PJM Tariff be modified to explicitly state that in order to qualify, a Capacity Market Seller requesting a must offer exception based on a financially and physically firm commitment to an external sale of its capacity must provide a confirmed firm transmission reservation, covering the entire path from source to sink, for the full requested ICAP MW of the external sale that covers the entire delivery year, by the tariff defined deadline. The MMU recommends that this language apply to all external sales of Generation Capacity Resources, including those where an external balancing authority does not require this level of transmission service in order to consider a PJM resource as a network resource. (Priority: High. First reported 2025. Status: Not adopted.)

Deactivations/Retirements

- The MMU recommends that the notification requirement for deactivations be extended from the current one quarter prior (See Table 5-31) 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 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 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 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 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, until a decision is made to build transmission as a replacement, and then should be included. (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.)

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 2026/2027 RPM Base Residual Auction were significantly affected by flawed market design elements including the lack of a queue for the addition of large new data center loads, by the performance assessment interval (PAI) penalties that are part of the CP design, by PJM's ELCC approach, by the definition of market seller offer caps, by the failure to extend the RPM must offer requirement to demand resources, and by the product definition and lack of market power mitigation for demand 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. PJM filed changes that were approved by FERC and included in the 2026/2027 BRA 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, although PJM failed to include elimination of the categorical exemption for demand resources.[42] [43]

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 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.

42 See Letter Order, FERC Docket No. ER25-682-001 (April 29, 2025).
43 190 FERC ¶ 61,117 (2025).

The basic conclusion of Part A of the MMU's analysis of the 2026/2027 BRA is that data center load growth is the primary reason for recent and expected capacity market conditions, including total forecast load growth, the tight supply and demand balance, and high prices. But for data center growth, both actual and forecast, the PJM Capacity Market would not have seen the same tight supply demand conditions, the same high prices observed in the 2025/2026 BRA and 2026/2027 BRA or the currently expected tight supply conditions and high prices for subsequent capacity auctions. The combined total increase in capacity market revenues resulting from data center load, both actual and forecast, for the 2025/2026 BRA and the 2026/2027 BRA was $16,603,301,829.[44] [45] This total will continue to grow until the issues associated with the additions of large data center loads are addressed.

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

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

Data center load growth is the core reliability issue facing PJM markets at present. There is still time to address the issue but failure to do so will result in very high costs for other PJM customers and could also result in a switch

44 *See*, "Analysis of the 2025/2026 RPM Base Residual Auction - Part G Revised," <https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_2025 2026_RPM_Base_Residual_Auction_Part_G_20250603_Revised.pdf> (June 3, 2025).
45 See "Analysis of the 2026/2027 RPM Base Residual Auction - Part A," ("Part A") <https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20262027_RPM_Base_Residual_Auction_Part_A_20251001.pdf> (October 1, 2025).

from competitive markets to cost of service regulation or other distortions of the market design. Customers are already bearing billions of dollars in higher costs as a direct result of existing and forecast data center load as the Market Monitor demonstrated in Part G of the 2025/2026 BRA Analysis report and Part A of the 2026/2027 BRA Analysis Report.[46] [47]

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

For the first time since the introduction of the RPM capacity market design, the 2026/2027 BRA used a VRR curve with both a defined maximum price and a defined minimum price. The maximum and minimum prices were based on the Agreement between Governor Shapiro of Pennsylvania and PJM that was incorporated in a PJM filing with FERC.[48] That VRR curve with the defined maximum and minimum price is referred to in this report as the actual (or restricted) VRR curve. The VRR curve that would have been used absent the Agreement is referred in this report as the unrestricted VRR curve.

The Agreement resulted in a reduction of 2026/2027 BRA revenues of $3,169,915,210, or 16.4 percent, compared to the revenues that would have resulted from the unrestricted VRR curve, holding everything else constant. If the 2026/2027 BRA had been run with an unrestricted VRR curve, total revenues would have been $19,294,286,100, an increase of $3,169,915,210, or 19.7 percent, compared to the actual auction revenues of $16,124,370,889. The Agreement resulted in a reduction of 2027/2028 BRA revenues of $9,913,272,621, or 37.7 percent, compared to the revenues that would have resulted from the unrestricted VRR curve, holding everything else constant. If the 2027/2028 BRA had been run with an unrestricted VRR curve, total revenues would have been $26,324,850,846, an increase of $9,913,272,621, or 60.4 percent, compared to the actual auction revenues of $16,411,578,225. The Agreement resulted in a reduction of combined 2026/2027 and 2027/2028 BRA revenues of $13,083,187,831, or 28.7 percent, compared to the revenues that would have resulted from the unrestricted VRR curve, holding everything else constant.

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 2026/2027 RPM Base Residual Auction, total reserves were 21,353.2 MW, which is 208.7 MW (UCAP) short of the required reserve level of 21,561.9 MW (UCAP). The level of committed demand resources in the 2026/2027 BRA was 5,530.6 MW, meaning the PJM markets will rely on demand resources as part of the required reserve margin, rather than as excess above the required reserve margin. 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

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

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

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

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 have significantly under performed during recent cold weather and hot weather events. DR capacity resources do not have a defined market seller offer cap. PJM markets for the first time in the 2025/2026 and 2026/2027 Delivery Years 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 the 2025/2026 and 2026/2027 Delivery Years 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 related to demand resources. The RPM must offer requirement is not applied to demand resources. There are no market power mitigation rules that apply to demand resources.

For the 2026/2027 BRA, all participants to which the three pivotal supplier (TPS) test was applied (in the RTO RPM market) 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.[49] [50]

The correct definition of a competitive offer in the capacity market is the marginal cost of capacity, net ACR, where gross 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, and net ACR includes all energy and ancillary services net revenues as an offset against every element of gross ACR.

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 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 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. There is no effective performance incentive remaining in the capacity market. In the absence of the EFORd design and with the absence of actual or expected regular PAI events, there is no capacity market consequence for failing to perform.

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

49 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.

50 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).

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.[51] [52] [53] [54] [55] [56] [57] [58] [59] [60] [61] [62] [63] [64] In 2025 and the first three months of 2026, 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 57,618.3 MW of additional capacity that cleared in RPM auctions for the 2007/2008 through 2024/2025 Delivery Years, 43,653.8 MW (76.0 percent) were based on market funding. Of the 22,187.4 MW of additional capacity that cleared in RPM auctions for the 2025/2026 through the 2027/2028 Delivery Years, 18,225.0 MW (82.1 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 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.

51 See "Analysis of the 2018/2019 RPM Base Residual Auction Revised," (July 6, 2016) <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20182019_RPM_Base_Residual_Auction_20160706.pdf>
52 See "Analysis of the 2019/2020 RPM Base Residual Auction Revised," (August 31, 2016) <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20192020_RPM_BRA_20160831-Revised.pdf>.
53 See "Analysis of the 2020/2021 RPM Base Residual Auction," (November 11, 2017) <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Analysis_of_the_20202021_RPM_BRA_20171117.pdf>.
54 See "Analysis of the 2021/2022 RPM Base Residual Auction - Revised," (August 24, 2018) <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf>.
55 See "Analysis of the 2022/2023 RPM Base Residual Auction," (February 22, 2022) <https://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20222023_RPM_BRA_20220222.pdf>.
56 See "Analysis of the 2023/2024 RPM Base Residual Auction," (October 28, 2022) <https://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf>.
57 See the "Analysis of the 2024/2025 RPM Base Residual Auction," (October 30, 2023) <https://www.monitoringanalytics.com/reports/Reports/2023/IMM_Analysis_of_the_20242025_RPM_Base_Residual_Auction_20231030.pdf>.
58 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2017," (December 14, 2017) <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Report_on_Capacity_Replacement_Activity_4_20171214.pdf>.
59 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," (September 13, 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>.
60 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>.
61 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>.
62 See Monitoring Analytics, L.L.C., Analysis of the 2025/2026 Base Residual Auction, Parts A through H, <https://www.monitoringanalytics.com/reports/Reports/2024.shtml> and <https://www.monitoringanalytics. com/reports/Reports/2025.shtml>.
63 See "Analysis of the 2026/2027 RPM Base Residual Auction - Part A," (October 1, 2025) <https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20262027_RPM_Base_Residual_Auction_Part_A_20251001.pdf>.
64 See "Analysis of the 2027/2028 RPM Base Residual Auction – Part A," (January 5, 2026) <https://www.monitoringanalytics.com/reports/Reports/2026/IMM_Analysis_of_the_20272028_RPM_Base_Residual_Auction_Part_A_20260105.pdf>.

Table 5-2 RPM related MMU reports: 2025 through March 2026

Date	Name
January 6, 2025	IMM Comments re Capacity Market Rules Docket No. ER25-682 https://www.monitoringanalytics.com/filings/2025/IMM_Comments_Docket_No_ER25-682_20250106.pdf
January 10, 2025	IMM Comments re Must Offer Exemption for Capacity Resources Docket No. ER25-785 https://www.monitoringanalytics.com/filings/2025/IMM_Comments_Docket_No_ER25-785_20250110.pdf
January 14, 2025	IMM Answer to Motion to Extend re PA BRA Complaint Docket No. EL25-46 https://www.monitoringanalytics.com/filings/2025/IMM_Answer_to_Motion_to_Extend_Docket_No_EL25-46_20250114.pdf
January 23, 2025	IMM Comments re JCA Capacity Complaint Docket No. EL25-18 https://www.monitoringanalytics.com/filings/2025/IMM_Comments_Docket_No_EL25-18_20250123.pdf
January 31,2025	Analysis of the 2025/2026 RPM Base Residual Auction - Part E https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_E_20250131.pdf
February 4, 2025	Analysis of the 2025/2026 RPM Base Residual Auction - Part F https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_F_20250204.pdf
February 7, 2025	PA/PJM Agreement re Maximum and Minimum RPM Prices https://www.monitoringanalytics.com/reports/Presentations/2025/IMM_MC_PA_PJM_Agreement_Max_Min_RPM_Prices_20250207.pdf
February 7, 2025	Data Submission Window Opening for the 2026/2027 RPM Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Opening_2026-2027_RPM_Base_Residual_Auction_20250207.pdf
February 10,2025	IMM Answer to PJM re Capacity Market Rules Docket No. ER25-682 https://www.monitoringanalytics.com/filings/2025/IMM_Answer_to_PJM_Answer_Docket_No_ER25-682_20250210.pdf
February 18, 2025	IMM Answer re Must Offer Exemption for Capacity Resources Docket No. ER25-785 https://www.monitoringanalytics.com/filings/2025/IMM_Answer_to_Answer_Docket_No_ER25-785_20250218.pdf
February 25, 2025	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2025/2026 Delivery Year https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Notice_re_RPM_Must_Offer_Obligations_20250225.pdf
March 6,2025	Data Submission Window Opening for the 2026/2027 RPM Base Residual Auction - Updated https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Opening-20262027_Base_Residual_Auction_Updated_2_20250306.pdf
March 17, 2025	IMM Comments re PJM VRR Docket Nos. ER25-1357 and EL25-46, not consolidated https://www.monitoringanalytics.com/filings/2025/IMM_Comments_Docket_Nos_ER25-1357_and_EL25-46_20250317.pdf
March 19, 2025	IMM Request for Rehearing re Market Seller Offer Caps for Capacity Resources Docket No. ER25-785 https://www.monitoringanalytics.com/filings/2025/IMM_Request_for_Rehearing_Docket_No_ER25-785_20250319.pdf
April 10, 2025	IMM Determinations Posted for the PJM 2026/2027 RPM Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Determinations_on_RPM_Requests_2026-2027_Base_Residual_Auction_Revised_20250410.pdf
May 9, 2025	IMM Comments re Mitigating Variability in ELCC Accreditation between RPM Auctions Docket No. ER25-2002 https://www.monitoringanalytics.com/filings/2025/IMM_Comments_Docket_No_ER25-2002_20250509.pdf
May 19, 2025	Quadrennial Review Issues https://www.monitoringanalytics.com/reports/Presentations/2025/IMM_MIC_Quadrennial_Review_20250519.pdf
May 28, 2025	IMM Answer re Warrior Run Waiver Request Docket No. ER25-2197 https://www.monitoringanalytics.com/filings/2025/IMM_Answer_re_Warrior_Run_Docket_No_ER25-2197_20250528.pdf
May 28, 2025	IMM Answer re Sayreville Waiver Request Docket No. ER25-2162 https://www.monitoringanalytics.com/filings/2025/IMM_Answer_re_Sayreville_Docket_No_ER25-2162_20250528.pdf
May 28, 2025	IMM Answer re Morgantown Waiver Request Docket No. ER25-2190 https://www.monitoringanalytics.com/filings/2025/IMM_Answer_re_Morgantown_Docket_No_ER25-2190_20250228.pdf
June 3, 2025	Analysis of the 2025/2026 RPM Base Residual Auction – Part G Revised https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_G_20250603_Revised.pdf
June 9, 2025	IMM Comments re NCEMC Complaint Docket No. EL25-79 https://www.monitoringanalytics.com/filings/2025/IMM_Comments_Docket_No_EL25-79_20250609.pdf
June 9, 2025	IMM Answer to Answer re PJM BRA ELCC Values Docket No. ER25-2002 https://www.monitoringanalytics.com/filings/2025/IMM_Answer_to_Answer_Docket_No_ER25-2002_20250609.pdf
June 16, 2025	IMM Answer to PJM Answer re PJM BRA ELCC Values Docket No. ER25-2002 https://www.monitoringanalytics.com/filings/2025/IMM_Answer_to_PJM_Docket_No_ER25-2002_20250616.pdf
June 30, 2025	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2026/2027 Delivery Year https://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Notice_re_RPM_Must_Offer_Obligations_20250630.pdf
June 30, 2025	Quadrennial Review Proposal and Issues https://www.monitoringanalytics.com/reports/Presentations/2025/IMM_MIC_Quadrennial_Review_Issues_20250630.pdf
July 7, 2025	Data Submission Window Opening for the 2027/2028 RPM Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Data_Submission_Window_Opening_2027-2028_RPM_Base_Residual_Auction_20250707.pdf
July 8, 2025	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2026/2027 Delivery Year https://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Notice_re_RPM_Must_Offer_Obligations_20250708.pdf
July 9, 2025	Quadrennial Review Issues https://www.monitoringanalytics.com/reports/Presentations/2025/IMM_MIC_Quadrennial_Review_Issues_20250709.pdf
July 7, 2025	Data Submission Window Opening for the 2027/2028 RPM Base Residual Auction (PDF) https://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Data_Submission_Window_Opening_2027-2028_RPM_Base_Residual_Auction_20250707.pdf
July 8, 2025	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2026/2027 Delivery Year (PDF) https://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Notice_re_RPM_Must_Offer_Obligations_20250708.pdf
July 11, 2025	Executive Summary for the IMM ELCC Proposal https://www.monitoringanalytics.com/reports/Presentations/2025/IMM_ELCCSTF_IMM_Executive_Summary_IMM_Proposal_20250711.pdf
July 15, 2025	IMM Answer re EE PIMV Reports Docket No. EL25-87 https://www.monitoringanalytics.com/filings/2025/IMM_Answer_Docket_No_EL25-87_20250715.pdf
July 25, 2025	IMM Response to PJM ELCC Memo (PDF)https://www.monitoringanalytics.com/reports/Presentations/2025/IMM_ELCCSTF_IMM_Response_20250725.pdf
July 31, 2025	Analysis of the 2025/2026 RPM Base Residual Auction - Part H (PDF) https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_H_20250731.pdf
August 22, 2025	IMM Quadrennial Review Proposal (PDF) https://www.monitoringanalytics.com/reports/Presentations/2025/IMM_MIC_Quadrennial_Review_IMM_Gross_and_Net_CONE_20250822.pdf
September 2, 2025	IMM Comments re Large Load Additions CIFP (PDF) https://www.monitoringanalytics.com/reports/Presentations/2025/IMM_CIFP_Large_Load_Additions_Comments_re_CIFP_scope_20250827.pdf
September 5, 2025	IMM Determinations Posted for the PJM 2027/2028 RPM Base Residual Auction (PDF) https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Determinations_on_RPM_Requests_2027-2028_Base_Residual_Auction_20250905.pdf
September 8, 2025	IMM Protest re Dairyland Waiver Request Docket No. ER25-3124 (PDF) https://www.monitoringanalytics.com/filings/2025/IMM_Protest_Waiver_Request_Docket_No_ER25-3124_20250908.pdf
September 10, 2025	IMM Gross and Net CONE Impact of Extended Project Schedule (PDF) https://www.monitoringanalytics.com/reports/Presentations/2025/IMM_MIC_Gross_and_Net_CONE_Impact_of_Extended_Project_Schedule_20250910.pdf
September 24, 2025	IMM Protest re Cordova RPM Must Offer Waiver Request Docket No. ER25-3375 (PDF) https://www.monitoringanalytics.com/filings/2025/IMM_Protest_Docket_No_ER25-3375_20250924.pdf
September 25, 2025	Quadrennial Review Issues (PDF) https://www.monitoringanalytics.com/reports/Presentations/2025/IMM_MRC_MC_Quadrennial_Review_Issues_20250925.pdf
September 26, 2025	Data Submission Window Opening for the 2026/2027 RPM Third Incremental Auction (PDF) https://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Data_Submission_Window_Opening_2026-2027_Third_Incremental_Auction_20250926.pdf

Continued

Date	Name
October 10, 2025	Analysis of the 2026/2027 RPM Base Residual Auction - Part A (PDF) https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20262027_RPM_Base_Residual_Auction_Part_A_20251001.pdf
October 14, 2025	IMM CIFP Large Load Additions Proposal Memo (PDF) https://www.monitoringanalytics.com/reports/Presentations/2025/IMM_CIFP_LLA_Proposal_Memo_20251014.pdf
October 14, 2025	IMM CIFP Large Load Additions (LLA) Proposal Presentation (PDF) https://www.monitoringanalytics.com/reports/Presentations/2025/IMM_CIFP_LLA_Proposal_Presentation_20251014.pdf
October 16, 2025	IMM Answer and Motion for Leave to Answer re Dairyland Power Cooperative Waiver Request Docket No. ER25-3124 (PDF) https://www.monitoringanalytics.com/filings/2025/IMM_Answer_Docket_No_ER25-3124_20251016.pdf
October 22, 2025	IMM Bowring Testimony re PAPUC Public Hearing HB1834 (PDF) https://www.monitoringanalytics.com/filings/2025/IMM_PAPUC_Bowring_Testimony_HB1834_20251022.pdf
October 28, 2025	IMM Comments re Voltus/Mission:data Complaint Docket No. EL26-4 (PDF) https://www.monitoringanalytics.com/filings/2025/IMM_Comments_Docket_No_EL26-4_20251028.pdf
November 4, 2025	IMM Answer to Answer re PECO-Amazon TSA Docket No. ER25-3492 (PDF) https://www.monitoringanalytics.com/filings/2025/IMM_Answer_to_Answer_Docket_No_ER25-3492_20251104.pdf
November 5, 2025	M18 Revisions: Issues for DER in RPM Auctions (PDF) https://www.monitoringanalytics.com/reports/Presentations/2025/IMM_MIC_M18_Revisions_DER_in_RPM_Auctions_20251105.pdf
November 10, 2025	IMM Protest re Susquehanna CIR Waiver Docket No. ER26-313 (PDF) https://www.monitoringanalytics.com/filings/2025/IMM_Comments_Docket_No_ER26-313_20251110.pdf
November 10, 2025	IMM Proposal CIFP Executive Summary (PDF) https://www.monitoringanalytics.com/reports/Presentations/2025/IMM_CIFP_Executive_Summary_20251110.pdf
November 25, 2025	IMM Determinations Posted for the PJM 2026/2027 RPM Third Incremental Auction (PDF) https://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Determinations_on_RPM_Requests-2026-2027_Third_Incremental_Auction_20251125.pdf
November 25, 2025	IMM Comments re Large Load Additions ANOPR Docket No. RM26-4 (PDF) https://www.monitoringanalytics.com/filings/2025/IMM_Comment_Docket_No_RM26-4_20251125.pdf
November 25, 2025	IMM Complaint re Large Load Additions Docket No. EL26-30 (PDF) https://www.monitoringanalytics.com/filings/2025/IMM_Complaint_re_Data_Center_Loads_Docket_No_EL26-XX_20251125.pdf
November 26, 2025	IMM Protest, Motion for Leave to Answer and Answer re AEP FRR Waiver Request Docket No. ER26-444 (PDF) https://www.monitoringanalytics.com/filings/2025/IMM_Comments_Docket_No._ER26-444_20251126.pdf
December 3, 2025	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2026/2027 and 2027/2028 Delivery Years (PDF) https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Notice_re_RPM_Must_Offer_Obligations_20251203.pdf
December 3, 2025	Advanced Commitments Design Components https://www.monitoringanalytics.com/reports/Presentations/2025/IMM_MIC_Advanced_Commitments_Design_Components_20251203.pdf
December 5, 2025	IMM Reply Comments re Large Load Additions ANOPR Docket No. RM26-4-000 (PDF) https://www.monitoringanalytics.com/filings/2025/IMM_Reply_Comments_re_ANOPR_Docket_No_RM26-4_20251205.pdf
December 8, 2025	IMM Protest re Quadrennial Review VRR Curve Docket No. ER26-455 (PDF) https://www.monitoringanalytics.com/filings/2025/IMM_Protest_re_PJM_205_Docket_No_ER26-455_20251208.pdf
December 19, 2025	IMM Answer to Answers re IMM Large Load Complaint Docket No. EL26-30 (PDF) https://www.monitoringanalytics.com/filings/2025/IMM_Answer_to_Answers_Docket_No_EL26-30_20251219.pdf
January 5, 2026	Analysis of the 2027/2028 RPM Base Residual Auction – Part A (PDF) https://www.monitoringanalytics.com/reports/Reports/2026/IMM_Analysis_of_the_20272028_RPM_Base_Residual_Auction_Part_A_20260105.pdf
January 9, 2026	IMM Comments re Economic Load Response Regulation Only Participants Docket No. ER26-846 (PDF) https://www.monitoringanalytics.com/filings/2026/IMM_Answer_to_Economic_Load_Response_Regulation_Only_Participants_Docket_No_ER26-846_20260109.pdf
January 12, 2026	IMM Answer to PJM re Warrior Run Waiver Request Docket No. ER26-880 (PDF) https://www.monitoringanalytics.com/filings/2026/IMM_Answer_to_PJM_Docket_No_ER26-880_20260112.pdf
January 12, 2026	RMR Matrix Issues: Scope Areas 4, 5 and 6 (PDF) https://www.monitoringanalytics.com/reports/Presentations/2026/IMM_DESTF_RMR_Matrix_Issues_Scope_Areas_4_5_6_20260112.pdf
January 20, 2026	IMM Answer to PJM re Quadrennial Review VRR Curve Docket No. ER26-455 (PDF) https://www.monitoringanalytics.com/filings/2026/IMM_Answer_to_PJM_Answer_Docket_No_ER26-455_20260120.pdf
January 20, 2026	DR Nonperformance Penalties (PDF) https://www.monitoringanalytics.com/reports/Presentations/2026/IMM_MIC_DR_Nonperformance_Penalties_20260120.pdf
January 28, 2026	Supply Uncertainty (PDF) https://www.monitoringanalytics.com/reports/Presentations/2026/IMM_RCSTF_Supply_Uncertainty_20260128.pdf
February 4, 2026	DR Nonperformance Penalty and Performance Adjustment Factor Example (PDF) https://www.monitoringanalytics.com/reports/Presentations/2026/IMM_MIC_Nonperformance_Penalty_and_Performance_Adjustment_Factor_Examples_20260204.pdf
February 5, 2026	IMM Answer to CEG re Co-located Load Docket No. EL25-49, et al (PDF) https://www.monitoringanalytics.com/filings/2026/IMM_Answer_to_CEG_RFC_Docket_No_EL25-49_et_al_20260205.pdf
February 17, 2026	IMM Backstop Auction Design Proposal (PDF) https://www.monitoringanalytics.com/reports/Presentations/2026/IMM_Reliability_Backstop_WS_Backstop_Auction_Design_Proposal_20260217.pdf
February 25, 2026	Reliability Backstop Auction Design Proposal –V2 (PDF) https://www.monitoringanalytics.com/reports/Presentations/2026/IMM_Reliability_Backstop_WS_%20Backstop_Auction_Design_Proposal-V2_20260224.pdf
March 3, 2026	Analysis of the 2026/2027 RPM Base Residual Auction – Part B (PDF) https://www.monitoringanalytics.com/reports/Reports/2026/IMM_Analysis_of_the_20262027_RPM_Base_Residual_Auction_Part_B_20260303.pdf
March 11, 2026	DR Penalties Matrix Additions (PDF) https://www.monitoringanalytics.com/reports/Presentations/2026/IMM_MIC_DR_penalties_matrix_additions_20260311.pdf
March 20, 2026	IMM Comments re PJM Price Collar Extension Docket No. ER26-1556 (PDF) https://www.monitoringanalytics.com/filings/2026/IMM_Comments_Docket_No_ER26-1556_20260320.pdf
March 25, 2026	IMM Reply Brief re Co-Location Order Paper Hearing Docket No. EL25-49, et al (PDF) https://www.monitoringanalytics.com/filings/2026/IMM_Reply_Brief_Docket_No_EL25-49_et_al_20250325.pdf
April 6, 2026	IMM Answer to Answer re PJM Price Collar Extension Docket No. ER26-1556 (PDF) https://www.monitoringanalytics.com/filings/2026/IMM_Answer_Docket_No_ER26-1556_20260406.pdf
April 22, 2026	IMM Comments on Proposed DR Penalties (PDF) https://www.monitoringanalytics.com/reports/Presentations/2026/IMM_MRC_Comments_on_Proposed_DR_Penalties_20260422.pdf

Market Design

With the earlier introduction of the Capacity Performance model and the recent introduction of the ELCC model, combined with a tightening of the capacity supply and demand balance in ICAP terms, it is clear that PJM's choices about the details of market design have a potentially dominant impact on capacity market outcomes in PJM. The ongoing decision to allow the addition of a significant number of large new data center loads that cannot be served reliably due to inadequate capacity is the most recent and most significant example.

RPM prices are locational by LDA and may vary depending on transmission constraints into LDAs and local supply and demand conditions.[65] The capacity market is not fully locational. The capacity market locational differences exist only between and among LDAs. The capacity market design assumes that there are no transmission or operational constraints within LDAs and treats all capacity resources within an LDA as perfect substitutes even when they are not. The lack of a fully locational design is a market design flaw that has resulted in the designation of units as RMRs based on internal constraints that were not recognized in the market clearing process. Existing generation that qualifies as a capacity resource must be offered into RPM auctions, except for categorically exempt demand resources, and except for resources in a fixed resource requirement (FRR) plan. All load is required to pay for capacity. Participation by LSEs is mandatory, except for those entities that elect the FRR option. There is an administratively determined demand curve that defines scarcity pricing levels and that, with the supply curve derived from capacity offers, determines market prices in each BRA. There are explicit market power mitigation rules that define structural market power, that define offer caps based on the marginal cost of capacity, and that have flexible criteria for competitive offers by new entrants. Demand resources may be offered directly into RPM auctions but do not have a requirement to be identifiable physical resources, do not have a must offer obligation, do not have a corresponding must offer obligation in the energy market for cleared resources, do not have market seller offer caps, and receive the clearing price.

65 Transmission constraints are local capacity import capability limitations (low capacity emergency transfer limit (CETL) margin over capacity emergency transfer objective (CETO)) caused by transmission facility limitations, voltage limitations or stability limitations.

The results of the 2026/2027 RPM Base Residual Auction were significantly affected by flawed market design elements including the lack of a queue for the addition of large new data center loads, by the performance assessment interval (PAI) penalties that are part of the CP design, by PJM's ELCC approach, by the definition of market seller offer caps, by the failure to extend the RPM must offer requirement to demand resources, and by the product definition and lack of market power mitigation for demand 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. PJM filed changes that were approved by FERC and included in the 2026/2027 BRA 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, although PJM failed to include elimination of the categorical exemption for demand resources.

The fundamental mistake of the CP design was to attempt to recreate energy market incentives in the capacity market. The CP model was an explicit attempt to bring energy market shortage pricing into the capacity market design. The CP model was designed on the unsupported assumption that shortage prices in the energy market were not high enough and needed to be increased via the capacity market. The CP design focused on a small number of critical hours (performance assessment hours or PAH, translated into five minute intervals as PAI) and imposed large penalties on generators that failed to produce energy only during those hours. The use of capacity market penalties rather than energy market incentives created a new risk. While there are differences of opinion about how to value the risk, this CP risk is not risk that is fundamental to the operation of a wholesale power market. This is risk created by the CP design in order to provide an incentive to produce energy during high demand hours that is even higher than the energy market incentive, amplified by an operating reserve demand curves (ORDC). The risk created by CP is not limited to risk for individual generators, but extends to the viability of the market. If penalties create bankruptcies that threaten the viability of required energy output from the affected units, there is a risk to the market.

The CP PAI incentives are not effective market incentives. PAI incentives are administrative and nonmarket incentives that are not compatible with an effective market design. The energy market clearing, in contrast, is transparent and efficient and timely. While there are issues with the details of energy market pricing that must be addressed, including shortage pricing, the energy market does not include or create the significant and long lasting uncertainty created by the PAI rules as exhibited most dramatically by the results of Winter Storm Elliott. The PAI design creates an administrative process that adds unacceptable uncertainty to the process and that can never approach the effectiveness of the energy market in providing price signals and timely settlement. In addition, the imposition of PAI penalties on intermittent resources when those resources cannot perform is illogical.

The MMU recommends that PJM's application of the ELCC approach be replaced with an ELCC approach that is based on the actual hourly availability of all individual generators for accreditation and for payment. The MMU recommends short term modifications to PJM's approach 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 inflexible class capacity accreditation ratings derived from a small number of nonrepresentative hours of poor performance from PV1 and WSE. In the short run capacity accreditation should eliminate the performance during PV1 and WSE and should recognize the winter capability of thermal resources rather than limiting such resources to summer ratings. Most of the risk recognized in the ELCC model is winter risk but the ELCC accreditation values for thermal resources are capped at the summer ratings. That unnecessarily limits supply and changes the ELCC values for all other resources and changes the system accredited unforced capacity and therefore AUCAP, the maximum level of load that can be served by the existing resources and therefore the reliability requirement. The CIRs of such resources are currently limited by the summer ratings but those rules can and should be changed given the use of the ELCC approach. There is no reason that excess winter CIRs cannot be assigned to these resources immediately.

The initial VRR curve, introduced in 2007, had a maximum price equal to 1.5 times the Net Cost of New Entry (Net CONE), determined annually based on the fixed cost of new generating capacity, or Gross Cost of New Entry (Gross CONE), net of the three year average energy and ancillary service revenues. That VRR curve was structured to yield auction clearing prices equal to the 1.5 times Net CONE when the amount of capacity cleared was less than 99 percent of the target reserve margin, and below 1.5 times Net CONE when the amount of capacity cleared was greater than 99 percent of the target reserve margin. The use of Net CONE was based on the logic of the capacity market, to ensure that the cost of entry was covered between the energy and capacity markets. Net CONE was the missing money that needed to be recoverable in the capacity market. Net CONE was the equilibrating factor between the capacity market and energy market. The use of Gross CONE is inconsistent with that basic capacity market logic. Gross CONE was introduced as the maximum price based on concerns that Net CONE would be too low. The maximum point on the VRR curve for the 2025/2026 BRA was the higher of Gross CONE or 1.5 times Net CONE and Gross CONE was used. For the first time since the introduction of the RPM capacity market design, the 2026/2027 BRA used a VRR curve with both a defined maximum price and a defined minimum price.[66] However, if the logic of the markets implies a low Net CONE, that is the right answer. There is nothing inherently wrong with a low Net CONE that requires abandoning the basic capacity market logic. The use of Gross CONE rather than 1.5 times Net CONE was an intervention designed to increase capacity market prices despite the fact that the basic economic logic did not support that increase. If there is an issue with the calculation of Net CONE, it should be addressed directly rather than by ignoring its central role in the design of the capacity market. As Gross CONE numbers are reasonably well defined, much more focus on the correct calculation of the net revenues used in the forward auctions is required in order to ensure that market participants have confidence in the Net CONE values used in the auctions.

PJM ended the long standing categorical exemption of intermittent resources, capacity storage resources, and hybrid resources from the RPM must offer requirement. Consistent with the MMU's recommendations, that exemption

66 On April 21, 2025, FERC issued an order accepting PJM's proposal to establish a temporary capacity market price cap and floor for the 2026/2027 and 2027/2028 Delivery Years. 191 FERC ¶ 61,066 (April 21, 2025).

was eliminated for all but demand resources. There is no reason to continue to exempt demand resources from the RPM must offer requirement. The same rules should apply to all capacity resources. The purpose of the RPM must offer rule, which has been in place since the beginning of the capacity market in 1999, is to ensure that the capacity market works, and therefore that the energy market works, based on the inclusion of all demand and all supply, to ensure competitive entry, to ensure open access to the transmission system, and to prevent the exercise of market power via withholding of capacity supply.

For these reasons, existing resources are required to return CIRs to the market within one year after retirement. The MMU recommends that resources return CIRs to the market on the day of retirement.[67]

Consistent with the must offer obligation, performance penalties should not be applied to solar and wind resources when they are not capable of performing based on ambient conditions. For example, solar resources should be subject to performance penalties if they fail to perform when the sun is shining but should not be subject to performance penalties in the middle of the night. That would be the result under the incentive approach recommended by the MMU. If PAI is retained, this would be a rational application of the PAI penalties that recognizes the physical capabilities of resources and is therefore not discriminatory.

Demand resources (DR) have always been treated more favorably than generation capacity resources. Demand resources do not have an RPM must offer requirement. Demand resources, unlike all other capacity resources, are not subject to market seller offer caps to protect against the exercise of market power in the capacity market. When demand resources are pivotal, as they were for the 2026/2027 BRA, they have structural market power and can and do exercise market power. That conclusion does not depend on whether withholding directly benefits those resources through a portfolio effect. The result of the failure to offer can be a significant increase in the market price of capacity above the competitive level when that supply is pivotal. If the resources clear, it benefits the resources directly. Even if the resources do not clear, higher prices can benefit the owners of capacity portfolios that include such resources as well as resources with an RPM must offer requirement. The MMU recommends that demand resources have defined and enforced market seller offer caps in the capacity market, like all other capacity resources.

PJM filed tariff changes that transfer risk caused by the volatile ELCC ratings from generation owners to the load. ELCC ratings may increase or decrease significantly between the time a generator clears in the RPM Base Residual Auction and the final ELCC rating just prior to the start of the delivery year. Under the new tariff rules, generators will be excused from paying the Capacity Resource Deficiency Charge for a deficiency caused by a decrease in the final ELCC rating. Under the prior rules, a Capacity Market Seller was required to cover its short position by acquiring additional capacity or pay a deficiency penalty equal to 20 percent of the base residual auction clearing price for each MW of shortage. The tariff change was filed by PJM on April 18, 2025, and approved by FERC on June 17, 2025.[68] [69] The MMU opposed the change because the new rule does not mitigate the risk as asserted by PJM but simply transfers the ELCC rating volatility risk to the load.[70] The change is inconsistent with basic market logic under which investors bear the risk associated with the ownership of generation.

Installed Capacity

On January 1, 2026, RPM installed capacity was 184,220.8 MW (Table 5-3).[71] Over the next three months, new generation, unit deactivations, facility reratings, plus import and export shifts resulted in RPM installed capacity of 184,190.8 MW on March 31, 2026, a decrease of 30.0 MW or 0.0 percent from the January 1 level.[72] [73] The 30.0 MW decrease was the net result of new or

67 See Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER25-2162-000 (May 28, 2025); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER25-2190-000 (May 28, 2025); and Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER25-2197-000 (May 28, 2025).

68 *Proposal to Mitigate Impacts From Updates to ELCC Accreditation between the Base Residual Auction and the Final ELCC Accreditation Values*, PJM Interconnection L.L.C., Docket ER25-2002 (April 18, 2025).

69 191 FERC ¶ 61,203 (June 17, 2025).

70 See *Comments of the Independent Market Monitor for PJM* (May 9, 2025), *Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM* (June 9, 2025), *Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM* (June 16, 2025), Docket ER25-2002-000).

71 Percent values shown in Table 5-3 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

72 Unless otherwise specified, the capacity described in this section is the summer installed capacity rating of all PJM generation capacity resources, as entered into the Capacity Exchange system, regardless of whether the capacity cleared in the RPM auctions.

73 Wind resources accounted for 4,370.6 MW, and solar resources accounted for 8,559.8 MW of installed capacity in PJM on March 31, 2026. Prior to the 2023/2024 Delivery Year, PJM administratively reduced the capabilities of all wind generators to 14.7 percent for wind farms in mountainous terrain and 17.6 percent for wind farms in open terrain, and solar generators to 42.0 percent for ground mounted

reactivated generation (253.9 MW) and net capacity modifications (6.0 MW), offset by an increase in exports (0.2), derates (258.1 MW), and deactivations or changes in capacity resource status (31.6 MW).

At the beginning of the new delivery year on June 1, 2025, RPM installed capacity was 181,221.6 MW, an increase of 4,056.0 MW or 2.3 percent from the May 31, 2025, level of 177,165.6 MW. This change occurred as a result of deactivations, derates, capacity modifications, and import/export contracts beginning and/or ending at the start of the new delivery year.

Table 5-3 Installed capacity (By fuel source): January 1, January 31, February 28, and March 31, 2026[74] [75]

	01-Jan-26		31-Jan-26		28-Feb-26		31-Mar-26	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Battery	24.0	0.0%	24.0	0.0%	35.7	0.0%	35.7	0.0%
Coal	37,544.6	20.4%	37,544.6	20.4%	37,395.0	20.3%	37,394.8	20.3%
Gas	88,888.4	48.3%	88,888.4	48.2%	88,813.0	48.2%	88,812.9	48.2%
Hybird	10.2	0.0%	10.2	0.0%	10.2	0.0%	10.2	0.0%
Hydroelectric	8,215.2	4.5%	8,215.2	4.5%	8,168.1	4.4%	8,168.1	4.4%
Nuclear	32,176.2	17.5%	32,176.2	17.5%	32,163.6	17.5%	32,163.6	17.5%
Oil	4,066.5	2.2%	4,066.5	2.2%	4,065.7	2.2%	4,065.7	2.2%
Solar	8,315.7	4.5%	8,409.9	4.6%	8,559.8	4.6%	8,559.8	4.6%
Solid waste	609.4	0.3%	609.4	0.3%	609.4	0.3%	609.4	0.3%
Wind	4,370.6	2.4%	4,370.6	2.4%	4,370.6	2.4%	4,370.6	2.4%
Total	184,220.8	100.0%	184,315.0	100.0%	184,191.1	100.0%	184,190.8	100.0%

Figure 5-1 shows the share of installed capacity by fuel source for the first day of each delivery year, from June 1, 2007, to June 1, 2025, as well as the expected installed capacity for the 2026/2027 and 2027/2028 Delivery Years. On June 1, 2007, coal comprised 40.7 percent of the installed capacity, reached a maximum of 42.9 percent in 2012, decreased to 20.71 percent on June 1, 2025, and is projected to decrease to 17.0 percent on June 1, 2027. The share of gas increased from 29.1 percent on June 1, 2007, reached a maximum of 50.2 percent in 2024, decreased to 49.0 percent on June 1, 2025, and is projected to increase to 49.1 on June 1, 2027.

Figure 5-1 Percent of installed capacity (By fuel source): June 1, 2007 through June 1, 2027[76]

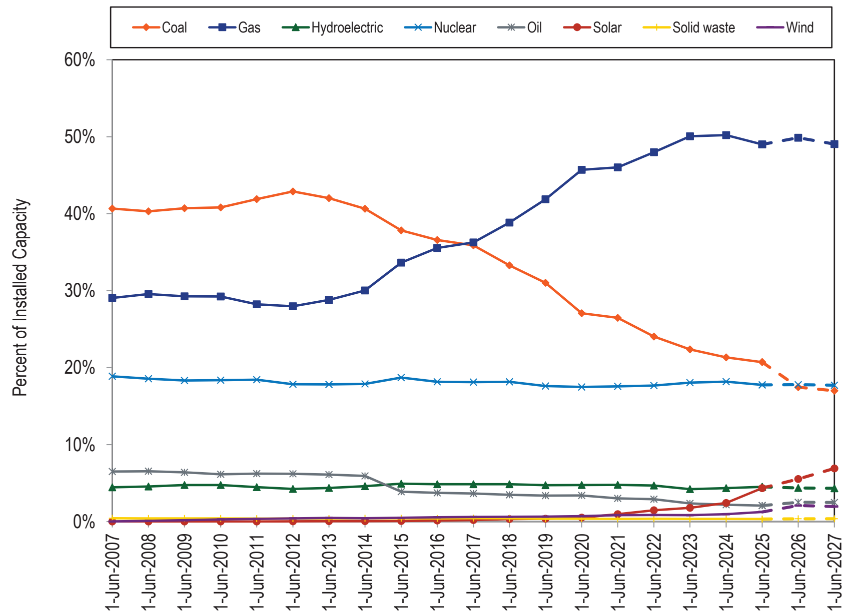


Table 5-4 shows the RPM installed capacity on January 1, 2026, through March 31, 2026, for the top five generation capacity resource owners, excluding FRR committed MW. Dominion Resources, Inc. was an FRR entity for the 2022/2023 through 2024/2025 Delivery Years and shifted their participation from FRR to RPM with the 2025/2026 Delivery Year.

fixed panel, 60.0 percent for ground mounted tracking panel, and 38.0 percent for other than ground mounted solar arrays, of nameplate capacity when determining the installed capacity because wind and solar resources cannot be assumed to be available on peak and cannot respond to dispatch requests. As data became available, unforced capability of wind and solar resources was to be calculated using actual data. There are additional wind and solar resources not reflected in total capacity because they are energy only resources and do not participate in the PJM Capacity Market. See "PJM Manual 21B: PJM Rules and Procedures for Determination of Generating Capability," § 4 Calculations of ELCC Class Rating, ELCC Resource Performance Adjustment, Accredited UCAP, and Accredited UCAP Factor, Rev. 05 (Jan. 22, 2026). The derating approach has been replaced with ELCC starting in the 2023/2024 Delivery Year.

74 The data for hybrid solar/battery resources are included in the solar data for confidentiality reasons.

75 Installed capacity is based on imports, exports, and PJM's capacity modification ("capmod") database that tracks new and reactivated generation, unit uprates and derates, and deactivations/changes to capacity resource status. Demand Resources are not tracked in this way and are not included here. For analysis of Demand Resources in the capacity market, see the Demand Resources discussion later in this section.

76 Prior to June 1, 2025, PJM set ICAP equal to UCAP for solar and wind units. Starting June 1, 2025, PJM began setting ICAP equal to CIRs for solar and wind units.

Table 5-4 Installed capacity by parent company: January 1, January 31, February 28, and March 31, 2026

	01-Jan-26			31-Jan-26			28-Feb-26			31-Mar-26		
Parent Company	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank
Dominion Resources, Inc.	21,947.0	12.8%	1	21,947.0	12.8%	2	21,959.4	12.9%	2	21,959.4	12.9%	2
Constellation Energy Generation, LLC	20,279.1	11.9%	2	24,446.8	14.3%	1	24,385.2	14.3%	1	24,385.2	14.3%	1
Vistra Energy Corp.	13,929.1	8.2%	3	13,929.1	8.1%	3	13,929.1	8.2%	3	13,928.4	8.2%	3
Talen Energy Corporation	12,673.1	7.4%	4	12,673.1	7.4%	4	12,669.2	7.4%	4	12,665.9	7.4%	4
LS Power Equity Partners, L.P.	10,667.9	6.2%	5	4,461.3	2.6%	8	4,451.4	2.6%	8	4,451.4	2.6%	8
NRG Energy, Inc.	1,949.0	1.1%	21	8,155.6	4.8%	5	8,155.6	4.8%	5	8,155.6	4.8%	5

The sources of funding for generation owners can be categorized as one of two types: market and nonmarket. Market funding is from private investors bearing the investment risk without guarantees or support from any public sources, subsidies or guaranteed payment by ratepayers. Providers of market funding rely entirely on market revenues. Nonmarket funding is from guaranteed revenues, including cost of service rates for a regulated utility and subsidies. Table 5-5 shows the RPM installed capacity on January 1, 2026, to March 31, 2026, by funding type.

Table 5-5 Installed capacity by funding type: January 1, January 31, February 28, and March 31, 2026

	01-Jan-26		31-Jan-26		28-Feb-26		31-Mar-26	
Funding Type	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP
Market	133,490.8	72.5%	133,585.0	72.5%	133,620.1	72.5%	132,347.7	71.9%
Nonmarket	50,730.0	27.5%	50,730.0	27.5%	50,571.0	27.5%	51,843.1	28.1%
Total	184,220.8	100.0%	184,315.0	100.0%	184,191.1	100.0%	184,190.8	100.0%

Fuel Diversity

Figure 5-2 shows the fuel diversity index (FDI_c) for RPM installed capacity.[77] The FDI_c is defined as , where s_i is the percent share of fuel type *i*. The minimum possible value for the FDI_c is zero, corresponding to all capacity from a single fuel type. The maximum possible value for the FDI_c is achieved when each fuel type has an equal share of capacity. For a capacity mix of eight fuel types, the maximum achievable index is 0.875. The fuel type categories used in the calculation of the FDI_c are in Table 5-3. FDI_c calculations prior to June 1, 2023 included eight fuel types. Batteries were added to the resource mix on June 1, 2023, and hybrid solar resources were added on January 1, 2024. The maximum achievable index with nine fuel types is 0.889. The maximum achievable index with ten fuel types is 0.900. The FDI_c is stable and does not exhibit any long-term trends. The only significant deviation occurred with the expansion of the PJM footprint. On April 1, 2002, PJM expanded with the addition of Allegheny Power System, which added about 12,000 MW of generation.[78] The reduction in the FDI_c resulted from an increase in coal capacity resources. A similar but more significant reduction occurred in 2004 with the expansion into the COMED, AEP, and DAY Control Zones.[79] The FDI_c on March 31, 2026 increased 2.3 percent in comparison with the FDI_c on March 31, 2025. Figure 5-2 also includes the expected FDI_c through March 31, 2027. The expected FDI_c is indicated in Figure 5-2 by the dotted orange line.

The FDI_c is used to measure the impact on fuel diversity of potential retirements in 2026 through 2030. A total of 10,963 MW of capacity are at risk of retirement, consisting of 8,330 MW currently planning to retire and 2,633 MW expected to be uneconomic.[80] The dotted green line in Figure 5-2 shows the FDI_c assuming that the capacity from the expected 2026 retirements

77 The MMU developed the FDI to provide an objective metric of fuel diversity. The FDI metric is similar to the HHI used to measure market concentration. The FDI is calculated separately for energy output and for installed capacity. The FDI_c includes derated capacity values for intermittent capacity subject to derating.

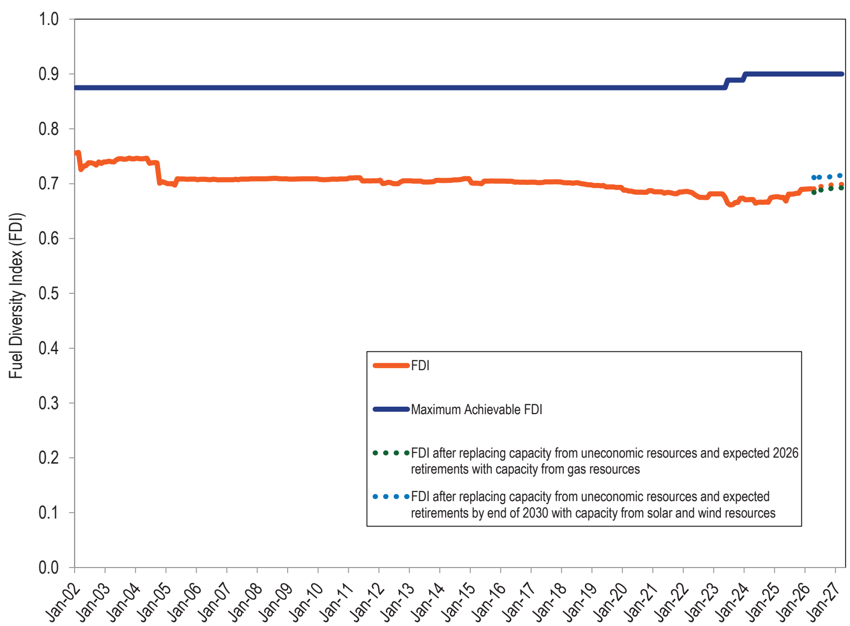
78 On April 1, 2002, the PJM Region expanded with the addition of Allegheny Power System under a set of agreements known as "PJM-West." See page 4 in the *2002 Annual State of the Market Report for PJM* for additional details.

79 See the *2019 Annual State of the Market Report for PJM*, Volume 2, Appendix A, "PJM Geography" for an explanation of the expansion of the PJM footprint. The integration of the COMED Control Area occurred in May 2004 and the integration of the AEP and DAY Control Zones occurred in October 2004.

80 See the *2025 Annual State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue.

were replaced by gas fired capacity.[81] The counterfactual FDI_c on March 31, 2027 under these assumptions is 0.9 percent lower than the expected FDI_c on March 31, 2027. The dotted blue line in Figure 5-2 shows the FDI_c assuming that the capacity from the expected retirements through 2030 were replaced by wind and solar capacity.[82] The counterfactual FDI_c on March 31, 2027 in this scenario is 2.3 percent higher.

Figure 5-2 Fuel Diversity Index for installed capacity: January 1, 2002 through March 31, 2027



81 It is assumed that all of the replacement capacity is from gas units. In previous reports, solar and wind capacity have also been used for replacement capacity with the amounts based on the expected increase in the PJM RPS obligation for the upcoming year. But the PJM RPS obligation will decrease in 2027 in comparison to 2026 due to the termination of the Ohio RPS in 2027.

82 The split between solar (80.6 percent) and wind (19.4 percent) is based on queue data. In previous reports, the replacement capacity included gas units in addition to solar and wind with the amount of solar and gas replacement capacity being based on the expected increase in the PJM RPS obligation in 2030 in comparison to current year. But the RPS increase for 2030 exceeds the expected retirements and only solar and wind are used for replacement capacity in this scenario.

RPM Capacity Market

The RPM Capacity Market, implemented June 1, 2007, is a three year forward looking, annual, locational market, with a must offer requirement for existing generation capacity resources, except for demand response resources, and except for resources owned by entities that elect the fixed resource requirement (FRR) option, and mandatory participation by load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand side resources.

The standard schedule is that annual base residual auctions are held in May for delivery years that are three years in the future. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[83] In the first three months of 2026, the 2026/2027 RPM Third Incremental Auction was conducted. The auction schedule has diverged significantly from the standard schedule in recent years.

Market Structure

Supply

Table 5-6 shows generation capacity changes since the implementation of the Reliability Pricing Model through the 2024/2025 Delivery Year. The 13,506.2 MW increase was the result of new generation capacity resources (46,491.1 MW), reactivated generation capacity resources (1,380.4 MW), uprates (9,746.8 MW), integration of external zones (21,967.5 MW), a net decrease in capacity exports (538.9 MW), offset by a net decrease in capacity imports (1,513.1 MW), deactivations (58,847.3 MW) and derates (6,258.1 MW).

Table 5-7 shows the calculated RPM reserve margin and reserve in excess of, or short of, the target installed reserve margin (IRM) for June 1, 2022, through June 1, 2027, and accounts for cleared capacity, replacement capacity, and deficiency MW for all auctions held and the most recent peak load forecast for each delivery year. The completion of the replacement process using cleared buy bids from RPM incremental auctions includes two transactions. The first

83 See Letter Order, Docket No. ER10-366-000 (January 22, 2010).

step is for the entity to submit and clear a buy bid in an RPM incremental auction. The next step is for the entity to complete a separate replacement transaction using the cleared buy bid capacity. Prior to the 2025/2026 Delivery Year, replacement capacity transactions can be completed only after the EFORds for the delivery year are finalized, on November 30 in the year prior to the delivery year, but before the start of the delivery day. Effective with the 2025/2026 Delivery Year, replacement capacity transactions can be completed only after the accredited UCAP factors for the delivery year are finalized, but before the start of the delivery day. Early replacement transactions can be approved for defined physical replacements.

Changes in Generation Capacity[84]

As shown in Table 5-6, for the period from the introduction of the RPM capacity market design in the 2007/2008 Delivery Year through the 2024/2025 Delivery Year, internal installed capacity decreased by 7,487.1 MW after accounting for new capacity resources, reactivations, and uprates (57,618.3 MW) and capacity deactivations and derates (65,105.4 MW).[85]

For the 2025/2026 Delivery Year, new generation capacity is defined as capacity that cleared an RPM auction for the first time for the specified delivery year. Based on expected completion rates of cleared new generation capacity (6,089.7 MW) and pending deactivations (1,132.5 MW), PJM capacity is expected to increase by 4,957.2 MW through the 2026/2027 Delivery Year.

Table 5-6 Generation capacity changes: 2007/2008 through 2024/2025[86]

	ICAP (MW)								
	New	Reactivations	Uprates	Integration	Net Change in Capacity Imports	Net Change in Capacity Exports	Deactivations	Derates	Net Change
2007/2008	45.0	0.0	691.5	0.0	70.0	15.3	380.0	417.0	(5.8)
2008/2009	815.4	238.3	987.0	0.0	473.0	(9.9)	609.5	421.0	1,493.1
2009/2010	406.5	0.0	789.0	0.0	229.0	(1,402.2)	108.4	464.3	2,254.0
2010/2011	153.4	13.0	339.6	0.0	137.0	367.7	840.6	223.5	(788.8)
2011/2012	3,096.4	354.5	507.9	16,889.5	(1,183.3)	(1,690.3)	2,542.0	176.2	18,637.1
2012/2013	1,784.6	34.0	528.1	47.0	342.4	84.0	5,536.0	317.8	(3,201.7)
2013/2014	198.4	58.0	372.8	2,746.0	934.3	28.9	2,786.9	288.3	1,205.4
2014/2015	2,276.8	20.7	530.2	0.0	2,335.7	177.3	4,915.6	360.3	(289.8)
2015/2016	4,291.8	90.0	449.0	0.0	511.4	(117.8)	8,338.2	215.8	(3,094.0)
2016/2017	3,679.3	532.0	419.2	0.0	575.6	722.9	659.4	206.7	3,617.1
2017/2018	4,127.3	5.0	562.1	0.0	(1,025.1)	(695.1)	2,657.4	148.5	1,558.5
2018/2019	8,127.5	4.0	330.9	2,120.0	(3,217.0)	212.7	6,730.0	89.2	333.5
2019/2020	4,612.0	13.3	494.9	165.0	(1,196.6)	401.3	3,296.0	116.8	274.5
2020/2021	403.1	11.6	575.4	0.0	(37.9)	(111.6)	3,572.0	206.4	(2,714.6)
2021/2022	3,309.3	6.0	412.2	0.0	38.5	1,066.1	2,197.6	125.5	376.8
2022/2023	4,743.2	0.0	417.0	0.0	(469.3)	(868.0)	7,460.5	302.0	(2,203.6)
2023/2024	2,696.8	0.0	420.5	0.0	(47.9)	1,067.8	5,149.2	1,441.1	(4,588.7)
2024/2025	1,724.3	0.0	919.5	0.0	17.1	212.0	1,068.0	737.7	643.2
Total	46,491.1	1,380.4	9,746.8	21,967.5	(1,513.1)	(538.9)	58,847.3	6,258.1	13,506.2

84 For more details on future changes in generation capacity, see "2020 PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf> (September 15, 2020).
85 These results are for internal capacity only and do not include, for example, imports or exports or the impact of integrations of new areas.
86 The capacity changes in this report are calculated based on June 1 through May 31.

As shown in Table 5-7, total reserves on June 1, 2025, were 19,999.9 MW, which is 205.1 MW (UCAP) short of the required reserve level of 20,205.0 MW (UCAP). In the 2026/2027 BRA, total reserves were 21,353.2 MW, which is 208.7 MW (UCAP) short of the required reserve level of 21,561.9 MW (UCAP). In the 2027/2028 BRA, total reserves were 16,977.4 MW, which is 6,516.6 MW (UCAP) short of the required reserve level of 23,494.0 MW (UCAP). The level of committed demand resources was 5,530.6 MW in the 2026/2027 BRA and 7,298.6 in the 2027/2028 BRA, meaning the PJM markets will rely on demand resources as part of the required reserve margin, rather than as excess above the required reserve margin.

The fact that more than one quarter (25.6 percent of total reserves in the 2026/2027 BRA and 31.1 percent of total reserves in the 2027/2028 BRA) 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.

Table 5-7 RPM reserve margin: June 1, 2023, to June 1, 2027[87] [88]

	01-Jun-23	01-Jun-24	01-Jun-25	01-Jun-26	01-Jun-27	
Forecast peak load ICAP (MW)	149,382.2	151,631.1	154,534.1	156,760.6	164,579.0	A
FRR peak load ICAP (MW)	29,554.6	30,431.0	11,720.3	11,668.7	12,201.9	B
PRD ICAP (MW)	235.0	305.0	224.0	115.0	115.0	C
Installed reserve margin (IRM)	14.9%	17.7%	17.8%	18.6%	20.0%	D
Pool wide average EFORd	4.87%	5.10%				E
Pool wide accredited UCAP factor			79.63%	78.34%	77.17%	F
Forecast pool requirement (FPR)	1.093	1.117	0.938	0.929	0.926	G=(1+D)*(1-E) or G=(1+D)*F
RPM committed less deficiency UCAP (MW) (generation and DR)	136,401.8	138,318.6	133,544.1	136,511.6	134,478.1	H
RPM committed less deficiency ICAP (MW) (generation and DR)	143,384.6	145,751.9	167,705.8	174,255.3	174,262.1	J=H/(1-E) or J=H/F
RPM peak load ICAP (MW)	119,592.6	120,895.1	142,589.7	144,976.9	152,262.1	K=A-B-C
Reserve margin ICAP (MW)	23,792.0	24,856.9	25,116.0	29,278.4	22,000.0	L=J-K
Reserve margin (%)	19.9%	20.6%	17.6%	20.2%	14.4%	M=L/K
Reserve margin in excess of IRM ICAP (MW)	5,972.7	3,458.4	(264.9)	2,312.7	(8,452.4)	N=L-D*K
Reserve margin in excess of IRM (%)	5.0%	2.9%	(0.2%)	1.6%	(5.6%)	P=N/K
RPM peak load UCAP (MW)	113,768.4	114,729.4	113,544.2	113,574.9	117,500.7	Q=K*(1-E) or Q=K*F
RPM reliability requirement UCAP (MW)	130,714.7	135,039.8	133,749.2	134,698.0	140,994.7	R=K*G
Reserve margin UCAP (MW)	22,633.4	23,589.2	19,999.9	22,936.7	16,977.4	S=H-Q
Reserve cleared in excess of IRM UCAP (MW)	5,687.1	3,278.8	(205.1)	1,813.6	(6,516.6)	T=H-R
Projected replacement capacity UCAP (MW)	0.0	0.0	0.0	1,852.1	0.0	U
Projected reserve margin	19.9%	20.6%	17.6%	18.6%	14.4%	V=(J-U/(1-E))/K-1 or V=(J-U/F)/K-1

Sources of Funding[89]

Developers use a variety of sources to fund their projects, including Power Purchase Agreements (PPA), cost of service rates, and private funds (from internal sources or private lenders and investors). PPAs can be used for a variety of purposes and the use of a PPA does not imply a specific source of funding.

87 The calculated reserve margins in this table do not include EE on the supply side or the EE addback on the demand side. The EE excluded from the supply side for this calculation includes annual EE and summer EE. This is how PJM calculates the reserve margin. Effective with the 2026/2027 Deliver Year, EE resources no longer participate in the PJM capacity market. See 189 FERC ¶ 61,095 (November 5, 2024).

88 These reserve margin calculations do not consider Fixed Resource Requirement (FRR) load.

89 For more details on sources of funding for generation capacity, see "2020 PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf> (September 15, 2020).

New and reactivated generation capacity from the 2007/2008 Delivery Year through the 2024/2025 Delivery Year (Table 5-8) totaled 47,871.5 MW (83.1 percent of all additions), with 36,670.1 MW from market funding and 11,201.4 MW from nonmarket funding. Uprates to existing generation capacity from the 2007/2008 Delivery Year through the 2024/2025 Delivery Year totaled 9,746.8 MW (16.9 percent of all additions), with 6,983.7 MW from market funding and 2,763.1 MW from nonmarket funding. In summary, of the 57,618.3 MW of additional capacity from new, reactivated, and uprated generation that cleared in RPM auctions for the 2007/2008 through 2024/2025 Delivery Years, 43,653.8 MW (76.0 percent) were based on market funding.

Table 5-8 Sources of funding: 2007/2008 through 2024/2025 Delivery Years

	ICAP MW					
2007/2008 DY through 2024/2025 DY	New and Reactivated	Percent of Grand Total	Uprate	Percent of Grand Total	Total	Percent of Grand Total
Market	36,670.1	63.6%	6,983.7	12.1%	43,653.8	75.8%
Nonmarket	11,201.4	19.4%	2,763.1	4.8%	13,964.5	24.2%
Total	47,871.5	83.1%	9,746.8	16.9%	57,618.3	100.0%

Of the 21,915.0 MW of the additional generation capacity (new resources, reactivated resources, and uprates) that cleared in RPM auctions for the 2025/2026 through the 2027/2028 Delivery Years (Table 5-9), 7,587.0 MW are not yet in service, with 7,380.9 MW of those having market funding. Applying the historical completion rates, 63.9 percent of all the projects in development are expected to go into service, 4,710.1 MW of the 7,380.9 MW in development market funded projects, and 134.3 MW of the 206.1 MW in development non market funded projects.[90]

Of the 14,328.0 MW of the additional generation capacity that cleared in RPM auctions for the 2025/2026 through the 2027/2028 Delivery Years and are already in service, 10,510.8 MW (73.4 percent) are based on market funding and 3,817.2 MW (26.6 percent) are based on nonmarket funding.

In summary, 17,891.7 MW (81.6 percent) of the additional generation capacity (7,380.9 MW not yet in service and 10,510.8 MW in service) that cleared in RPM auctions for the 2025/2026 through the 2027/2028 Delivery Years are based on market funding. Capacity additions based on nonmarket funding are 4,023.3 MW (18.4 percent) of generation that cleared the RPM auctions for the 2025/2026 and 2027/2028 Delivery Years.

90 See the *2025 Annual State of the Market Report for PJM*, Volume 2, Section 12: Generation and Transmission Planning.

Table 5-9 Sources of funding: 2025/2026 through 2027/2028 Delivery Years

	ICAP MW								
2025/2026 DY through 2027/2028 DY	Not Yet in Service	Percent	Percent of Grand Total	In Service	Percent	Percent of Grand Total	Total	Percent of Grand Total
Market	7,380.9	97.3%	33.7%	10,510.8	73.4%	48.0%	17,891.7	81.6%
Nonmarket	206.1	2.7%	0.9%	3,817.2	26.6%	17.4%	4,023.3	18.4%
Total	7,587.0	100.0%	34.6%	14,328.0	100.0%	65.4%	21,915.0	100.0%

Demand

The MMU analyzed market sectors in the PJM Capacity Market to determine how they met their load obligations. The PJM Capacity Market was divided into the following sectors:

- **PJM EDC.** EDCs with a franchise service territory within the PJM footprint. This sector includes traditional utilities, electric cooperatives, municipalities and power agencies.
- **PJM EDC Generating Affiliate.** Affiliate companies of PJM EDCs that own generating resources.
- **PJM EDC Marketing Affiliate.** Affiliate companies of PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-PJM EDC.** EDCs with franchise service territories outside the PJM footprint.
- **Non-PJM EDC Generating Affiliate.** Affiliate companies of non-PJM EDCs that own generating resources.
- **Non-PJM EDC Marketing Affiliate.** Affiliate companies of non-PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-EDC Generating Affiliate.** Affiliate companies of non-EDCs that own generating resources.

- **Non-EDC Marketing Affiliate.** Affiliate companies of non-EDCs that sell power and have load obligations in PJM, but do not own generating resources.

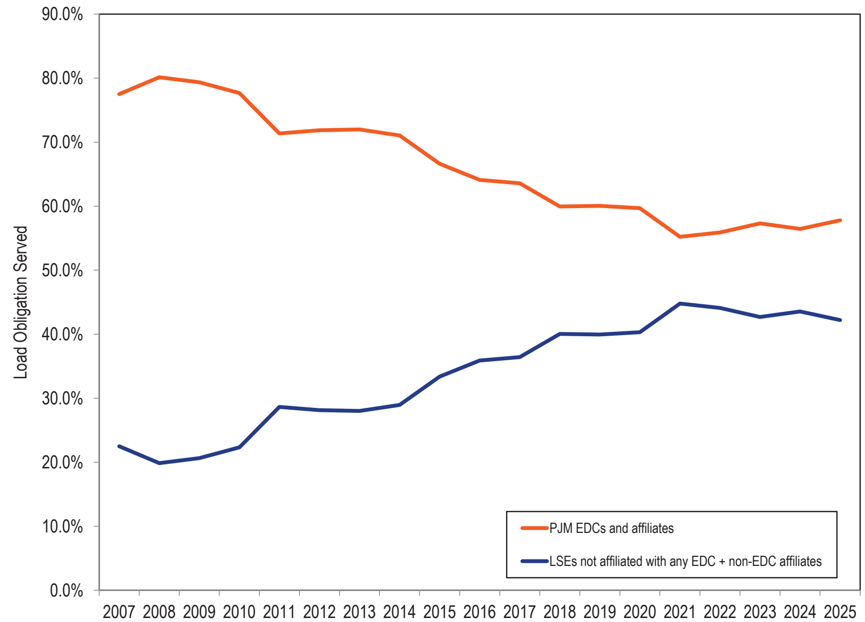
On June 1, 2025, PJM EDCs and their affiliates maintained a majority market share of load obligations under RPM, together totaling 57.8 percent (Table 5-10), up from 56.4 percent on June 1, 2024. The combined market share of LSEs not affiliated with any EDC and of non-PJM EDC affiliates was 42.2 percent, down from 43.6 percent on June 1, 2024. The share of capacity market load obligation fulfilled by PJM EDCs and their affiliates, and LSEs not affiliated with any EDC and non-PJM EDC affiliates from June 1, 2007, to June 1, 2025, is shown in Figure 5-3. PJM EDCs' and their affiliates' share of load obligation has decreased from 77.5 percent on June 1, 2007, to 57.8 percent on June 1, 2025. The share of load obligation held by LSEs not affiliated with any EDC and non-PJM EDC affiliates increased from 22.5 percent on June 1, 2007, to 42.2 percent on June 1, 2025.[91]

Table 5-10 Capacity market load obligation served: June 1, 2024 and June 1, 2025

	01-Jun-24		01-Jun-25		Change	
	Obligation (MW)	Percent of total obligation	Obligation (MW)	Percent of total obligation	Obligation (MW)	Percent of total obligation
PJM EDCs and Affiliates	106,462.1	56.4%	86,471.6	57.8%	(19,990.5)	1.4%
LSEs not affiliated with any EDC + non EDC Affiliates	82,180.1	43.6%	63,166.5	42.2%	(19,013.6)	(1.4%)
Total	188,642.2	100.0%	149,638.1	100.0%	(39,004.1)	0.0%

91 Prior to the 2012/2013 Delivery Year, obligation was defined as cleared and make whole MW in the Base Residual Auction and the Second Incremental Auction plus ILR forecast obligations. Effective with the 2012/2013 Delivery Year, obligation is defined as the sum of the unforced capacity obligations satisfied through all RPM auctions for the delivery year.

Figure 5-3 Capacity market load obligation served: June 1, 2007 through June 1, 2025



Capacity Transfer Rights (CTRs)

Capacity Transfer Rights (CTRs) are used to return capacity market congestion revenues to load. Load pays congestion. Capacity market congestion revenues are the difference between the total dollars paid by load for capacity and the total dollars received by capacity market sellers. The MW of CTRs available for allocation to LSEs in an LDA are equal to the Unforced Capacity imported into the LDA, less any MW of CETL paid for directly by market participants in the form of Qualifying Transmission Upgrades (QTUs) cleared in an RPM Auction, and Incremental Capacity Transfer Rights (ICTRs). There are two types of ICTRs, those allocated to a New Service Customer obligated to fund a transmission facility or upgrade and those associated with Incremental Rights-Eligible Required Transmission Enhancements.

The total required capacity in an LDA is provided by a mix of internal capacity and imported capacity. The imported capacity equals the total required capacity minus the internal capacity. The value of CTRs is based on the fact that load in an LDA pays the clearing price for all cleared capacity but that generators who provide imported capacity are paid a lower price based on the LDA in which they are located. The value of CTRs equals the imported MW times the price difference. This excess is paid by load and is returned to load using CTRs. CTRs are intended to permit customers to receive the benefit of importing cheaper capacity using transmission capability.

But PJM does not use the actual MW cleared in the BRA and three incremental auctions, the actual internal MW and the actual imported MW, when defining what customers pay and when defining the value of CTRs. Under the current rules, PJM defines the total MW needed for reliability in an LDA when clearing the BRA based on forecast demand at the time of the BRA. But PJM actually charges customers for the total MW needed for reliability based on forecast demand three years later, prior to the actual delivery year, and applies a zonal allocation. PJM also defines the internal capacity as the internal capacity after the final incremental auction conducted three years after the BRA, when auctions follow the traditional schedule. The difference between the updated MW needed for reliability and the updated internal capacity is the updated imported MW, adjusted for the final zonal allocation. In cases where the updated imported MW are smaller than the imported MW from the actual auction clearing, the total value of CTRs is lower that it would be if the actual auction clearing MW were used.

The actual load charges are allocated to each zone based on the ratio of the zonal forecast peak load to the RTO forecast peak load used for the third incremental auction conducted three months prior to the delivery year.

The CTR issue implies a broader issue with capacity market clearing and settlements. The capacity market is cleared based on a three year ahead forecast of load and offers of capacity. Payments to capacity resources in the delivery year are based on the capacity market clearing prices and quantities. But payments by customers in the delivery year are not based on market clearing prices and quantities. Payments by customers in each zone are based on the ratio of zonal forecast peak load to the RTO forecast peak load used for the Third Incremental Auction, run three months prior to the delivery year when auctions follow the traditional schedule.[92] The allocation sometimes creates significant differences between the capacity cleared to meet the reliability requirement and the capacity obligation allocated to the customers in a zone. For example, ComEd Zone, which is identical to ComEd LDA, cleared 27,932.1 MW including 5,574.0 MW of imports in the 2021/2022 RPM BRA. The ComEd Zone's capacity obligation, immediately after the clearing of the Base Residual Auction was 24,983.0 MW. The final ComEd Zone's capacity obligation for the 2021/2022 Delivery Year after the Third Incremental Auction was 22,721.2 MW.

As with CTRs, the underlying reasons for not using the market clearing results are not clear. Although not stated explicitly, the goal appears to be to reflect the fact that actual loads change between the auction and the delivery year. But the simple reallocation of capacity obligations based on changes in the load forecast does not reflect the BRA market results. 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.

For LDAs in which the RPM auctions for a delivery year resulted in a positive average weighted Locational Price Adder, an LSE with CTRs corresponding to the LDA is entitled to a payment or charge equal to the Locational Price Adder multiplied by the MW of the LSEs' CTRs. The definition of the MW does not reflect auction clearing MW.

In the 2025/2026 RPM Third Incremental Auction, BGE had 5,024.2 MW of CTRs with a total value of $360.6 million and DOM had 1,752.6 MW of CTRs with a total value of $112.8 million. BGE had 65.7 MW of customer funded ICTRs with a total value of $4.7 million. BGE had 306.0 MW of ICTRs due to Incremental Rights Eligible Required Transmission Enhancements with a value of $22.0 million.

92 See "PJM Manual 18: PJM Capacity Market," § 7.2.3 Final Zonal Unforced Capacity Obligations, Rev. 62 (Dec. 17, 2025).

The 2026/2027 RPM Base Residual Auction cleared at $329.17 per MW-day with no price separation and therefore the value of CTRs is $0.

The 2027/2028 RPM Base Residual Auction cleared at $333.44 per MW-day with no price separation and therefore the value of CTRs is $0.

Demand Curve

A central feature of PJM's Reliability Pricing Model (RPM) design is that the demand curve, or Variable Resource Requirement (VRR) curve, has a downward sloping segment. In the RPM market design, the supply of three year forward capacity is cleared against this VRR curve. A VRR curve is defined for each Locational Deliverability Area (LDA). This shape replaced the vertical demand curve at the reliability requirement. The downward sloping segment begins at the MW level that is approximately 1.0 percent less than the reliability requirement.[93] Figure 5-4 shows the shape of the VRR curve for the 2026/2027 RPM Base Residual Auction.

The initial VRR curve, introduced in 2007, had a maximum price equal to 1.5 times the Net Cost of New Entry (Net CONE), determined annually based on fixed cost of new generating capacity, which is the Gross Cost of New Entry (Gross CONE), net of the three year average historical energy and ancillary service revenues. That VRR curve was structured to yield auction clearing prices equal to 1.5 times Net CONE when the amount of capacity cleared was less than 99 percent of the target reserve margin and below 1.5 times Net CONE when the amount of capacity cleared was greater than 99 percent of the target reserve margin.

Effective for the 2018/2019 through 2021/2022 Delivery Years, a revised VRR curve was implemented after PJM conducted a triennial review.[94] [95] PJM defines the reliability requirement as the capacity needed to satisfy the one event in ten years loss of load expectation (LOLE) for the RTO and capacity needed to satisfy the one event in 25 years loss of load expectation for the each LDA. PJM increased the maximum price on the VRR curve to be the greater of Gross CONE or 1.5 times Net CONE for all unforced capacity MW between 0 and 99.8 percent of the reliability requirement. The first downward sloping segment was from 99.8 percent and 102.5 percent of the reliability requirement. The second downward sloping segment was from 102.5 percent and 107.6 percent of the reliability requirement.

Effective for the 2022/2023 through 2025/2026 Delivery Years, another revised VRR curve was implemented after PJM conducted a quadrennial review.[96] The maximum price on the VRR curve was the greater of Gross CONE or 1.5 times Net CONE for all unforced capacity MW between 0 and 98.9 percent of the reliability requirement. The first downward sloping segment was from 98.9 percent and 101.6 percent of the reliability requirement. The second downward sloping segment was from 101.6 percent and 106.8 percent of the reliability requirement (Figure 5-4).

Effective for the 2026/2027 through 2029/2030 Delivery Years, another revised VRR curve was implemented after PJM conducted a quadrennial review.[97] PJM increased the maximum price on the VRR curve to the greater of Gross CONE or 1.75 times Net CONE for all unforced capacity MW between 0 and 99.0 percent of the reliability requirement. The first downward sloping segment is from 99.0 percent and 101.5 percent of the reliability requirement. The second downward sloping segment is from 101.5 percent and 104.5 percent of the reliability requirement.

The VRR curve was then changed significantly based on PJM's filing to establish the maximum price point on the VRR curve equal to "approximately" $325/MW-day in UCAP with a new MW point that is inconsistent with the tariff definition, a new minimum price point on the VRR curve of "approximately" $175/MW-day in UCAP for an unlimited number of MW that is inconsistent with the tariff, and a VRR curve shape not consistent with the tariff definition, for all Reliability Pricing Model ("RPM") Auctions, including Base Residual Auctions and Incremental Auctions, for the 2026/2027 and 2027/2028 Delivery Years.[98] The VRR curve has always had a maximum price. The VRR

93 The formula for the MW level where the VRR curve begins the downward slope is given by *(Reliability Requirement) x [1 – 1.2% / (Installed Reserve Margin)]*.

94 "Third Triennial Review of PJM's Variable Resource Requirement Curve," The Brattle Group, May 15, 2014, <http://www.pjm.com//media/library/reports-notices/reliability-pricing-model/20140515-brattle-2014-pjm-vrr-curvereport.ashx?la=en>.

95 153 FERC ¶ 61,035 (October 15, 2015).

96 167 FERC ¶ 61,029 (April 15, 2019).

97 182 FERC ¶ 61,073 (Feb. 14, 2023).

98 PJM Filing. Proposal for Revised Price Cap and Price Floor for the 2026/2027 and 2027/2028 Delivery Years, and Request for a Waiver of the 60-Days' Notice Requirement to Allow for a March 31, 2025 Effective Date, Docket No. ER25-1357 (Feb. 20, 2025). The modified

curve has always had a minimum price equal to zero. The proposal would set the maximum price level at somewhat higher than 1.5 times Net CONE. The MMU position is that the maximum price should be equal to the lesser of 1.5 times Net CONE or Gross CONE.[99] The MMU opposed the imposition of a completely unsupported floor price that is inconsistent with the longstanding VRR curve design.

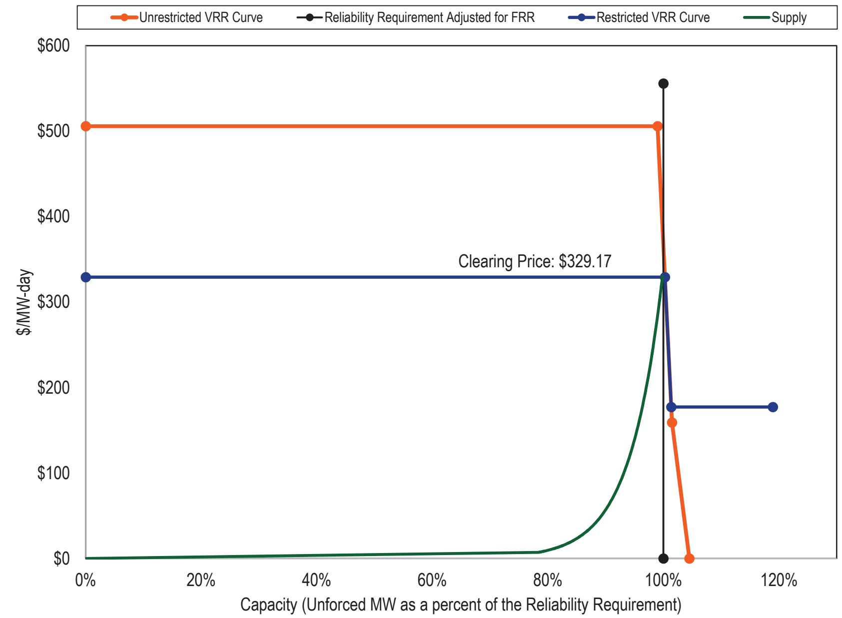
The initial VRR curve, introduced in 2007, had a maximum price equal to 1.5 times the Net Cost of New Entry (Net CONE). The use of Net CONE was based on the logic of the capacity market, to ensure that between the energy and capacity markets the cost of entry was covered. Net CONE was the missing money from the energy and ancillary services markets that needed to be recoverable in the capacity market. The inclusion of the net energy and ancillary services markets revenue in the calculation of Net CONE was the equilibrating factor between the capacity market and energy market. The use of Gross CONE is inconsistent with that basic capacity market logic as is the use of 1.75 times Net CONE which is frequently greater than Gross CONE. Gross CONE was introduced as the maximum price based on PJM's unsupported assertions that Net CONE would somehow be too low. The maximum point on the VRR curve for the 2025/2026 BRA was the higher of Gross CONE or 1.5 times Net CONE, and Gross CONE was actually used. However, if the logic of the markets implies a low Net CONE, that is the right answer. There is nothing inherently wrong with a low Net CONE that requires abandoning the basic capacity market logic. Gross CONE was an intervention designed to increase capacity market prices based on a judgment about what prices should be despite the fact that the basic economic logic did not support that increase. If there is an issue with the calculation of Net CONE, it should be addressed directly rather than by ignoring its central role in the design of the capacity market. As Gross CONE numbers are reasonably well defined, much more focus on getting the net revenues used in the forward auctions is required in order to ensure that market participants have confidence in the Net CONE values used in the auctions.

maximum price and the addition of a price floor were based on the Agreement between Governor Josh Shapiro of the Commonwealth of Pennsylvania and PJM.

99 See Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, (April 16, 2025). <https://www.monitoringanalytics.com/filings/2025/IMM_Answer_to_Answer_Docket_No_ER25-1357_20250416.pdf>.

Figure 5-4 shows the RTO VRR curve and RTO reliability requirement for the 2026/2027 RPM BRA.

Figure 5-4 Shape of the VRR curve relative to the reliability requirement: 2026/2027 Delivery Year



Market Concentration

Auction Market Structure

As shown in Table 5-11, in the 2026/2027 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.[100] 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,

100 The market definition used for the TPS test includes all offers with costs less than or equal to 1.50 times the clearing price. See *MMU Technical Reference for PJM Markets*, at "Three Pivotal Supplier Test" for additional discussion.

and the submitted sell offer, absent mitigation, increased the market clearing price.[101] [102] [103]

In applying the market structure test, the relevant supply for the RTO market includes all supply offered at less than or equal to 150 percent of the RTO cost-based clearing price. The relevant supply for the constrained LDA markets includes the incremental supply inside the constrained LDAs which was offered at a price higher than the unconstrained clearing price for the parent LDA market and less than or equal to 150 percent of the cost-based clearing price for the constrained LDA. The relevant demand consists of the MW needed inside the LDA to relieve the constraint.

Table 5-11 presents the results of the TPS test. A generation owner or owners are pivotal if the capacity of the owners' generation facilities is needed to meet the demand for capacity. The results of the TPS are measured by the residual supply index (RSI_x). The RSI_x is a general measure that can be used with any number of pivotal suppliers. The subscript denotes the number of pivotal suppliers included in the test. If the RSI_x is less than or equal to 1.0, the supply owned by the specific generation owner, or owners, is needed to meet market demand and the generation owners are pivotal suppliers with a significant ability to influence market prices. If the RSI_x is greater than 1.0, the supply of the specific generation owner or owners is not needed to meet market demand and those generation owners have a reduced ability to unilaterally influence market price.

101 See OATT Attachment DD § 6.5.
102 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).
103 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).

Table 5-11 RSI results: 2023/2024 through 2027/2028 RPM Auctions[104]

RPM Markets	RSI1, 1.05	RSI3	Total Participants	Failed RSI3 Participants
2023/2024 Base Residual Auction				
RTO	0.78	0.68	134	134
MAAC	0.78	0.40	11	11
DPL South	0.00	0.00	1	1
BGE	0.00	0.00	1	1
2023/2024 Third Incremental Auction				
RTO	0.77	0.76	51	15
MAAC	0.41	0.76	17	9
EMAAC	0.45	0.18	10	10
BGE	0.00	0.00	1	1
2024/2025 Base Residual Auction				
RTO	0.77	0.64	133	133
MAAC	0.59	0.11	9	9
EMAAC	0.48	0.00	2	2
DPL South	0.00	0.00	1	1
BGE	0.00	0.00	1	1
DEOK	0.00	0.00	1	1
2024/2025 Third Incremental Auction				
RTO	0.88	0.59	64	64
MAAC	0.60	0.17	10	10
EMAAC	0.00	0.00	1	1
BGE	0.00	0.00	1	1
2025/2026 Base Residual Auction				
RTO	0.82	0.62	128	128
BGE	0.00	0.00	0	0
Dominion	0.00	0.00	0	0
2025/2026 Third Incremental Auction				
RTO	0.60	0.31	75	75
BGE	0.00	0.00	0	0
2026/2027 Base Residual Auction				
RTO	0.82	0.64	153	153
2026/2027 Third Incremental Auction				
RTO	0.82	0.67	120	120
2027/2028 Base Residual Auction				
RTO	0.82	0.63	155	155

104 The RSI shown is the lowest RSI in the market.

Locational Deliverability Areas (LDAs)

Under the PJM Tariff, PJM determines, in advance of each BRA, whether defined Locational Deliverability Areas (LDAs) will be modeled in the auction. Effective with the 2012/2013 Delivery Year, an LDA is modeled as a potentially constrained LDA for a delivery year if the Capacity Emergency Transfer Limit (CETL) is less than 1.15 times the Capacity Emergency Transfer Objective (CETO), such LDA had a locational price adder in one or more of the three immediately preceding BRAs, or such LDA is determined by PJM in a preliminary analysis to be likely to have a locational price adder based on historic offer price levels. The rules also provide that starting with the 2012/2013 Delivery Year, EMAAC, SWMAAC, and MAAC LDAs are modeled as potentially constrained LDAs regardless of the results of the above three tests.[105] In addition, PJM may establish a constrained LDA even if it does not qualify under the above tests if PJM finds that "such is required to achieve an acceptable level of reliability."[106] A reliability requirement and a Variable Resource Requirement (VRR) curve are established for each modeled LDA. Effective for the 2014/2015 through 2016/2017 Delivery Years, a Minimum Annual and a Minimum Extended Summer Resource Requirement were established for each modeled LDA. Effective for the 2017/2018 Delivery Year, Sub-Annual and Limited Resource Constraints, replacing the Minimum Annual and a Minimum Extended Summer Resource Requirements, were established for each modeled LDA.[107] [108] Effective for the 2018/2019 and the 2019/2020 Delivery Years, a Base Capacity Demand Resource Constraint and a Base Capacity Resource Constraint, replacing the Sub-Annual and Limited Resource Constraints, were established for each modeled LDA.

Imports and Exports

Units external to the metered boundaries of PJM can qualify as PJM capacity resources if they meet the requirements to be capacity resources. Generators on the PJM system that do not have a commitment to serve PJM loads in the given delivery year as a result of RPM auctions, FRR capacity plans, locational UCAP transactions, and/or are not designated as a replacement resource, are eligible to export their capacity from PJM.[109]

The market rules in other balancing authorities should also not create inappropriate barriers to the import or export of capacity. The PJM market rules should ensure that the definition of capacity is enforced including physical deliverability, recallability and the obligation to make competitive offers into the PJM Day-Ahead Energy Market equal to ICAP MW. Physical deliverability can only be assured by requiring that all imports are deliverable to PJM load to ensure that they are full substitutes for internal capacity resources. Selling capacity into the PJM Capacity Market but making energy offers daily of $999 per MWh would not fulfill the requirements of a capacity resource to make a competitive offer, but would constitute economic withholding. This is one of the reasons that the rules governing the obligation to make a competitive offer in the day-ahead energy market should be clarified for both internal and external resources. The PJM market rules should also not create inappropriate barriers to either the import or export of capacity.

The calculation of CETL should only include capacity imports into PJM where the capacity has an explicit must offer requirement in the PJM Capacity Market. These could include pseudo tied units or resources with a grandfathered obligation. The external capacity that does not have a must offer requirement in the PJM capacity market is not obligated to serve PJM load under all conditions and therefore should not be assumed to be a source of capacity. This capacity should not be included in PJM's power flow calculations used to deriver CETL values between PJM's LDAs. PJM has modified its CETL calculations to exclude such capacity.

The establishment of a pseudo tie is one requirement for an external resource to be eligible to participate in the PJM Capacity Market. Pseudo tied external resources, regardless of their location, are treated as only meeting the reliability requirements of the rest of RTO and not the reliability requirements of any specific locational deliverability area (LDA). All imports offered in the auction from areas external to PJM are modeled as supply in the rest of RTO and not in any specific zonal or subzonal LDA. The fact that pseudo tied external

105 Prior to the 2012/2013 Delivery Year, an LDA with a CETL less than 1.05 times CETO was modeled as a constrained LDA in RPM. No additional criteria were used in determining modeled LDAs.
106 OATT Attachment DD § 5.10 (a) (ii).
107 146 FERC ¶ 61,052 (2014).
108 Locational Deliverability Areas are shown in maps in the *2021 Annual State of the Market Report for PJM*, Volume 2, Section 5: "Capacity Market" at "Locational Deliverability Areas (LDAs)".
109 OATT Attachment DD § 5.6.6(b).

resources cannot be identified as equivalent to resources internal to specific LDAs illustrates a fundamental issue with capacity imports. Capacity imports are not equivalent to, nor substitutes for, internal resources. All internal resources are internal to a specific LDA.[110]

Effective May 9, 2017, significantly improved pseudo tie requirements for external generation capacity resources were implemented.[111] The rule changes include: defining coordination with other Balancing Authorities when conducting pseudo tie studies; establishing an electrical distance requirement; establishing a market to market flowgate test to establish limits on the number of coordinated flowgates PJM must add in order to accommodate a new pseudo tie; a model consistency requirement; the requirement for the capacity market seller to provide written acknowledgement from the external Balancing Authority Areas that such pseudo tie does not require tagging and that firm allocations associated with any coordinated flowgates applicable to the external Generation Capacity Resource under any agreed congestion management process then in effect between PJM and such Balancing Authority Area will be allocated to PJM; the requirement for the capacity market seller to obtain long-term firm point to point transmission service for transmission outside PJM with rollover rights and to obtain network external designated transmission service for transmission within PJM; establishing an operationally deliverable standard; and modifying the nonperformance penalty definition for external generation capacity resources to assess performance at subregional transmission organization granularity.

Generation external to the PJM region is eligible to be offered into an RPM auction if it meets specific requirements.[112] [113] [114] Firm transmission service must be acquired from all external transmission providers between the unit and border of PJM and generation deliverability into PJM must be demonstrated prior to the start of the delivery year. In order to demonstrate generation deliverability into PJM, external generators must obtain firm point to point transmission service on the PJM OASIS from the PJM border into the PJM transmission system or by obtaining network external designated transmission service. In the event that transmission upgrades are required to establish deliverability, those upgrades must be completed by the start of the delivery year. The following are also required: the external generating unit must be in the resource portfolio of a PJM member; 12 months of NERC/GADs unit performance data must be provided to establish an EFORd; the net capability of each unit must be verified through winter and summer testing; and a letter of non-recallability must be provided to assure PJM that the energy and capacity from the unit is not recallable to any other balancing authority.

All external generation resources that have an RPM commitment or FRR capacity plan commitment or that are designated as replacement capacity must be offered in the PJM day-ahead energy market.[115]

Planned External Generation Capacity Resources are eligible to be offered into an RPM Auction if they meet specific requirements.[116] [117] Planned External Generation Capacity Resources are proposed Generation Capacity Resources, or a proposed increase in the capability of an Existing Generation Capacity Resource, that is located outside the PJM region; participates in the generation interconnection process of a balancing authority external to PJM; is scheduled to be physically and electrically interconnected to the transmission facilities of such balancing authority on or before the first day of the delivery year for which the resource is to be committed to satisfy the reliability requirements of the PJM region; and is in full commercial operation prior to the first day of the delivery year.[118] An External Generation Capacity Resource becomes an Existing Generation Capacity Resource as of the earlier of the date that interconnection service commences or the resource has cleared an RPM Auction for a prior delivery year.[119]

110 External resources are not assigned to any of the five global LDAs or 22 zonal and subzonal LDAs. PJM's current practice is to model external resources in the rest of RTO. The practice is not currently documented by PJM. It was previously documented in "PJM Manual 18: PJM Capacity Market," § 2.3.4 Capacity Import Limits, Rev. 39 (Dec. 21, 2017).
111 161 FERC ¶ 61,197 (2017).
112 See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 9 & 10.
113 "PJM Manual 18: PJM Capacity Market," § 4.2.2 Existing Generation Capacity Resources – External, Rev. 62 (Dec. 17, 2025).
114 "PJM Manual 18: PJM Capacity Market," § 4.6.4 Importing an External Generation Resource, Rev. 62 (Dec. 17, 2025).
115 OATT Schedule 1 § 1.10.1A.
116 See "Reliability Assurance Agreement among Load Serving Entities in the PJM Region," Section 1.69A.
117 "PJM Manual 18: PJM Capacity Market," § 4.2.4 Planned Generation Capacity Resources – External, Rev. 62 (Dec. 17, 2025).
118 Prior to January 31, 2011, capacity modifications to existing generation capacity resources were not considered planned generation capacity resources. See 134 FERC ¶ 61,065 (2011).
119 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation. See 134 FERC ¶ 61,065 (2011).

As shown in Table 5-12, of the 1,144.8 MW of imports offered in the 2027/2028 RPM Base Residual Auction, 1,005.9 MW cleared. Of the cleared imports, 695.6 MW (69.2 percent) were from MISO.

Table 5-12 RPM imports: 2007/2008 through 2027/2028 RPM Base Residual Auctions

	UCAP (MW)					
	MISO		Non-MISO		Total Imports	
Base Residual Auction	Offered	Cleared	Offered	Cleared	Offered	Cleared
2007/2008	1,073.0	1,072.9	547.9	547.9	1,620.9	1,620.8
2008/2009	1,149.4	1,109.0	517.6	516.8	1,667.0	1,625.8
2009/2010	1,189.2	1,151.0	518.8	518.1	1,708.0	1,669.1
2010/2011	1,194.2	1,186.6	539.8	539.5	1,734.0	1,726.1
2011/2012	1,862.7	1,198.6	3,560.0	3,557.5	5,422.7	4,756.1
2012/2013	1,415.9	1,298.8	1,036.7	1,036.7	2,452.6	2,335.5
2013/2014	1,895.1	1,895.1	1,358.9	1,358.9	3,254.0	3,254.0
2014/2015	1,067.7	1,067.7	1,948.8	1,948.8	3,016.5	3,016.5
2015/2016	1,538.7	1,538.7	2,396.6	2,396.6	3,935.3	3,935.3
2016/2017	4,723.1	4,723.1	2,770.6	2,759.6	7,493.7	7,482.7
2017/2018	2,624.3	2,624.3	2,320.4	1,901.2	4,944.7	4,525.5
2018/2019	2,879.1	2,509.1	2,256.7	2,178.8	5,135.8	4,687.9
2019/2020	2,067.3	1,828.6	2,276.1	2,047.3	4,343.4	3,875.9
2020/2021	2,511.8	1,671.2	2,450.0	2,326.0	4,961.8	3,997.2
2021/2022	2,308.4	1,909.9	2,162.0	2,141.9	4,470.4	4,051.8
2022/2023	954.9	954.9	603.1	603.1	1,558.0	1,558.0
2023/2024	967.9	836.5	560.1	560.1	1,528.0	1,396.6
2024/2025	949.9	820.4	577.2	577.2	1,527.1	1,397.6
2025/2026	700.5	700.5	568.0	568.0	1,268.5	1,268.5
2026/2027	697.4	697.4	584.3	584.3	1,281.7	1,281.7
2027/2028	695.6	695.6	449.2	310.3	1,144.8	1,005.9

One of the reasons that a Generation Capacity Resource may qualify for an exception to the RPM must offer requirement is by demonstration that it has a financially and physically firm commitment to an external sale of its capacity.[120] Exporting a Generation Capacity Resource requires a financially and physically firm commitment to load located outside the PJM Region. The PJM Tariff states "In order to establish that a resource has a financially and physically firm commitment to an external sale of its capacity, the Capacity Market Seller must demonstrate that it has entered into a unit-specific bilateral transaction for service to load located outside the PJM Region, by a demonstration that such resource is identified on a unit-specific basis as a network resource under the transmission tariff for the control area applicable to such external load, or by an equivalent demonstration of a financially and physically firm commitment to an external sale. The Capacity Market Seller additionally shall identify the megawatt amount, export zone, and time period (in days) of the export."[121]

The MMU recommends that the PJM Tariff be modified to explicitly state that in order to qualify, a Capacity Market Seller requesting a must offer exception based on a financially and physically firm commitment to an external sale of its capacity must provide a confirmed firm transmission reservation, covering the entire path from source to sink, for the full requested ICAP MW of the external sale that covers the entire delivery year, by the tariff defined deadline. The MMU recommends that this language apply to all external sales of Generation Capacity Resources, including those where an external balancing authority does not require this level of transmission service in order to consider a PJM resource as a network resource.

Demand Resources

The level of DR products that buy out of their positions after the BRA means that the treatment of DR has a negative impact on generation investment incentives and that the rules governing the requirement to be a physical resource should be more clearly stated and enforced.[122] If DR displaces new generation resources in BRAs, but then buys out of the position prior to the delivery year, this means potentially replacing new entry generation resources at the high end of the supply curve with other existing but uncleared capacity resources available in Incremental Auctions at reduced offer prices. This suppresses the price of capacity in the BRA compared to the competitive result because it permits the shifting of demand from the BRA to the Incremental Auctions, which is inconsistent with the must offer, must buy rules, and the

120 OATT Attachment DD § 6.6(g).

121 Ibid.

122 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).

requirement to be an actual, physical resource, governing the BRA. PJM's sell back of capacity in Incremental Auctions exacerbates the incentive for DR to buy out of its BRA positions in IAs.

Effective with the 2020/2021 Delivery Year, DR includes annual and summer products. Annual Demand Resources are required to be available on any day during the Delivery Year for an unlimited number of interruptions between the hours of 10:00 a.m. and 10:00 p.m. EPT for the months of June through October and the following May and between the hours of 6:00 a.m. and 9:00 p.m. EPT for the months of November through April unless there is a PJM approved maintenance outage during the October through April period.

Summer-Period Demand Resources are required to be available on any day from June through October and the following May of the delivery year for an unlimited number of interruptions between the hours of 10:00 a.m. to 10:00 p.m. EPT.

As shown in Table 5-13, and Table 5-14, committed DR was 5,782.9 MW for June 1, 2025, as a result of cleared capacity for demand resources in RPM auctions for the 2025/2026 Delivery Year (6,265.9 MW) less replacement capacity (483.0 MW).

Table 5-13 RPM load management statistics by LDA: June 1, 2023 to June 1, 2027[123] [124] [125] [126]

		UCAP (MW)																
		RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ATSI Cleveland	ComEd	BGE	PPL	DAY	DEOK	Dominion	JCPL
01-Jun-23	DR cleared	8,174.1	2,411.4	975.9	343.6	52.2	272.7	126.1	175.2	916.2	189.4	1,253.2	168.4	583.4	209.3	175.4		
	EE cleared	5,896.4	2,438.6	1,341.4	569.5	59.3	443.4	210.4	298.6	451.8	46.3	961.2	270.9	306.1	102.4	164.3		
	DR net replacements	(466.2)	(229.5)	(3.8)	(4.9)	22.8	3.4	2.6	(25.0)	47.2	(63.4)	160.7	20.1	(123.3)	(24.0)	25.0		
	EE net replacements	(5.3)	(2.2)	(1.0)	7.6	9.0	11.6	13.7	7.6	(15.3)	(0.5)	(20.9)	0.0	(6.2)	(7.9)	0.7		
	RPM load management	13,599.0	4,618.3	2,312.5	915.8	143.3	731.1	352.8	456.4	1,399.9	171.8	2,354.2	459.4	760.0	279.8	365.4		
01-Jun-24	DR cleared	8,064.7	2,497.6	1,004.0	358.5	46.0	285.7	98.2	160.4	682.6	141.6	1,554.0	198.1	603.4	192.9	221.9		
	EE cleared	7,716.0	3,543.5	2,064.9	787.4	99.9	802.9	392.0	398.9	587.6	54.9	1,063.4	388.5	391.4	128.3	188.1		
	DR net replacements	(364.8)	(197.4)	9.1	43.0	35.2	(7.3)	(14.9)	19.3	50.9	(58.3)	(56.0)	23.7	(138.9)	(6.2)	(5.4)		
	EE net replacements	(48.0)	(43.6)	(15.4)	21.3	14.1	(6.5)	(0.1)	9.1	(30.6)	0.0	1.2	12.2	(38.4)	(5.6)	(3.7)		
	RPM load management	15,367.9	5,800.1	3,062.6	1,210.2	195.2	1,074.8	475.2	587.7	1,290.5	138.2	2,562.6	622.5	817.5	309.4	400.9		
01-Jun-25	DR cleared	6,265.9	1,860.8	784.9	304.0	65.0	228.9	65.8	135.7	712.7	97.3	1,090.5	168.3	424.9	141.0	159.6	673.5	
	EE cleared	1,493.2	674.7	433.5	154.7	24.0	184.0	100.0	80.0	69.1	6.6	337.6	74.7	45.7	18.5	24.9	154.2	
	DR net replacements	(483.0)	(140.4)	(60.2)	(11.6)	(30.3)	(10.4)	(14.3)	(15.1)	(39.8)	(4.8)	(29.0)	3.5	(10.2)	(0.2)	(39.9)	(151.0)	
	EE net replacements	(11.6)	32.8	25.7	(2.6)	(1.3)	7.5	3.3	(2.6)	(6.8)	(0.1)	1.0	0.0	10.0	(0.2)	(1.6)	(11.6)	
	RPM load management	7,264.5	2,427.9	1,183.9	444.5	57.4	410.0	154.8	198.0	735.2	99.0	1,400.1	246.5	470.4	159.1	143.0	665.1	
01-Jun-26	DR cleared	5,710.3	1,611.1	620.0	381.5	33.9	179.1	45.6	229.3	597.8	94.4	970.7	152.2	327.5	152.0	116.3	555.1	59.2
	DR net replacements	(18.3)	(5.3)	(0.5)	0.0	0.0	(0.5)	0.0	0.0	(12.0)	0.0	(0.2)	0.0	(1.9)	0.0	0.0	0.0	0.0
	RPM load management	5,692.0	1,605.8	619.5	381.5	33.9	178.6	45.6	229.3	585.8	94.4	970.5	152.2	325.6	152.0	116.3	555.1	59.2
01-Jun-27	DR cleared	7,298.6	1,981.6	799.8	455.5	42.6	234.3	49.1	285.9	672.3	101.7	1,515.9	169.6	421.8	172.1	200.6	768.3	89.3
	DR net replacements	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
	RPM load management	7,298.6	1,981.6	799.8	455.5	42.6	234.3	49.1	285.9	672.3	101.7	1,515.9	169.6	421.8	172.1	200.6	768.3	89.3

123 See OATT Attachment DD § 8.4. The reported DR cleared MW may reflect reductions in the level of committed MW due to relief from Capacity Resource Deficiency Charges.
124 Pursuant to OA § 15.1.6(c), PJM Settlement shall attempt to close out and liquidate forward capacity commitments for PJM Members that are declared in collateral default. The reported replacement transactions may include transactions associated with PJM members that were declared in collateral default.
125 EE resources are fully reflected in PJM load forecasts starting with the 2016 load forecast for the 2019/2020 delivery year, and EE resources are not defined to be capacity resources in any way as a result. EE resources do not clear in the capacity auctions.
126 See OATT Attachment DD § 5.14E. The reported DR cleared MW for the 2016/2017, 2017/2018, and 2018/2019 Delivery Years reflect reductions in the level of committed MW due to the Demand Response Legacy Direct Load Control Transition Provision.

Table 5-14 RPM commitments, replacements, and registrations for demand resources: June 1, 2007 to June 1, 2027[127 128 129]

	UCAP (MW)						Registered DR		
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM Commitment Shortage	RPM Commitments Less Commitment Shortage	ICAP (MW)	UCAP Conversion Factor	UCAP (MW)
01-Jun-07	127.6	0.0	0.0	127.6	0.0	127.6	0.0	1.033	0.0
01-Jun-08	559.4	0.0	(40.0)	519.4	(58.4)	461.0	488.0	1.034	504.7
01-Jun-09	892.9	0.0	(474.7)	418.2	(14.3)	403.9	570.3	1.033	589.2
01-Jun-10	962.9	0.0	(516.3)	446.6	(7.7)	438.9	572.8	1.035	592.6
01-Jun-11	1,826.6	0.0	(1,052.4)	774.2	0.0	774.2	1,117.9	1.035	1,156.5
01-Jun-12	8,752.6	(11.7)	(2,253.6)	6,487.3	(34.9)	6,452.4	7,443.7	1.037	7,718.4
01-Jun-13	10,779.6	0.0	(3,314.4)	7,465.2	(30.5)	7,434.7	8,240.1	1.042	8,586.8
01-Jun-14	14,943.0	0.0	(6,731.8)	8,211.2	(219.4)	7,991.8	8,923.4	1.042	9,301.2
01-Jun-15	15,774.8	(321.1)	(4,829.7)	10,624.0	(61.8)	10,562.2	10,946.0	1.038	11,360.0
01-Jun-16	13,284.7	(19.4)	(4,800.7)	8,464.6	(455.4)	8,009.2	8,961.2	1.042	9,333.4
01-Jun-17	11,870.7	0.0	(3,870.8)	7,999.9	(30.3)	7,969.6	8,681.4	1.039	9,016.3
01-Jun-18	11,435.4	0.0	(3,182.4)	8,253.0	(1.0)	8,252.0	8,512.0	1.091	9,282.4
01-Jun-19	10,703.1	0.0	(2,138.8)	8,564.3	(0.4)	8,563.9	9,229.9	1.090	10,056.0
01-Jun-20	9,445.7	0.0	(2,399.5)	7,046.2	(0.1)	7,046.1	7,867.6	1.088	8,561.5
01-Jun-21	11,427.7	0.0	(4,111.0)	7,316.7	0.0	7,316.7	7,754.2	1.087	8,429.6
01-Jun-22	8,866.2	0.0	(570.0)	8,296.2	(52.1)	8,244.1	8,518.5	1.091	9,290.2
01-Jun-23	8,174.1	0.0	(466.2)	7,707.9	(161.5)	7,546.4	7,383.0	1.093	8,069.6
01-Jun-24	8,064.7	0.0	(364.8)	7,699.9	(507.4)	7,192.5	6,758.7	1.117	7,549.5
01-Jun-25	6,265.9	0.0	(483.0)	5,782.9	(209.4)	5,573.5	7,748.7	0.770	5,966.5
01-Jun-26	5,710.3	0.0	(18.3)	5,692.0	0.0	5,692.0	0.0	0.720	0.0
01-Jun-27	7,298.6	0.0	0.0	7,298.6	0.0	7,298.6	0.0	0.920	0.0

ELCC: The Capacity Value of Resources

Given that many PJM states have aggressive renewable energy targets, a core goal of a competitive market design should be to ensure that the resources required to provide reliability receive appropriate competitive market incentives for entry and for ongoing investment and for exit when uneconomic. A significant level of renewable resources, operating with zero or near zero marginal costs, will result in very low energy prices at times of high intermittent output. Since renewable resources are intermittent, the contribution of renewables to meeting reliability targets must be analyzed carefully to ensure that the capacity value of renewables is calculated correctly.

The units of measurement for the PJM capacity market auctions are unforced capacity (UCAP). PJM uses conversion factors to convert installed capacity MW (ICAP) into UCAP MW and this process is known as capacity accreditation. Prior to the 2023/2024 Delivery Year, EFORd values for thermal generators were used to convert ICAP to UCAP. Conversion factors for wind and solar generators were based on energy output during summer peak

127 See OATT Attachment DD § 8.4. The reported DR adjustments to cleared MW include reductions in the level of committed MW due to relief from Capacity Resource Deficiency Charges.
128 See OATT Attachment DD § 5.14C. The reported DR adjustments to cleared MW for the 2015/2016 and 2016/2017 Delivery Years include reductions in the level of committed MW due to the Demand Response Operational Resource Flexibility Transition Provision.
129 See OATT Attachment DD § 5.14E. The reported DR adjustments to cleared MW for the 2016/2017, 2017/2018, and 2018/2019 Delivery Years include reductions in the level of committed MW due to the Demand Response Legacy Direct Load Control Transition Provision.

hours. Conversion factors for storage resources were equal to the maximum capability during 10 continuous hours of operation. The conversion factor for Demand Resources was equal to the forecast pool requirement (FPR). On July 30, 2021, FERC approved new PJM rules for defining/derating the capacity value of intermittent and storage resources, based on PJM's interpretation of the effective load carrying capability (ELCC) method.[130] PJM's average ELCC accreditations for intermittent and storage resources relied on the average capability by resource class for the 2023/2024 and 2024/2025 Delivery Years. Revisions, filed in October 2023, changed the capacity accreditation calculation to a marginal ELCC approach, applicable to all resource types. Beginning with the 2025/2026 Delivery Year, capacity accreditations are based on the revised marginal ELCC approach. The PJM marginal ELCC approach was accepted by FERC in January 2024.[131]

PJM's approach to ELCC is based on the correct high level insight that there is a need to calculate the availability of different resource types, but the actual implementation does not do that correctly and results in a set of illogical outcomes. For example, PJM assigned penalties to solar resources during Winter Storm Elliott in December 2022 when solar resources did not generate power after dark. PJM's ELCC calculations rely on a significant overweighting of generator performance during the Polar Vortex in 2014 and Winter Storm Elliott in 2022 that results in artificially suppressed ELCC values for thermal resources and other resource types.

Under the PJM ELCC approach a solar resource is assigned a derating factor, and the derated MW are asserted to be equivalent to a perfect resource accredited at that MW level. PJM assigned penalties to solar resources during Elliott when they did not generate power after dark. This is clearly not correct and illustrates one of the flaws in the ELCC logic. The solar resource is available for sunny hours and not for unsunny hours. A solar resource is not expected to generate at night and should not face penalties for failing to do what it obviously cannot. ELCC does not convert intermittent resources, or any resource, into a perfect resource, or even the equivalent of a perfect resource. This illogical implication of PJM's ELCC means that there is a significant flaw in the ELCC approach. The penalties were assessed because the ELCC method determined that 1 MW of solar nameplate capacity was equivalent to 0.54 MW of perfect capacity, meaning capacity that is always available at the derated level, even in the middle of the night.[132]

The MMU opposes PJM's ELCC rules because they are an administrative determination by PJM based on a black box model of the capacity value of resources, they rely on significant counterfactual behavioral assumptions for storage and demand response resources, are not unit specific, are not hourly, are not locational, introduce significant volatility to the capacity accreditations, do not recognize the winter capability of thermal resources, overweight unit performance during Winter Storm Elliott, do not recognize actual performance in the delivery year and are an ex ante approach that must assume a capacity resource fleet for determining the ELCC marginal class ratings.[133] PJM does not check the actual cleared capacity in capacity market auctions to verify if the cleared capacity is expected to provide the target reliability.

The ELCC approach is not an appropriate way to define the MW capacity value for intermittent and storage resources, or for thermal resources, in a market. ELCC was developed as, and remains, a utility planning tool rather than a market design tool. ELCC was attractive as a possible analytical basis for the derating of intermittent and storage resources to a MW level consistent with their actual availability. The impetus made sense but the actual application of the ELCC planning tool cannot work in markets that include intermittent or thermal resources. The underlying logic makes sense but PJM's implementation does not.

As a result of all these issues, the MMU has concluded that ELCC is not a viable method for determining the reliability contributions of capacity resources. The

130 See 176 FERC ¶ 61,056.
131 186 FERC ¶61,080 (January 30, 2024).
132 "ELCC Class Ratings for 2024-2025 BRA," PJM Interconnection L.L.C. (December 28, 2021) <https://www.pjm.com/planning/resource-adequacy-planning/effective-load-carrying-capability>.
133 See Protest of the Independent Market Monitor for PJM, Docket ER24-99-000, et al. (November 9, 2023); Comments on Response to Deficiency Notice, Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER24-99-000 (December 21, 2023); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER24-99-000 (January 12, 2024); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER24-99-000 (January 24, 2024).

MMU has proposed a replacement for the PJM ELCC approach that is based on the actual hourly availability of all individual generators.[134 135 136]

The ELCC ratings produced by the marginal approach in general, and by PJM's specific marginal approach specifically, are inherently volatile. PJM has calculated the marginal ELCC class ratings for the 2025/2026 delivery year on five separate occasions. Table 5-15 shows the results of each calculation. Each calculation is dependent upon the load forecast model, the combination of actual historical performance and changes in experienced weather, and the assumed forward looking resource mix. The PJM 2024 load forecast model was used to produce the February 2024, March 2024 and January 2025 ELCC ratings. The ELCC ratings posted on December 31, 2024, used an interim 2025 load forecast model. In early January, PJM removed the posted ELCC ratings from December 31, 2024, and posted recalculated ratings using the 2024 load forecast model. The modified ELCC ratings were posted on January 23, 2025. The January 23, 2025, ratings are the final ELCC ratings for 2025/2026 Delivery Year.[137] The ELCC rating changes have significant impacts on the amount of cleared capacity. Table 5-16 shows the difference between capacity that cleared the 2025/2026 Base Residual Auction and the updated capacity MW value based on the final ELCC ratings for 2025/2026 posted on January 23, 2025. In total, the capacity values decreased by 928.5 MW (UCAP) or 0.7 percent. Capacity market sellers are obligated to obtain additional capacity prior to the delivery year if they are short as a result of a reduction in ELCC rating between the BRA and the final ELCC rating from PJM's ELCC rating changes. Had PJM used the ELCC ratings posted on December 31, 2024, the capacity values would have decreased by 3,793.3 MW or 2.8 percent.

Table 5-15 Marginal ELCC ratings for the 2025/2026 Delivery Year

	2025/2026 Delivery Year				
ELCC Class	December 2023	February 2024	March 2024	December 2024	January 2025
Onshore Wind	21%	35%	35%	42%	38%
Offshore Wind	39%	60%	60%	71%	62%
Solar Fixed	15%	9%	9%	8%	10%
Solar Tracking	25%	14%	14%	11%	14%
Landfill Intermittent	56%	55%	54%	51%	51%
Hydro Intermittent	41%	36%	37%	37%	37%
4-hr Storage	76%	59%	59%	44%	55%
6-hr Storage	85%	67%	67%	53%	65%
8-hr Storage	89%	69%	68%	58%	68%
10-hr Storage	92%	78%	78%	67%	77%
Demand Response	95%	77%	76%	68%	77%
Nuclear	96%	96%	95%	95%	95%
Coal	86%	85%	84%	83%	83%
Gas Combined Cycle	87%	80%	79%	77%	78%
Gas Combustion Turbine	74%	62%	62%	59%	63%
Gas Combustion Turbine Dual Fuel	90%	78%	79%	78%	79%
Diesel Utility	91%	90%	92%	92%	92%
Steam	78%	70%	75%	73%	74%

Table 5-16 Impact of ratings changes on cleared capacity[138]

	MW (UCAP)	Reduction in capacity value compared to Base Residual Auction	Percent change in capacity value compared to Base Residual Auction
2025/2026 Base Residual Auction Cleared Capacity	135,684.0		
Updated Cleared Capacity based on Jan 23, 2025 ELCC Ratings	134,755.5	(928.5)	(0.7%)
Updated Cleared Capacity based on Dec 31, 2024 ELCC Ratings	131,890.7	(3,793.3)	(2.8%)

The ELCC volatility also affects the reliability requirement calculation. Table 5-17 shows the reliability requirement calculation for the 2025/2026 RPM Base Residual Auction and the update for the Third Incremental Auction for 2025/2026. The pool wide accredited UCAP factor for the Third IA is based on the January 23, 2025, ELCC ratings which use the PJM 2024 load forecast model. These updated ELCC ratings reduced the pool wide accredited

134 For additional details on the MMU proposal see "Executive Summary of the IMM Capacity Market Design Proposal: Sustainable Capacity Market (SCM)", Independent Market Monitor for PJM (August 16, 2023) <http://www.monitoringanalytics.com/reports/Presentations/2023/IMM_RASTF-CIFP_SCM_Executive_Summary_20230816.pdf>.

135 Any generation from a resource in excess of its CIR value is equivalent to generation from an energy only resource and should not be included in the calculation of the capacity value of the resource or in the calculation of the derated ELCC class ratings that define the capacity value of the resource. Updated rules beginning with the 2025/2026 Delivery Year require that ELCC accreditations exclude energy in excess of a generator's CIR. See 183 FERC ¶ 61,009 (April 7, 2023).

136 New rules beginning with the 2025/2026 Delivery Year correctly limit the delivered energy to the CIR level in the ELCC calculations. The new rules also include a complex transition process that allocates available headroom to intermittent resources with understated CIRs. The new rules apply to Delivery Year 2025/2026 BRA and subsequent delivery years. *See* 183 FERC ¶ 61,009 (April 7, 2023).

137 See Item 5 in Markets and Reliability Committee Meeting Materials, *Installed Reserve Margin (IRM), Forecast Pool Requirement (FPR), and Effective Load Carrying Capability (ELCC) for 2025/2026 3IA* at 2, PJM Interconnection L.L.C. (January 23, 2025) <https://www.pjm.com/committees-and-groups/committees/mrc>.

UCAP factor from 0.7969 to 0.7963. The reliability requirement and the FRR obligation both increase, resulting in an increase of 395.7 MW (UCAP) to the reliability requirement adjusted for FRR. PJM needs to procure an additional 395.7 MW (UCAP) of capacity in the Third Incremental Auction.

Table 5-17 PJM Reliability Requirement[139 140 141]

	2025/2026 Base Residual Auction	2025/2026 Third Incremental Auction	Change
ICAP	191,693.0	188,920.0	(2,773.0)
Solved Load	160,624.0	158,357.0	(2,267.0)
Installed Reserve Margin	17.800%	17.800%	0.0%
Accredited UCAP	152,765.0	150,438.0	(2,327.0)
Pool Wide Accredited UCAP Factor	0.797	0.796	(0.001)
Forecast Pool Requirement	0.939	0.938	(0.001)
Preliminary Forecast Peak Load	153,883.0	154,534.1	651.0
Reliability Requirement	144,450.0	144,953.0	503.0
Fixed Resource Requirement (FRR)	10,886.4	10,993.7	107.3
Reliability Requirement Adjusted for FRR	133,563.6	133,959.3	395.7

PJM filed tariff changes that transfer risk caused by the volatile ELCC ratings from generation owners to the load. ELCC ratings may increase or decrease significantly between the time a generator clears in the RPM Base Residual Auction and the final ELCC rating just prior to the start of the delivery year. Under the new tariff rules, generators will be excused from paying the Capacity Resource Deficiency Charge for a deficiency caused by a decrease in the final ELCC rating. Under the prior rules, a Capacity Market Seller was required to cover its short position by acquiring additional capacity or pay a deficiency penalty equal to 20 percent of the base residual auction clearing price for each MW of shortage. The tariff change was filed by PJM on April 18, 2025, and approved by FERC on June 17, 2025.[142 143] The MMU opposed the change because the new rule does not mitigate the risk as asserted by PJM but simply transfers the ELCC rating volatility risk to the load.[144] The change is inconsistent with basic market logic under which investors bear the risk associated with the ownership of generation. The new rules are effective beginning with the 2026/2027 Delivery Year.

PJM has calculated and posted marginal ELCC ratings on 11 occasions for the 2025/2026 through 2028/2029 Delivery Years. Figure 5-5 shows the ELCC class ratings for intermittent resources. The horizontal axis shows the delivery year to which the ratings apply and the month the ratings were posted. The ratings change each time they are recalculated. The original rating for onshore wind for the 2025/2026 Delivery Year was 21 percent and the final rating for 2025/2026 Delivery Year was 38 percent, an 80.9 percent increase. The onshore wind rating for the 2027/2028 Delivery Year is 41 percent, a 95.2 percent increase over the initial 2025/2026 rating. Solar has decreased. Solar with tracking technology has decreased from the initial 2025/2026 rating of 25 percent to 8 percent for the 2027/2028 Delivery Year, a 68.0 percent decrease. Solar with fixed panels has decreased 53.3 percent over the same period.

138 PJM stated that the 2024 load forecast model was used because it is the "most recently finalized PJM load forecast." The January 23, 2025, ELCC Ratings are based on the PJM 2024 load forecast model. The December 31, 2024, ELCC Ratings are based on an interim PJM 2025 load forecast model.

139 *2025/2026 RPM 3rd Incremental Auction Planning Parameters*, PJM Interconnection L.L.C. (January 31, 2025) <https://www.pjm.com/markets-and-operations/rpm>.

140 *Installed Reserve Margin (IRM), Forecast Pool Requirement (FPR), and Effective Load Carrying Capability (ELCC) for BRA* at 15, Item 5, PJM Markets & Reliability Committee meeting, PJM Interconnection L.L.C. (March 20, 2024). <https://www.pjm.com/committees-and-groups/committees/mrc>.

141 *Installed Reserve Margin (IRM), Forecast Pool Requirement (FPR), and Effective Load Carrying Capability (ELCC) for 3IA* at 7, Item 3, PJM Members Committee meeting, PJM Interconnection L.L.C. (January 23, 2025). <https://www.pjm.com/committees-and-groups/committees/mc>.

142 *Proposal to Mitigate Impacts From Updates to ELCC Accreditation between the Base Residual Auction and the Final ELCC Accreditation Values*, PJM Interconnection L.L.C., Docket ER25-2002 (April 18, 2025).

143 191 FERC ¶ 61,203 (June 17, 2025).

144 See *Comments of the Independent Market Monitor for PJM* (May 9, 2025), *Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM* (June 9, 2025), *Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM* (June 16, 2025), Docket ER25-2002-000).

Figure 5-5 Marginal ELCC Class Ratings for Intermittent Resources

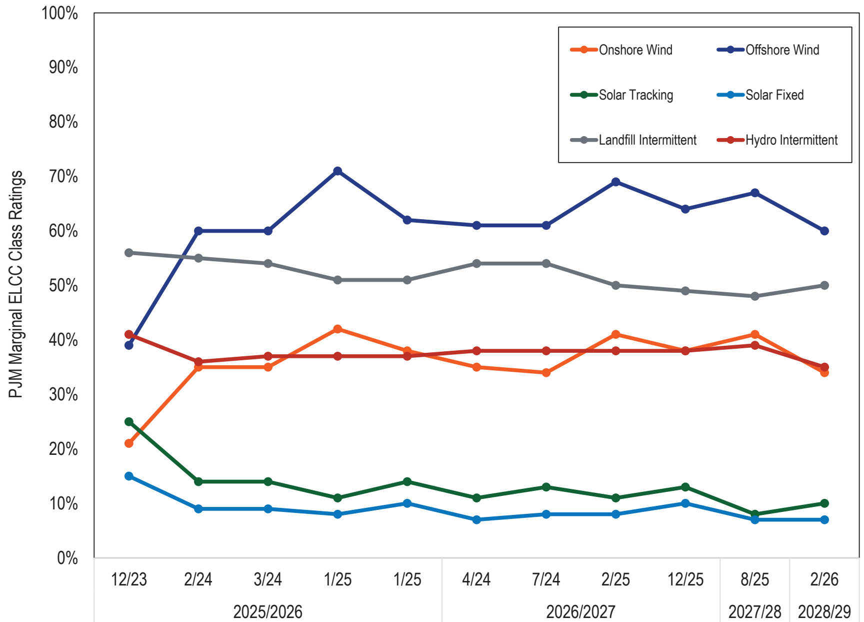
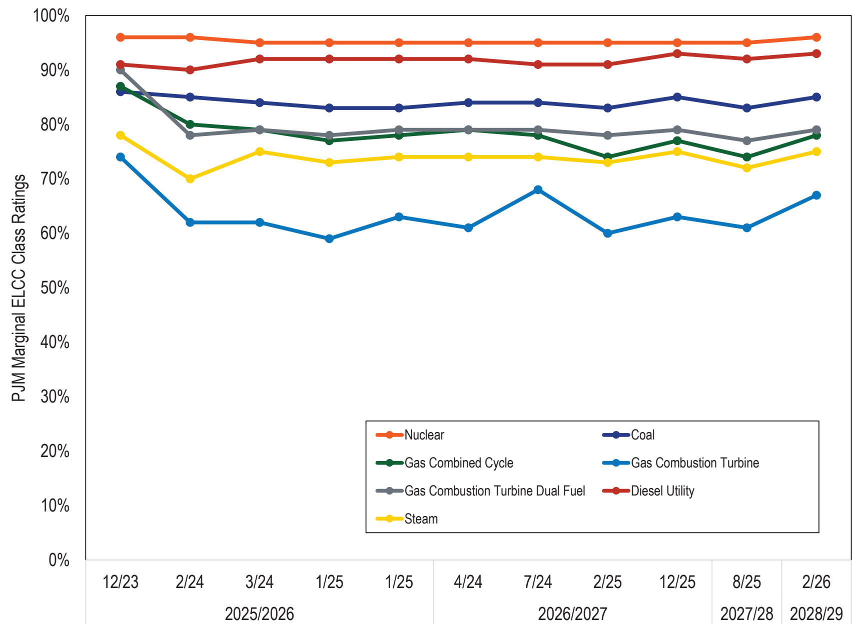


Figure 5-6 shows the ELCC rating for thermal resources. Combined cycle resource and combustion turbine ratings have decreased from their initial 2025/2026 ratings. The original rating for combined cycle resources for the 2025/2026 Delivery Year was 87 percent and the final rating for 2025/2026 Delivery Year was 78 percent, a 10.3 percent decrease. The combined cycle rating for the 2027/2028 Delivery Year is 74 percent, a 14.9 percent decrease over the initial 2025/2026 rating. Combustion turbine ratings have also decreased. Ratings for combustion turbines with dual fuel capability have decreased from the initial 2025/2026 rating of 90 percent to 77 percent for the 2027/2028 Delivery Year, a 14.4 percent decrease. Ratings for combustion turbines without dual fuel capability have decreased 17.6 percent over the same period. The change in UCAP for combined cycle and combustion turbine resources from the initial 2025/2026 ELCC ratings to the latest 2027/2028 ratings is a decrease of 11.5 GW. The corresponding change in ICAP is a decrease of 1.2 GW.

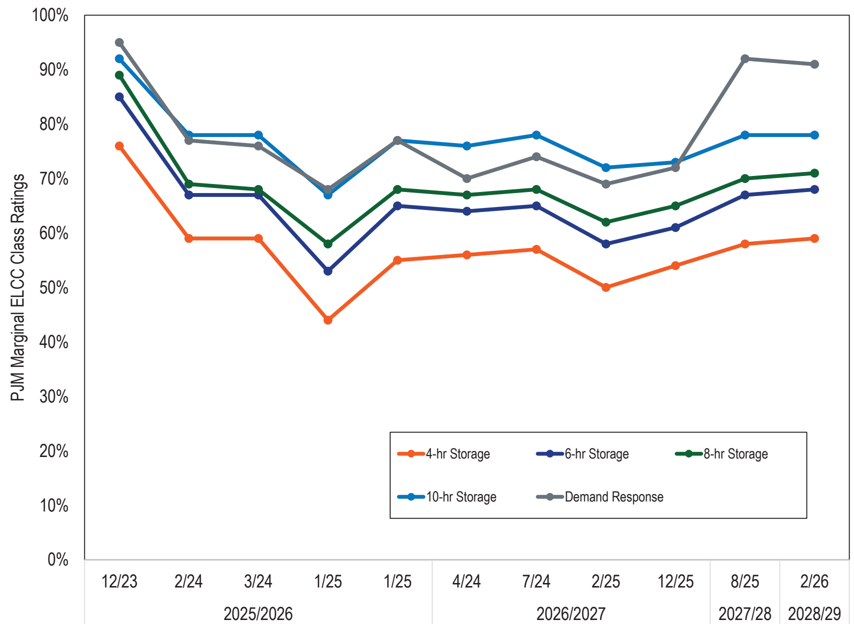
PJM could partially offset this loss of capacity in the short run by recognizing the winter capability of thermal resources rather than limiting such resources to summer ratings. Most of the risk recognized in the ELCC model is winter risk but the ELCC accreditation values for thermal resources are capped at the summer ratings. That unnecessarily limits supply and changes the ELCC values for all other resources and changes the system accredited unforced capacity and therefore AUCAP, the maximum level of load that can be served by the existing resources and therefore the reliability requirement. The CIRs of such resources are currently limited by the summer ratings but those rules can and should be changed given the use of the ELCC approach. There is no reason that excess winter CIRs cannot be assigned to these resources immediately.

Figure 5-6 Marginal ELCC Class Ratings for Thermal Resources



Marginal ELCC ratings for storage and demand response resources have also exhibited volatility. Figure 5-7 shows that the storage resource ratings have decreased. On average across all durations, storage ELCC ratings have decreased 20.4 percent from the initial 2025/2026 Delivery Year ratings to the 2027/2028 Delivery Year ratings. The initial rating for demand response for the 2025/2026 Delivery Year was 95 percent and final rating for the 2025/2026 Delivery Year was 77 percent, an 18.9 percent decrease. Due to recent rule change, the demand response rating for the 2027/2028 Delivery Year is 92 percent.[145]

Figure 5-7 Marginal ELCC Class Ratings for Storage and Demand Resources



145 191 FERC ¶61,103 (May 5, 2025).

Market Conduct

Offer Caps

Market power mitigation measures were applied to capacity resources such that the sell offer was set equal to the defined offer cap when the capacity market seller failed the market structure test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would have increased the market clearing price.[146] [147] [148] For Capacity Performance Resources, for RPM auctions prior to September 2, 2021, offer caps were defined in the PJM Tariff as the applicable zonal Net Cost of New Entry (CONE) times (B) where B is the average of the Balancing Ratios (B) during the Performance Assessment Hours in the three consecutive calendar years that precede the base residual auction for such delivery year, unless net avoidable costs exceed this level, or opportunity costs based on the potential sale of capacity in an external market exceed this level. The Commission issued an order eliminating the prior offer cap and establishing a competitive market seller offer cap set at Net ACR, effective September 2, 2021.[149] The Commission rejected an attempt by PJM to undermine the Market Seller Offer Cap rules by order issued February 6, 2024.[150] The Commission approved changes to the Market Seller Offer Cap that allow Capacity Market Sellers to offer the higher of the net ACR and the Capacity Performance Quantifiable Risk (CPQR)[151] and to submit resource specific segmented offer caps.[152] Both changes to the Market Seller Offer Cap give Capacity Market Sellers the ability to offer in excess of the competitive offer and exercise market power as a result.

For RPM Third Incremental Auctions prior to September 2, 2021, capacity market sellers may elect an offer cap equal to the greater of the Net CONE for

146 See OATT Attachment DD § 6.5.
147 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).
148 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).
149 176 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), *cert. denied*.
150 186 FERC ¶ 61,097, *reh'g denied*, 187 FERC ¶ 62,016 (2024).
151 190 FERC ¶ 61,117 (February 20, 2025).
152 Id. at 123.

the relevant LDA and delivery year or 1.1 times the BRA clearing price for the relevant LDA and delivery year. For RPM Third Incremental Auctions after September 2, 2021, capacity market sellers may elect an offer cap of 1.1 times the BRA clearing price for the relevant LDA and delivery year.

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 costs that a generation owner incurs as a result of operating a generating unit for one year, in particular the delivery year.[153] As a result, the tariff defines avoidable costs as the costs that a generation owner would not incur if the generating unit did not offer for one year. Although the term mothball is used in the tariff to modify the term ACR, the term mothball is not defined in the tariff. Mothball is an informal term better understood as a metaphor for the cost to operate for one year. Avoidable costs are the costs to operate the unit for one year, regardless of whether the unit plans to retire. Although the tariff includes different mothball and retirement values, the distinction is based on a misunderstanding of the meaning of avoidable costs and should be eliminated. PJM never explained exactly how it calculated mothball and retirement avoidable cost levels. 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.[154] The tariff states that avoidable costs may also include annual capital recovery associated with investments required to maintain a unit as a Generation Capacity Resource, termed Avoidable Project Investment Recovery (APIR), despite the fact that these are not actually avoidable costs, particularly after the first year.

Avoidable cost based offer caps are defined to be net of revenues from all other PJM markets and unit-specific bilateral contracts, including RECs, and expected bonus performance payments/nonperformance charges.[155] Capacity resource owners could provide ACR data by providing their own unit-specific data or, for auctions for delivery years prior to 2020/2021 and auctions held after September 2, 2021, by selecting the default ACR values. The specific components of avoidable costs are defined in the PJM tariff.[156]

Effective for the 2018/2019 and subsequent delivery years, the ACR definition includes two additional components, Avoidable Fuel Availability Expenses (AFAE) and Capacity Performance Quantifiable Risk (CPQR).[157] AFAE is available for Capacity Performance Resources. AFAE is defined to include expenses related to fuel availability and delivery. CPQR is available for Capacity Performance Resources and, for the 2018/2019 and 2019/2020 Delivery Years, Base Capacity Resources. CPQR is defined to be the quantifiable and reasonably supported cost of mitigating the risks of nonperformance associated with submission of an offer.

The opportunity cost option allows capacity market sellers to offer based on a documented price available in a market external to PJM, subject to export limits. If the relevant RPM market clears above the opportunity cost, the generation capacity resource is sold in the RPM market. If the opportunity cost is greater than the clearing price and the generation capacity resource does not clear in the RPM market, it is available to sell in the external market.

Effective with the 2026/2027 Delivery Year, the market seller offer cap definition was modified to include unit specific standalone Capacity Performance Quantifiable Risk (CPQR) and segmented unit specific offer caps.[158] For standalone CPQR, the offer cap is defined as the unit specific CPQR with no net revenue offset applied. For segmented unit specific offer caps, the capacity market seller can request that the first segment of the segmented unit specific offer cap be based on either unit specific standalone CPQR or net unit specific ACR. The remaining segments from the second segment up to the tenth segment are defined to be based on standalone CPQR.[159]

Allowing offers based on gross CPQR when net revenues are greater than total gross ACR, including CPQR, permits offers greater than the competitive level by allowing resources with a competitive offer of $0 per MW-day to make positive offers equal to one component of ACR, the gross CPQR component,

153 OATT Attachment DD § 6.8(b).
154 *PJM Interconnection L.L.C., Docket Nos. ER19-210-000 and EL19-8-000, Responses to Deficiency Letter re: Major Maintenance and Operating Costs Recovery* (February 14, 2019).
155 For details on the competitive offer of a capacity performance resource, 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).
156 OATT Attachment DD § 6.8(a).
157 151 FERC ¶ 61,208 (2015).
158 190 FERC ¶ 61,117 (2025).
159 OATT Attachment DD § 6.4(e)

ignoring net revenues entirely. The rule also permits offers greater than the competitive level by allowing resources with a competitive offer greater than $0 per MW-day but less than gross CPQR to make offers equal to one standalone component of ACR, the gross CPQR component, also ignoring net revenues entirely.

The decision to allow segmented offer caps means allowing the exercise of market power. This is the case first because the segmented offer caps require that all avoidable costs be spread over a first MW segment that is smaller than the full resource, thus inflating the MSOC, and allow offer caps for all segments after the first segment based on gross CPQR with no net revenue offsets. If avoidable costs can be assigned to the first, self defined MW offer segment, and the later MW segments are not defined in the rules, MSOCs are meaningless. Assigning gross CPQRs and no net revenues to one or more undefined MW tail blocks would permit offers that exceed the correctly calculated MSOC by multiples and would permit the exercise of market power. The rule does not use any net revenue offset for the CPQR segments. The competitive level is defined as total gross avoidable costs, net of net revenues, divided by the total MW in the offer.

On October 17, 2024, the Commission issued a final rule, Order No. 904, eliminating separate payments for reactive in all jurisdictional markets, including PJM.[160] As a result, effective with the 2026/2027 Delivery Year, reactive revenues are not included in the net revenue offset for RPM purposes including the VRR curve, market seller offer caps, and MOPR floors.[161]

Competitive Offers

The competitive offer of a capacity resource is based, regardless of tariff requirements, on a market seller's expectations of the resource's net going forward costs (net ACR) which are the net of the resource's gross ACR and the resource's forward looking net revenues. The gross ACR includes the cost to mitigate the resource's risk of incurring performance assessment penalties (CPQR).

The competitive offer is based on a forward looking energy and ancillary services (E&AS) net revenue offset rather than the backward looking E&AS net revenue offset currently in the tariff. Forward prices for energy prices and fuel prices are a better guide to market expectations than historical energy and fuel prices but both sources of information should be incorporated. This is particularly important in years, like 2022, when there is a significant change from the historical level of energy market prices. The forward curves reflect this change, but the historical prices do not. However, the PJM method for calculating forward looking net revenues is significantly flawed and overestimates net revenues.

PJM had a forward looking net revenue calculation in the tariff that applied to RPM Auctions for the 2022/2023 Delivery Year.[162] FERC subsequently reversed its approval of that method as part of rejecting PJM's ORDC filing.[163] PJM's method for calculating forward looking E&AS net revenues was flawed for several reasons. PJM's method included an adjustment based on the prices of long term FTRs for the planning period closest in time to the delivery year which requires an adjustment for monthly average day-ahead congestion price differentials and an adjustment for loss component differentials of historical LMPs. Use of the adjustment based on the prices of long term FTRs adds unnecessary complexity, fails to make the result more accurate, makes the results less transparent, and in some cases make the results less accurate. PJM's use of long term FTRs in the forward energy market price calculation does not use the FTR auction for the desired delivery year as a result of the timing of capacity auctions and FTR auctions when PJM is on its defined three year capacity market auction schedule. It would be simpler, more accurate and more transparent to use forward LMPs calculated using real-time monthly on and off peak forward prices for the delivery year at the PJM Western Hub, adjusted to the zone and hour using the historical zonal, nodal and hourly real-time price differentials for each of the last three years. The MMU and PJM have been implementing this method for years in the calculation of the

160 *Compensation for Reactive Power within the Standard Power Factor Range*, Order No. 904, 189 FERC ¶ 61,034 (2024) ("Order No. 904").
161 See Letter Order, FERC Docket No. ER25-682-001 (April 29, 2025).

162 171 FERC ¶ 61,153 (May 21, 2020) and 173 FERC ¶ 61,134 (November 12, 2020).
163 Forward energy and ancillary services (E&AS) revenue offsets were applicable from November 12, 2020, as approved in the FERC Order on compliance in Docket Nos. EL19-58-002 and EL19-58-003 until December 22, 2021, when the Commission issued an Order on Voluntary Remand in Docket Nos. EL19-58-006 and ER19-1486-003 reversing its prior determination that PJM should use a forward looking energy E&AS revenue offset and directing PJM to submit a compliance filing restoring the tariff provisions defining the historical E&AS revenue offset.

opportunity costs associated with environmental limits on the operation of generating units.[164]

More fundamentally, PJM's forward looking net revenue calculation tends to overestimate forward net revenues. The PJM method is based on a theoretical, unit by unit perfect dispatch based on unit parameters and forward fuel costs and LMPs. The PJM method fails to account for the realities of committing and dispatching units. Nonetheless, it remains correct that generation owners look forward and not backwards when calculating net revenues. The goal is an approach that retains the reality of historical commitment and dispatch while recognizing that future conditions will be different. A better approach would calculate unit forward looking expected energy and ancillary services net revenues using historical revenues that are scaled based on a comparison of forward prices for energy and fuel to the historical prices for energy and fuel.

The competitive offer of a capacity resource is based on a market seller's expectations of market variables during the delivery year, the impact of these variables on the resource's risk, and the cost to mitigate that risk. These market variables are: the number of performance assessment intervals (PAI) in a delivery year where the resource is located; the level of performance required to meet its capacity obligation during those performance assessment intervals, measured as the average Balancing Ratio (B); and the level of the bonus performance payment rate (CPBR) compared to the nonperformance charge rate (PPR). The total capacity revenues earned by a resource are the sum of revenues earned in the forward capacity auctions and additional bonus revenues earned (or penalties paid) during the delivery year, which are a function of unit performance during PAI (A). The level of the bonus performance payment rate depends on the level of underperforming MW net of the underperforming MW excused by PJM during performance assessment intervals for reasons defined in the PJM OATT.[165]

The September 2, 2021, Commission order addressed the definition of the market seller offer cap by eliminating the net CONE times B offer cap and establishing a competitive market seller offer cap of net ACR.[166] The Commission rejected a more recent attempt by PJM to undermine the Market Seller Offer Cap rules by order issued February 6, 2024.[167]

In February 2025, PJM filed, and FERC approved, changes to the Market Seller Offer Cap that allow Capacity Market Sellers to offer the higher of the net ACR and the Capacity Performance Quantifiable Risk (CPQR).[168] The changes also allow Capacity Market Sellers to submit resource specific segmented offer caps.[169] Both changes to the Market Seller Offer Cap give Capacity Market Sellers the ability to offer in excess of the competitive offer.

Allowing offers based on gross CPQR when net revenues are greater than total gross ACR, including CPQR, permits offers greater than the competitive level by allowing resources with a competitive offer of $0 per MW-day to make positive offers equal to one component of ACR, the gross CPQR component, ignoring net revenues entirely. The rule also permits offers greater than the competitive level by allowing resources with a competitive offer greater than $0 per MW-day but less than gross CPQR to make offers equal to one standalone component of ACR, the gross CPQR component, also ignoring net revenues entirely.

The decision to allow segmented offer caps means allowing the exercise of market power. This is the case first because the segmented offer caps require that all avoidable costs be spread over a first MW segment that is smaller than the full resource, thus inflating the MSOC, and allow offer caps for all segments after the first segment based on gross CPQR with no net revenue offsets. If avoidable costs can be assigned to the first, self defined MW offer segment, and the later MW segments are not defined in the rules, MSOCs are meaningless. Assigning gross CPQRs and no net revenues to one or more undefined MW tail blocks would permit offers that exceed the correctly calculated MSOC by multiples and would permit the exercise of market power. The rule does not use any net revenue offset for the CPQR segments. The

164 *See* "PJM Manual 15: Cost Development Guidelines," § 12.7 IMM Opportunity Cost Calculator, Rev. 47 (Oct. 1, 2025).
165 OATT Attachment DD § 10A (d).
166 176 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).
167 186 FERC ¶ 61,097, *reh'g denied*, 187 FERC ¶ 62,016 (2024).
168 190 FERC ¶ 61,117 (February 20, 2025).
169 Id. at 123.

competitive level is defined as total gross avoidable costs, net of net revenues, divided by the total MW in the offer.

2026/2027 RPM Third Incremental Auction

As shown in Table 5-18, 985 generation resources submitted Capacity Performance offers in the 2026/2027 RPM Third Incremental Auction. Unit specific offer caps were calculated for four generation resources (0.4 percent). Of the 985 generation resources, 816 generation resources elected the offer cap option of 1.1 times the BRA clearing price (82.8 percent), four generation resource had unit specific ACR based offer caps (0.4 percent), 13 Planned Generation Capacity Resources had uncapped offers (1.3 percent), and the remaining 152 generation resources were price takers (15.4 percent). Market power mitigation was applied to zero Capacity Performance sell offers.

Table 5-18 ACR statistics: RPM auctions held in first quarter, 2026

	2026/2027 Third Incremental Auction	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	0	0.0%
Unit specific ACR (APIR)	4	0.4%
Unit specific ACR (APIR and CPQR)	0	0.0%
Unit specific ACR (non-APIR)	0	0.0%
Unit specific ACR (non-APIR and CPQR)	0	0.0%
Unit specific standalone CPQR	NA	NA
Unit specific segmented offer caps	NA	NA
Opportunity cost input	0	0.0%
Default ACR and opportunity cost	0	0.0%
Offer cap of 1.1 times BRA clearing price elected	816	82.8%
Uncapped planned uprate and default ACR	0	0.0%
Uncapped planned uprate and opportunity cost	0	0.0%
Uncapped planned uprate and price taker	0	0.0%
Uncapped planned uprate and 1.1 times BRA clearing price elected	0	0.0%
Uncapped planned generation resources	13	1.3%
Existing generation resources as price takers	152	15.4%
Total Generation Capacity Resources offered	985	100.0%

MOPR

By order issued December 19, 2019, the RPM Minimum Offer Price Rule (MOPR) was modified.[170] The rules applying to natural gas fired capacity resources without state subsidies were retained. The changes included expanding the MOPR to new or existing state subsidized capacity resources; establishing a competitive exemption for new and existing resources other than natural gas fired resources while also allowing a resource specific exception process for those that do not qualify for the competitive exemption; defining limited categorical exemptions for renewable resources participating in renewable portfolio standards (RPS) programs, self supply, DR, EE, and capacity storage; defining the region subject to MOPR for capacity resources with state subsidy as the entire RTO; and defining the default offer price floor for capacity resources with state subsidies as 100 percent of the applicable Net CONE or net ACR values.

On September 29, 2021, PJM's FPA section 205 filing in Docket No. ER21-2582-000 revising the Minimum Offer Price Rule (MOPR) was made effective by operation of law.[171] The revised MOPR in OATT Attachment DD § 5.14(h-2) became effective for RPM auctions for the 2023/2024 and subsequent delivery years. Under the revised MOPR, a generation resource would be subject to an offer floor if the capacity is deemed to meet the definition of Conditioned State Support or if the capacity market seller plans to use the resource to exercise Buyer-Side Market Power as the term is defined in the tariff through either self certification or a fact specific review initiated by the MMU or PJM. Whether a state program or policy qualifies for Conditioned State Support would be the result of a Commission determination.

The PJM markets would be better off, more competitive, and more efficient with no MOPR than with PJM's approach. PJM's proposal effectively eliminated the MOPR while creating a confusing and inefficient administrative process that effectively makes it both unnecessary and impossible to prove buyer side market power as PJM has defined it.[172]

170 169 FERC ¶ 61,239 (2019), *order denying reh'g*, 171 FERC ¶ 61,035 (2020), *aff'd* PJM Power Providers Group, et al. v. FERC, Case No. 21-3068 (3rd Cir. December 1, 2023), *cert denied.*
171 *PJM Interconnection, L.L.C*, Notice of Filing Taking Effect by Operation of Law, Docket No. ER21-2582 (September 29, 2021).
172 See Protest of the Independent Market Monitor for PJM, Docket No. ER21-2582-000 (August 20, 2021); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER21-2582-000 (September 22, 2021).

The current form of the MOPR has no meaningful impact. The only function the current MOPR is serving now is to create unnecessary administrative work in the application and compliance screening and to create barriers to entry for generation resources. Generation resources that miss a certification deadline to check a box that they are not receiving state conditioned support and will not exercise market power are then required to offer at uncompetitive net CONE levels or are not allowed to offer because the applicable MOPR floor exceeds the offer cap or no default MOPR floor for the technology is defined. Absent a meaningful change to MOPR, the MMU recommends eliminating the MOPR.

MOPR Statistics

Under the applicable MOPR rules, market power mitigation measures were applied to MOPR Screened Generation Resources such that the sell offer is set equal to the MOPR Floor Offer Price when the submitted sell offer is less than the MOPR Floor Offer Price and an exemption or exception was not granted, or the sell offer is set equal to the agreed upon minimum level of sell offer when the sell offer is less than the agreed upon minimum level of sell offer based on a Unit-Specific Exception or Resource-Specific Exception.

As shown in Table 5-19, there were no unit specific exception requests for MOPR under OATT Attachment DD § 5.14(h-2) for the 2025/2026 RPM Third Incremental Auction. Of the 14.7 MW offered in the 2026/2027 RPM Third Incremental Auction that were subject to MOPR, 14.6 MW cleared and 0.1 MW did not clear.

Table 5-19 MOPR statistics: RPM auctions held in first quarter, 2026

				ICAP (MW)			UCAP (MW)	
	MOPR Type	Calculation Type	Number of Requests	Requested	MMU Agreed	Offered	Offered	Cleared
2026/2027 Third Incremental Auction	OATT Attachment DD § 5.14(h-2)	Unit Specific Exception	0	0.0	0.0	0.0	0.0	0.0
	OATT Attachment DD § 5.14(h-2)	Default	NA	NA	NA	63.8	14.7	14.6
	Total		0	0.0	0.0	63.8	14.7	14.6

Replacement Capacity[173]

When a capacity resource is not available for a delivery year, the owner of the capacity resource may purchase replacement capacity. Replacement capacity is the vehicle used to offset any reduction in capacity from a resource which is not available for a delivery year. But the replacement capacity mechanism may also be used to manipulate the market.

Table 5-20 shows the committed and replacement capacity for all capacity resources for June 1 of each year from 2007 through 2027.

Sellers of demand resources in RPM auctions disproportionately replace those commitments on a consistent basis compared to sellers of other resource types. External generation and internal generation not in service had high rates of replacement in some years and those are also of concern.

The dynamic that can result is that the speculative DR suppresses prices in the BRA and displaces physical generation assets. Those generation assets then have an incentive to offer at a low price, including offers at zero and below cost, in IAs in order to ensure some capacity market revenue for long lived physical

173 For more details on replacement capacity, 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).

resources which the owners expect to maintain for multiple years. The result is lower IA prices which permit the buyback of the speculative DR at prices below the BRA prices which encourages the greater use of speculative DR.

PJM's sale of capacity in IAs at very low prices, given that PJM announces the MW quantity and the sell offer price in advance of the auctions, further reduces IA prices and increases the incentive of DR sellers to speculate in the BRAs. The MMU recommends that if PJM sells capacity in incremental auctions, PJM should offer the capacity for sale at the BRA clearing price in order to avoid suppressing the IA price below the competitive level. If the PJM sell offer price is not the BRA clearing price, PJM should not reveal its proposed sell offer price or the MW quantity to be sold prior to the auction.

It has been asserted that selling at a high price in the BRA and buying back at a low price in the IA is just a market transaction and therefore does not constitute a problem. But permitting DR to be an option in the BRA rather than requiring DR to be a commitment to provide a physical asset gives DR an unfair advantage and creates a self fulfilling dynamic that incents more of the same behavior. Only DR is permitted to be an option in the BRA. Generation resources must have met physical milestones in order to offer in the BRA. It is not reasonable to permit DR capacity resources to have a different product definition than generation capacity resources. Even if DR is treated as an annual product, this unique treatment as an option makes DR an inferior resource and not a complete substitute for generation resources. The current approach to DR is also inconsistent with the history of the definition of capacity in PJM, which has always been that capacity is physical and unit specific. The current approach to DR effectively makes DR a virtual participant in the PJM Capacity Market. That option should be eliminated.

The definition of demand side resources in PJM capacity markets is flawed in a variety of ways. The current demand side definition should be replaced with a definition that includes demand on the demand side of the market. There are ways to ensure and enhance the vibrancy of demand side without negatively affecting markets for generation.

Table 5-20 RPM commitments and replacements for all Capacity Resources: June 1, 2007 to June 1, 2027

	UCAP (MW)					
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM Commitment Shortage	RPM Commitments Less Commitment Shortage
01-Jun-07	129,409.2	0.0	0.0	129,409.2	(8.1)	129,401.1
01-Jun-08	130,629.8	0.0	(766.5)	129,863.3	(246.3)	129,617.0
01-Jun-09	134,030.2	0.0	(2,068.2)	131,962.0	(14.7)	131,947.3
01-Jun-10	134,036.2	0.0	(4,179.0)	129,857.2	(8.8)	129,848.4
01-Jun-11	134,182.6	0.0	(6,717.6)	127,465.0	(79.3)	127,385.7
01-Jun-12	141,295.6	(11.7)	(9,400.6)	131,883.3	(157.2)	131,726.1
01-Jun-13	159,844.5	0.0	(12,235.3)	147,609.2	(65.4)	147,543.8
01-Jun-14	161,214.4	(9.4)	(13,615.9)	147,589.1	(1,208.9)	146,380.2
01-Jun-15	173,845.5	(326.1)	(11,849.4)	161,670.0	(1,822.0)	159,848.0
01-Jun-16	179,773.6	(24.6)	(16,157.5)	163,591.5	(924.4)	162,667.1
01-Jun-17	180,590.5	0.0	(13,982.7)	166,607.8	(625.3)	165,982.5
01-Jun-18	175,996.0	0.0	(12,057.8)	163,938.2	(150.5)	163,787.7
01-Jun-19	177,064.2	0.0	(12,300.3)	164,763.9	(9.3)	164,754.6
01-Jun-20	174,023.8	(335.3)	(10,582.7)	163,105.8	(5.7)	163,100.1
01-Jun-21	174,713.0	0.0	(12,963.3)	161,749.7	(316.9)	161,432.8
01-Jun-22	150,465.2	0.0	(5,576.9)	144,888.3	(1,212.7)	143,675.6
01-Jun-23	150,143.9	0.0	(5,517.6)	144,626.3	(2,363.5)	142,262.8
01-Jun-24	154,362.5	0.0	(4,046.2)	150,316.3	(4,377.2)	145,939.1
01-Jun-25	137,733.6	0.0	(1,812.6)	135,921.0	(934.8)	134,986.2
01-Jun-26	137,803.1	0.0	(1,291.5)	136,511.6	0.0	136,511.6
01-Jun-27	134,478.1	0.0	0.0	134,478.1	0.0	134,478.1

Market Performance

Figure 5-8 shows cleared MW weighted average capacity market prices on a delivery year basis including base and incremental auctions for each delivery year, and the weighted average clearing prices by LDA in each Base Residual Auction for the entire history of the PJM capacity markets.

Table 5-21 shows RPM clearing prices for the 2021/2022 through 2027/2028 Delivery Years for all RPM auctions held through 2025, and Table 5-22 shows the RPM cleared MW for the 2021/2022 through 2027/2028 Delivery Years for all RPM auctions held through the first three months of 2026.

Figure 5-9 shows the RPM cleared MW weighted average prices for each LDA from the 2022/2023 Delivery Year to the current delivery year, and all results for auctions for future delivery years that have been held through the first three months of 2026. A summary of these weighted average prices is given in Table 5-23.

Table 5-24 shows RPM revenue by delivery year for all RPM auctions held through the first three months of 2026 based on the unforced MW cleared and the resource clearing prices. For the 2024/2025 Delivery Year, RPM revenue is $2.6 billion. For the 2025/2026 Delivery Year, RPM revenue is $14.9 billion.

Table 5-25 shows RPM revenue by calendar year for all RPM auctions held through 2025. In 2024, RPM revenue is $2.5 billion. In 2025, RPM revenue is $9.8 billion.

Table 5-26 shows the RPM annual charges to load. For the 2024/2025 Delivery Year, annual charges to load are $2.5 billion. For the 2025/2026 Delivery Year, annual charges to load are $14.8 billion.

Table 5-21 Capacity market clearing prices: 2021/2022 through 2027/2028 RPM Auctions

		RPM Clearing Price ($ per MW-day)														
	Product Type	RTO	MAAC	APS	PPL	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	PEPCO	ATSI	COMED	BGE	DUKE	DOM
2021/2022 BRA	Capacity Performance	$140.00	$140.00	$140.00	$140.00	$165.73	$140.00	$165.73	$204.29	$204.29	$140.00	$171.33	$195.55	$200.30	$140.00	$140.00
2021/2022 First Incremental Auction	Capacity Performance	$23.00	$23.00	$23.00	$23.00	$25.00	$23.00	$25.00	$45.00	$219.00	$23.00	$23.00	$23.00	$60.00	$23.00	$23.00
2021/2022 Second Incremental Auction	Capacity Performance	$10.26	$10.26	$10.26	$10.26	$15.37	$10.26	$15.37	$125.00	$125.00	$10.26	$10.26	$10.26	$70.00	$10.26	$10.26
2021/2022 Third Incremental Auction	Capacity Performance	$20.55	$20.55	$20.55	$20.55	$26.36	$20.55	$26.36	$31.00	$31.00	$20.55	$20.55	$20.55	$39.00	$20.55	$20.55
2022/2023 BRA	Capacity Performance	$50.00	$95.79	$50.00	$95.79	$97.86	$95.79	$97.86	$97.86	$97.86	$95.79	$50.00	$68.96	$126.50	$71.69	$50.00
2022/2023 Third Incremental Auction	Capacity Performance	$19.00	$35.00	$19.00	$35.00	$35.00	$96.15	$35.00	$35.00	$35.00	$35.00	$19.00	$19.00	$35.00	$19.00	$19.00
2023/2024 BRA	Capacity Performance	$34.13	$49.49	$34.13	$49.49	$49.49	$49.49	$69.95	$49.49	$49.49	$49.49	$34.13	$34.13	$69.95	$34.13	$34.13
2023/2024 Third Incremental Auction	Capacity Performance	$37.53	$49.49	$37.53	$49.49	$146.03	$49.49	$146.03	$146.03	$146.03	$49.49	$37.53	$37.53	$79.03	$37.53	$37.53
2024/2025 BRA	Capacity Performance	$28.92	$49.49	$28.92	$49.49	$53.60	$49.49	$426.17	$53.60	$53.60	$49.49	$28.92	$28.92	$73.00	$96.24	$28.92
2024/2025 Third Incremental Auction	Capacity Performance	$58.00	$80.00	$58.00	$80.00	$175.81	$80.00	$175.81	$175.81	$175.81	$80.00	$58.00	$58.00	$155.29	$58.00	$58.00
2025/2026 BRA	Capacity Performance	$269.92	$269.92	$269.92	$269.92	$269.92	$269.92	$269.92	$269.92	$269.92	$269.92	$269.92	$269.92	$466.35	$269.92	$444.26
2025/2026 Third Incremental Auction	Capacity Performance	$323.90	$323.90	$323.90	$323.90	$323.90	$323.90	$323.90	$323.90	$323.90	$323.90	$323.90	$323.90	$559.64	$323.90	$323.90
2026/2027 BRA	Capacity Performance	$329.17	$329.17	$329.17	$329.17	$329.17	$329.17	$329.17	$329.17	$329.17	$329.17	$329.17	$329.17	$329.17	$329.17	$329.17
2026/2027 Third Incremental Auction	Capacity Performance	$164.70	$164.70	$164.70	$164.70	$164.70	$164.70	$164.70	$164.70	$164.70	$164.70	$164.70	$164.70	$164.70	$164.70	$164.70
2027/2028 BRA	Capacity Performance	$333.44	$333.44	$333.44	$333.44	$333.44	$333.44	$333.44	$333.44	$333.44	$333.44	$333.44	$333.44	$333.44	$333.44	$333.44

Table 5-22 Capacity market cleared MW: 2021/2022 through 2027/2028 RPM Auctions[174]

		UCAP (MW)														
Delivery Year	Auction	RTO	MAAC	APS	PPL	EMAAC	DPL South	PSEG	PSEG North	PEPCO	ATSI	COMED	BGE	DUKE	DOM	TOTAL
2021/2022	BASE	26,552.8	12,565.1	10,136.1	15,368.6	22,286.8	1,673.8	2,237.7	3,134.1	6,013.2	8,010.5	22,358.1	4,200.7	2,746.1	26,343.7	163,627.3
2021/2022	FIRST	118.7	200.4	45.9	27.2	119.0	15.3	18.3	79.1	207.9	739.3	360.4	48.7	87.6	75.4	2,143.2
2021/2022	SECOND	1,082.0	335.8	30.3	55.4	129.9	39.3	97.0	98.1	75.7	1,216.8	205.9	115.5	65.3	160.5	3,707.5
2021/2022	THIRD	1,243.7	168.7	231.6	127.8	911.0	18.3	227.7	244.8	67.2	942.7	221.7	275.9	159.2	394.7	5,235.0
2022/2023	BASE	29,596.0	12,804.7	10,147.4	14,118.7	23,651.2	1,312.9	1,914.3	2,531.1	3,621.8	10,550.7	19,223.7	4,750.9	2,117.7	8,136.3	144,477.3
2022/2023	THIRD	703.3	338.9	84.2	105.7	572.2	9.4	244.3	402.0	27.4	358.0	2,292.3	409.7	44.8	395.7	5,987.9
2023/2024	BASE	28,642.1	10,098.5	8,145.5	14,352.7	22,912.6	1,412.8	2,497.1	3,344.9	3,521.8	9,535.9	25,368.9	5,001.0	1,966.4	8,266.7	145,066.9
2023/2024	THIRD	255.9	1,786.4	395.0	79.3	671.0	24.2	32.4	43.8	15.3	355.8	1,050.0	240.0	68.4	59.8	5,077.0
2024/2025	BASE	28,760.7	10,854.4	8,874.0	14,178.1	23,135.1	1,448.6	2,665.3	3,494.3	3,429.7	9,720.6	25,156.1	5,056.5	2,062.1	8,646.1	147,481.5
2024/2025	THIRD	365.3	744.8	815.6	665.2	963.0	33.2	48.7	60.2	78.7	245.6	2,370.0	222.5	90.2	177.9	6,881.0
2025/2026	BRA	24,573.1	9,490.1	8,481.3	12,368.8	19,043.0	958.7	1,894.3	2,520.1	2,274.4	7,778.5	21,814.2	2,800.6	1,636.7	20,050.2	135,684.0
2025/2026	THIRD	731.3	22.2	90.8	31.9	564.8	26.1	9.0	34.7	79.4	177.2	91.5	8.3	19.8	162.7	2,049.6
2026/2027	BRA	24,888.5	9,213.7	8,476.5	11,939.7	18,861.0	998.0	1,725.3	2,361.6	2,170.2	7,433.9	20,273.0	4,319.1	1,560.1	19,984.8	134,205.3
2026/2027	THIRD	743.4	197.4	149.4	332.3	247.8	31.9	62.4	75.0	98.6	298.3	544.6	89.9	84.9	641.9	3,597.8
2027/2028	BRA	24,711.5	9,147.3	8,542.9	12,146.5	18,754.7	959.6	1,777.6	2,379.7	2,222.2	7,603.6	19,567.1	4,334.2	2,416.6	19,914.6	134,478.1

174 The MW values in this table refer to rest of LDA or RTO values, which are net of nested LDA values.

Table 5-23 Weighted average clearing prices by zone: 2024/2025 through 2027/2028

	Weighted Average Clearing Price ($ per MW-day)			
LDA	2024/2025	2025/2026	2026/2027	2027/2028
RTO				
AEP	$29.80	$270.57	$324.96	$333.44
APS	$29.80	$270.57	$324.96	$333.44
ATSI	$29.80	$271.18	$321.98	$333.44
Cleveland	$28.92	$270.90	$325.95	$333.44
COMED	$31.42	$270.15	$324.87	$333.44
DAY	$29.13	$295.05	$322.41	$333.44
DUKE	$94.57	$270.57	$320.68	$333.44
DUQ	$29.80	$270.57	$324.96	$333.44
DOM	$29.80	$443.29	$324.05	$333.44
EKPC	$29.80	$270.57	$324.96	$333.44
MAAC				
EMAAC				
ACEC	$58.47	$271.47	$327.72	$333.44
DPL	$58.47	$271.47	$327.72	$333.44
DPL South	$420.55	$271.35	$324.08	$333.44
JCPLC	$58.47	$271.47	$322.79	$333.44
PECO	$58.47	$271.47	$327.72	$333.44
PSEG	$55.54	$270.17	$323.43	$333.44
PSEG North	$55.48	$270.65	$324.11	$333.44
REC	$58.47	$271.47	$327.72	$333.44
SWMAAC				
BGE	$77.88	$466.64	$324.89	$333.44
PEPCO	$50.12	$271.74	$322.02	$333.44
WMAAC				
MEC	$51.07	$270.01	$326.00	$333.44
PE	$51.07	$270.01	$326.00	$333.44
PPL	$51.18	$270.12	$323.88	$333.44

Table 5-24 RPM revenue by delivery year: 2007/2008 through 2027/2028[175]

Delivery Year	Weighted Average RPM Price ($ per MW-day)	Weighted Average Cleared UCAP (MW)	Days	RPM Revenue
2007/2008	$89.78	129,409.2	366	$4,252,287,381
2008/2009	$127.67	130,629.8	365	$6,087,147,586
2009/2010	$153.37	134,030.2	365	$7,503,218,157
2010/2011	$172.71	134,036.2	365	$8,449,652,496
2011/2012	$108.63	134,182.6	366	$5,335,087,023
2012/2013	$75.08	141,283.9	365	$3,871,714,635
2013/2014	$116.55	159,844.5	365	$6,799,778,047
2014/2015	$126.40	161,205.0	365	$7,437,267,646
2015/2016	$160.01	173,519.4	366	$10,161,726,902
2016/2017	$121.84	179,749.0	365	$7,993,888,695
2017/2018	$141.19	180,590.5	365	$9,306,676,719
2018/2019	$172.09	175,996.0	365	$11,054,943,851
2019/2020	$109.82	177,064.2	366	$7,116,815,360
2020/2021	$111.07	173,688.5	365	$7,041,524,517
2021/2022	$147.33	174,713.0	365	$9,395,567,946
2022/2023	$72.33	150,465.2	365	$3,972,428,671
2023/2024	$42.01	150,143.9	366	$2,308,670,914
2024/2025	$45.57	154,362.5	365	$2,567,491,013
2025/2026	$296.98	137,733.6	365	$14,930,072,430
2026/2027	$324.88	137,803.1	365	$16,340,680,278
2027/2028	$333.44	134,478.1	366	$16,411,578,225

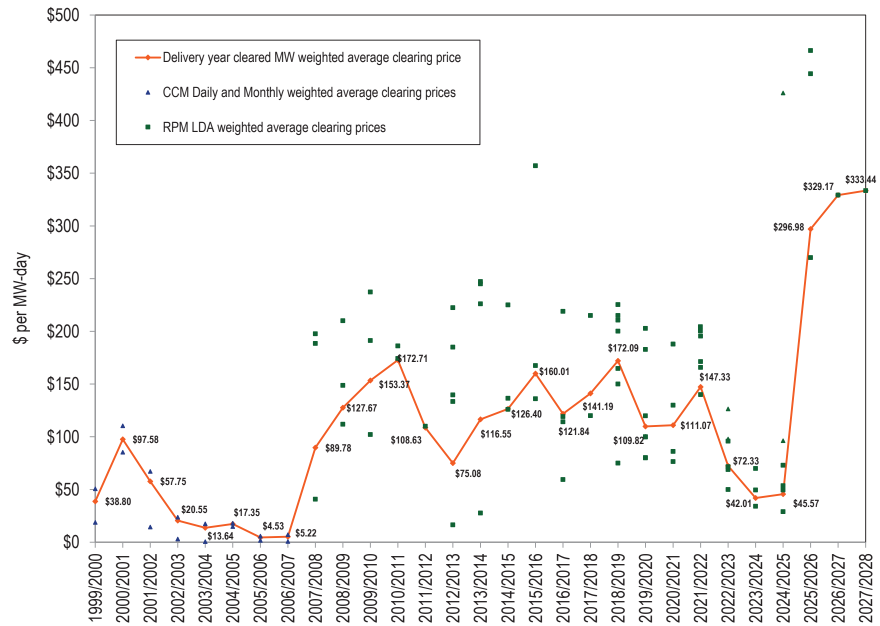
175 The results for the ATSI Integration Auctions are not included in this table.

Table 5-25 RPM revenue by calendar year: 2007 through 2028[176]

Year	Weighted Average RPM Price ($ per MW-day)	Weighted Average Cleared UCAP (MW)	Effective Days	RPM Revenue
2007	$89.78	75,665.5	214	$2,486,310,108
2008	$111.93	130,332.1	366	$5,334,880,241
2009	$142.74	132,623.5	365	$6,917,391,702
2010	$164.71	134,033.7	365	$8,058,113,907
2011	$135.14	133,907.1	365	$6,615,032,130
2012	$89.01	138,561.1	366	$4,485,656,150
2013	$99.39	152,166.0	365	$5,588,442,225
2014	$122.32	160,642.2	365	$7,173,539,072
2015	$146.10	168,147.0	365	$9,018,343,604
2016	$137.69	177,449.8	366	$8,906,998,628
2017	$133.19	180,242.4	365	$8,763,578,112
2018	$159.31	177,896.7	365	$10,331,688,133
2019	$135.58	176,338.6	365	$8,734,613,179
2020	$110.55	175,368.7	366	$7,084,072,778
2021	$132.33	174,289.2	365	$8,421,703,404
2022	$103.36	160,496.5	365	$6,215,973,960
2023	$54.56	150,036.3	365	$2,993,266,921
2024	$44.09	152,857.8	366	$2,464,115,790
2025	$192.97	144,613.0	365	$9,815,689,432
2026	$313.34	137,774.3	365	$15,757,113,743
2027	$329.90	135,638.2	365	$16,355,957,867
2028	$333.44	55,848.8	152	$6,815,737,405

176 The results for the ATSI Integration Auctions are not included in this table.

Figure 5-8 History of capacity prices: 1999/2000 through 2027/2028[177]



177 The 1999/2000 through 2006/2007 capacity prices are CCM combined market, weighted average prices. The 2007/2008 through 2027/2028 capacity prices are RPM weighted average prices. The CCM data points plotted are cleared MW weighted average prices for the daily and monthly markets by delivery year. The RPM data points plotted are RPM LDA clearing prices. For the 2014/2015 and subsequent delivery years, only the prices for Annual Resources or Capacity Performance Resources are plotted.

Figure 5-9 Map of RPM capacity prices: 2024/2025 through 2027/2028

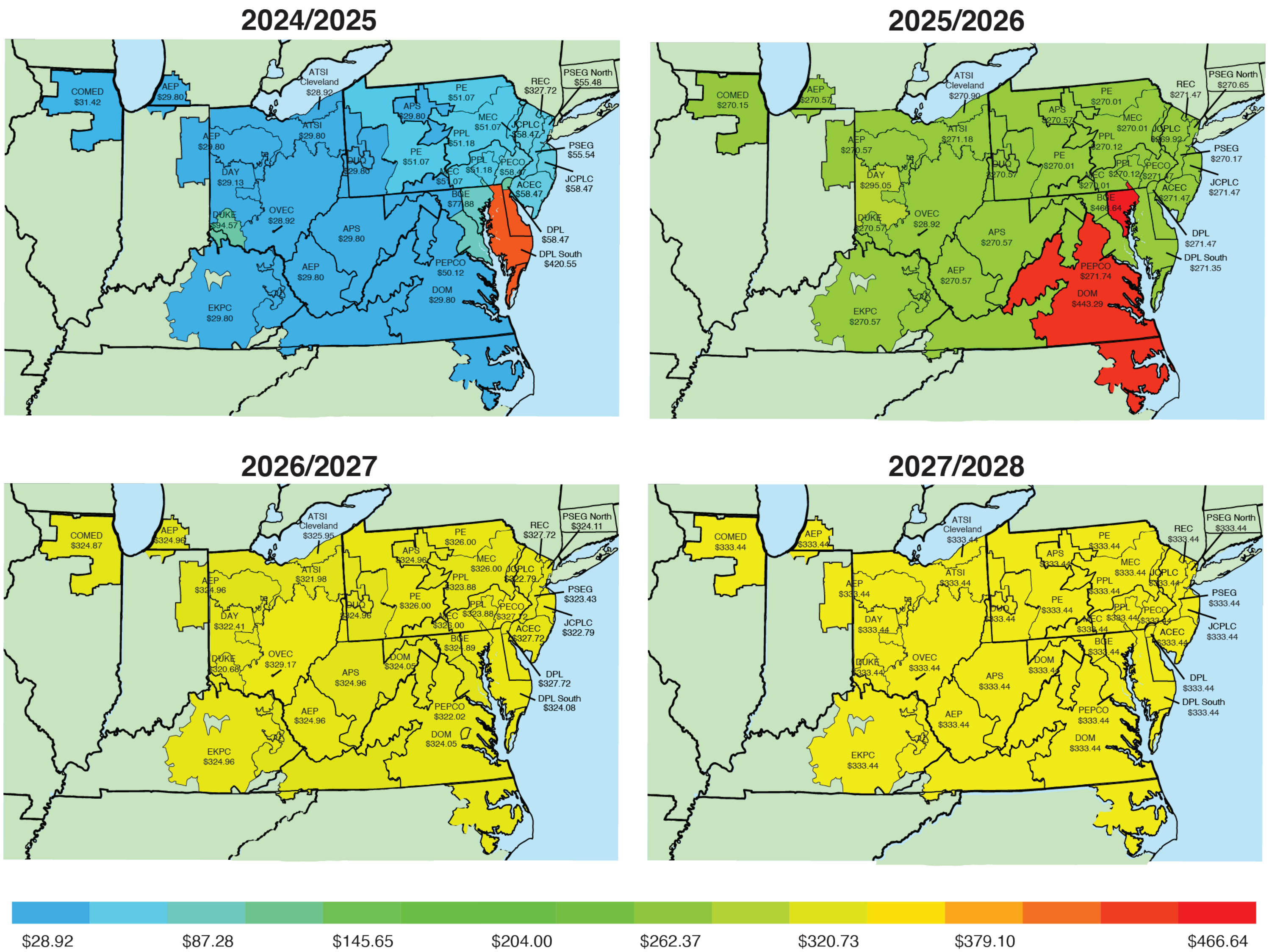


Table 5-26 RPM cost to load: 2021/2022 through 2027/2028 RPM Auctions[178 179]

	Net Load Price ($ per MW-day)	UCAP Obligation (MW)	Annual Charges
2021/2022			
Rest of RTO	$142.16	82,768.3	$4,294,838,410
Rest of EMAAC	$164.73	23,719.9	$1,426,178,211
ATSI	$160.21	13,995.4	$818,411,597
BGE	$163.50	7,491.2	$447,049,048
COMED	$198.43	22,721.2	$1,645,630,168
PSEG	$188.46	10,987.4	$755,803,998
Total		161,683.4	$9,387,911,433
2022/2023			
Rest of RTO	$50.05	50,750.7	$927,101,691
EMAAC	$97.93	35,388.1	$1,264,867,389
WMAAC	$96.61	15,072.2	$531,498,382
BGE	$108.22	7,457.7	$294,575,131
COMED	$66.23	24,064.5	$581,774,443
DEOK	$59.75	5,090.6	$111,011,442
PEPCO	$96.15	6,870.5	$241,111,291
Total		144,694.3	$3,951,939,768
2023/2024			
Rest of RTO	$34.18	78,896.5	$986,982,057
EMAAC	$50.96	30,972.7	$577,657,195
WMAAC	$49.58	22,401.9	$406,535,572
Rest of EMAAC	$57.19	4,375.0	$91,582,753
BGE	$59.38	7,496.6	$162,936,916
Total		144,142.8	$2,225,694,492
2024/2025			
Rest of RTO	$29.50	77,398.7	$833,520,097
EMAAC	$56.56	32,270.3	$666,184,144
WMAAC	$50.22	22,872.2	$419,263,035
Rest of EMAAC	$175.22	4,590.0	$293,561,344
BGE	$61.53	7,726.0	$173,527,700
DEOK	$57.93	5,254.4	$111,105,639
Total		150,111.7	$2,497,161,960
2025/2026			
Rest of RTO	$270.43	108,328.9	$10,692,932,080
BGE	$306.84	6,005.7	$672,628,585
DOM	$432.48	21,570.5	$3,405,010,751
Total		135,905.1	$14,770,571,416
2026/2027			
Rest of RTO	$329.08	134,490.7	$16,154,098,654
Total		134,490.7	$16,154,098,654
2027/2028			
Rest of RTO	$333.69	134,478.1	$16,379,008,974
Total		134,478.1	$16,379,008,974

178 The RPM annual charges are calculated using the rounded, net load prices as posted in the PJM RPM auction results.
179 There is no separate obligation for DPL South as the DPL South LDA is completely contained within the DPL Zone. There is no separate obligation for PSEG North as the PSEG North LDA is completely contained within the PSEG Zone. There is no separate obligation for ATSI Cleveland as the ATSI Cleveland LDA is completely contained within the ATSI Zone.

FRR

The states have authority over their generation resources and can choose to remain in PJM capacity markets or to create FRR entities. The existing FRR approach remains an option for utilities with regulated revenues based on cost of service rates, including both privately and publicly owned (including public power entities and electric cooperatives) utilities. Such regulated utilities have had and continue to have the ability to opt out of the capacity market and provide their own capacity. The existing FRR rules were created in 2007 primarily for the specific circumstances of AEP as part of the original RPM capacity market design settlement. The MMU recommends that the FRR rules 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.

The MMU has prepared reports with analysis of the potential impacts on states pursuing the FRR option. In separate reports for Illinois, Maryland, New Jersey, Ohio, Virginia, and the District of Columbia, the cost impacts of the state choosing the FRR option are computed under different FRR capacity price assumptions and different assumptions regarding the composition of the FRR service area.[180 181 182 183 184 185] The reports showed that the FRR approach is likely to lead to significant increases in payments by customers if it were to replace participation in the PJM markets. The impact on the remaining PJM capacity market footprint is also computed for each scenario. In all but a few scenarios the MMU finds that the FRR leads to higher costs for load included in the FRR service area. In all scenarios the MMU finds that prices in what remains of the PJM Capacity Market would be significantly lower.

180 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of a ComEd FRR," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Potential_Impacts_of_the_Creation_of_a_ComEd_FRR_20191218.pdf> (December 18, 2020).
181 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of Maryland FRRs," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_Maryland_FRRs_20200416.pdf> (April 16, 2020).
182 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of New Jersey FRRs," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_New_Jersey_FRRS_20200513.pdf> (May 13, 2020).
183 *In the Matter of the Investigation of Resource Adequacy Alternatives*, New Jersey Board of Public Utilities, Docket No. EO20030203. Monitoring Analytics, LLC Comments, <http://www.monitoringanalytics.com/filings/2020/IMM_Comments_Docket_No_EO20030203_20200520.pdf> (May 20, 2020). Monitoring Analytics, LLC, Reply Comments <http://www.monitoringanalytics.com/filings/2020/IMM_Reply_Comments_Docket_No_EO20030203_20200624.pdf>. (June 24, 2020). Monitoring Analytics, Answer to Exelon and PSEG, <http://www.monitoringanalytics.com/filings/2020/IMM_Answer_to_Exelon_PSEG_Docket_No_EO20030203_20200715.pdf> (July 15, 2020).
184 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of Ohio FRRs," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of%20Ohio_FRRs_20200717.pdf> (July 17, 2020).
185 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of Virginia FRRs," <https://www.monitoringanalytics.com/reports/Reports/2021/IMM_VA_FRR_Report_20210518.pdf> (May 18, 2021).

Both FERC and the states have significant and overlapping authority affecting wholesale power markets. While the FERC MOPR approach was designed to ensure that subsidies did not affect the wholesale power markets, the states have ultimate authority over the generation choices made in the states. The FRR explorations by multiple states illustrated a possible path forward. Under that path, the FERC regulated markets would be unaffected by subsidies but many states would withdraw from the FERC regulated markets and create higher cost nonmarket solutions rather than be limited by MOPR. That would not be an efficient outcome and would not serve the interests of customers or generators.

With the elimination of the prior MOPR rules, the capacity market design must accommodate the choices made by states to subsidize renewable resources in a way that maximizes the role of competition to ensure that customers pay the lowest amount possible, consistent with state goals and the costs of providing the desired resources. Such an approach can take several forms, but none require the dismantling of the PJM capacity market design. The PJM capacity market design can adapt to a wide range of state supported resources and state programs. As a simple starting point, states can continue to support selected resources using a range of payment structures and those resources could participate in the capacity auctions. As a broader and more comprehensive option, PJM could create a central PJM RECs market to facilitate the competitive sale and purchase of RECs.

Dominion Energy Virginia elected the FRR option for the 2022/2023 through 2024/2025 delivery years but returned to the capacity market for the 2025/2026 BRA.

CRF Issue[186]

As a result of the significant changes to the federal tax code in December 2017, the capital recovery factor (CRF) tables in PJM OATT Attachment DD § 6.8(a) and Schedule 6A were not correct.[187] These tables should have been updated in 2018. Correct CRFs ensure that offer caps and offer floors in the capacity market are correct. On May 4, 2021, PJM filed updates to the OATT under FPA Section 205.[188] In the filing, PJM proposed new CRFs based on the new tax law and new financial assumptions. The new financial assumptions are identical to the assumptions used in the PJM quadrennial review for the calculation of the cost of new entry (CONE) for the PJM reference resource. The MMU, in comments to the Commission, asked that the following formula be included in the tariff as an efficient alternative to use of tables which require updates whenever tax laws or financial assumptions change:[189] [190]

The MMU also proposed that PJM discontinue the practice of using an average state tax rate in the CRF calculation. The CRF formula allows for the quick and efficient calculation of a unit's CRF using the state tax rate that is applicable to a specific unit.

FERC accepted PJM's filing but also required that the MMU's CRF formula be included in the tariff.[191] FERC rejected the MMU's unit specific state tax recommendation. Going forward, PJM will post the CRFs on their website. Table 5-28 shows the CRFs that are currently posted. The values in Table 5-28 were calculated using the formula above and the financial assumptions in Table 5-29. Bonus depreciation assumptions vary by delivery year with 100 percent bonus depreciation assumed in the 2022/2023 Delivery Year. Under the TCJA, the bonus depreciation in each subsequent delivery year is reduced by 20 percent.

Table 5-27 Variable descriptions for the CRF formula

Formula Symbol	Description
r	After tax weighted average cost of capital (ATWACC)
s	Effective tax rate
B	Bonus depreciation percent
N	Cost Recovery Period (years)
L	Lesser of N or 16 (years)
mj	Modified Accelerated Cost Recovery System (MACRS) depreciation factor for year j = 1, ..., 16

186 See related filing on CRF issue in black start: Comments of the Independent Market Monitor for PJM, Docket No. ER21-1635 (April 28, 2021).
187 The federal tax code was changed in the Tax Cuts and Jobs Act or TCJA.
188 "Revisions to Capital Recovery Factor for Avoidable Project Investment Cost Determinations and Request for Waiver of Sixty-Day Notice Requirement," PJM Interconnection L.L.C., Docket No. ER21-1844-000 (May 4, 2021).
189 See "Comments of the Independent Market Monitor for PJM," Docket No. ER21-1844-000 (May 25, 2021).
190 The formula was first introduced in a related Section 205 filing regarding CRFs for black start service. See "Comments of the Independent Market Monitor for PJM" (April 28, 2021) and "Answer and Motion to Answer of the Independent Market Monitor for PJM" (May 19, 2021) in Docket No. ER21-1635-000.
191 176 FERC ¶61,003 (2021).

On July 4, 2025, with the enactment of the One Big Beautiful Bill Act ("OBBBA"), the bonus depreciation rules changed again. Section 70301 of OBBBA (I.R.C. § 168(k)) allows 100 percent bonus depreciation for "qualified production property ("QPP") acquired and placed in service on or after January 20, 2025.[192] QPP means nonresidential real property used in manufacturing, production, or refining of tangible personal property in the United States.[193] QPP includes power production facilities. To be eligible, construction must begin after January 19, 2025, and before January 1, 2029, and the property must be placed in service before January 1, 2031.[194] Table 5-28 shows the CRF values produced by the CRF formula using the parameter assumptions in Table 5-29. The effect of the change in bonus depreciation rules from the OBBBA is reflected in the CRF for 2027/2028 Third IA. The CRF value for the five year recovery period decreases from 0.314 to 0.249, a 20.7 percent decrease.

Table 5-28 Levelized CRF values: Delivery Year 2023/2024 through Delivery Year 2028/2029

Age of Unit (Years)	Cost Recovery Period	2023/2024	2024/2025	2025/2026	2026/2027	2027/2028 BRA	2027/2028 3rd IA	2028/2029
		Bonus Depreciation Percent						
		80%	60%	40%	20%	0%	100%	100%
1 to 5	30	0.091	0.094	0.096	0.105	0.107	0.093	0.099
6 to 10	25	0.096	0.098	0.101	0.110	0.113	0.098	0.103
11 to 15	20	0.104	0.107	0.110	0.118	0.121	0.105	0.110
16 to 20	15	0.119	0.122	0.126	0.134	0.138	0.120	0.124
21 to 25	10	0.152	0.158	0.164	0.174	0.180	0.151	0.155
25 Plus	5	0.258	0.271	0.283	0.301	0.314	0.249	0.253
Mandatory CapEx	4	0.312	0.328	0.345	0.367	0.383	0.300	0.303
40 Plus Alternative	1	1.100	1.100	1.100	1.100	1.100	1.100	1.100

Table 5-29 Financial parameter and tax rate assumptions for CRF calculations

	Parameter Values			
Parameter	Prior to 2026/2027	2026/2027	2027/2028	2028/2029
Equity Funding Percent	45.000%	45.000%	45.000%	45.000%
Debt Funding Percent	55.000%	55.000%	55.000%	55.000%
Equity Rate	13.000%	14.100%	14.100%	16.000%
Debt Interest Rate	6.000%	6.300%	6.300%	5.800%
Federal Income Tax Rate	21.000%	21.000%	21.000%	21.000%
State Income Tax Rate	9.300%	9.933%	9.933%	8.500%
Effective Income Tax Rate	28.347%	28.847%	28.847%	27.715%
After Tax Weighted Average Cost of Capital	8.215%	8.810%	8.810%	9.506%

The 2021 update to the CRF values was calculated using the weighted average cost of capital (WACC) model. The original CRF values, prior to 2021, were calculated using a flow to equity (FTE) model. The WACC model assumes a constant debt to equity ratio during the capital recovery period and therefore assumes that debt holders are paid more quickly than is required. The FTE model recognizes that the debt is repaid according to a predetermined payment schedule with all revenue in excess of taxes and debt payments going to the equity investor. The FTE model accurately reflects the cash flows that occur during capital recovery. Table 5-30 compares CRFs calculated under the two approaches using the assumptions in Table 5-29. The difference between the WACC CRF and FTE CRF is dependent upon the capital recovery term and the level of bonus depreciation. The WACC CRF exceeds the FTE CRF by 16.4 percent under 100 percent bonus depreciation with a 30 year cost recovery term. The FTE model is the correct approach because it accurately captures the cash flows during capital recovery over the defined financial life of the asset.

192 OBBBA § 70301(c)(1).
193 OBBBA § 70307(a)(2).
194 *Id.*

Table 5-30 Comparison of FTE and WACC CRFs

Capital Recovery Term (years)	WACC CRF						FTE CRF					
	Bonus Percent						Bonus Percent					
	100%	80%	60%	40%	20%	0%	100%	80%	60%	40%	20%	0%
4	0.32	0.312	0.328	0.345	0.361	0.377	0.289	0.307	0.324	0.342	0.360	0.377
5	0.246	0.258	0.271	0.283	0.296	0.308	0.238	0.252	0.266	0.280	0.294	0.308
10	0.147	0.152	0.158	0.164	0.169	0.175	0.138	0.145	0.153	0.160	0.168	0.175
15	0.116	0.119	0.122	0.126	0.129	0.132	0.105	0.111	0.116	0.122	0.127	0.133
20	0.101	0.104	0.107	0.110	0.113	0.115	0.090	0.095	0.100	0.105	0.110	0.115
25	0.093	0.096	0.098	0.101	0.104	0.106	0.081	0.086	0.091	0.096	0.100	0.105
30	0.088	0.091	0.094	0.096	0.099	0.101	0.076	0.081	0.085	0.090	0.095	0.099
Capital Recovery Term (years)	Absolute Change (WACC CRF less FTE CRF)						Relative Change					
	Bonus Percent						Bonus Percent					
	100%	80%	60%	40%	20%	0%	100%	80%	60%	40%	20%	0%
4	0.007	0.005	0.004	0.003	0.001	0.000	2.3%	1.8%	1.2%	0.8%	0.3%	(0.1%)
5	0.007	0.006	0.004	0.003	0.001	0.000	3.1%	2.3%	1.6%	1.0%	0.4%	(0.1%)
10	0.009	0.007	0.005	0.003	0.002	0.000	6.5%	4.9%	3.4%	2.1%	0.9%	(0.2%)
15	0.010	0.008	0.006	0.004	0.002	0.000	9.5%	7.2%	5.0%	3.1%	1.3%	(0.3%)
20	0.011	0.009	0.007	0.005	0.003	0.000	12.2%	9.3%	6.7%	4.4%	2.3%	0.4%
25	0.012	0.010	0.007	0.005	0.003	0.001	14.4%	11.2%	8.2%	5.6%	3.2%	1.1%
30	0.012	0.010	0.008	0.006	0.004	0.002	16.4%	12.8%	9.6%	6.7%	4.1%	1.7%

Timing of Unit Retirements

Generation owners that want to deactivate a unit, either to mothball or permanently retire, must provide notice to PJM and the MMU prior to the proposed deactivation date. Prior to September 2022, generation owners were required to provide deactivation notices at least 90 days before the proposed deactivation date. Beginning in September 2022, PJM and the MMU began reviewing deactivation requests quarterly, and the desired deactivation date is now based on the quarter the request was submitted (Table 5-31). The result is no change to the effective period between the notice and the retirement if notice is provided on the last day of the submittal period, and an increase to six months notice, if notice is given on the first day of the submittal period. The MMU recommends that participants be required to provide a notice of deactivation 12 months prior to an auction in which the unit will not be offered due to the deactivation; and no less than 12 months prior to the date of deactivation.

Table 5-31 Earliest deactivation dates allowed based on quarterly submission

Date Request Submitted	Earliest Deactivation Date Permitted
January 1 to March 31	July 1
April 1 to June 30	October 1
July 1 to September 30	January 1 (following calendar year)
October 1 to December 31	April 1 (following calendar year)

Generation owners seeking a capacity market must offer exemption for a delivery year must submit their deactivation request no later than the December 1 preceding the Base Residual Auction or 120 days before the start of an Incremental Auction for that delivery year.[195] If no reliability issues are found during PJM's analysis of the retirement's impact on the transmission system, and the MMU finds no market power issues associated with the proposed deactivation, the unit may deactivate at any time thereafter.[196]

Table 5-32 shows the timing of actual deactivation dates and the initially requested deactivation date, for all deactivation requests submitted from January 2018 through March 2026. Of the 234 deactivation requests submitted, 33 units (14.1 percent) deactivated an average of 158 days earlier than their initially requested date; 34 units (14.5 percent) deactivated an average of 120 days later than the originally requested deactivation date; and 89 units (38.0 percent) deactivated on their initially requested date. Thirty eight (16.2 percent) of the unit deactivations were cancelled an average of 285 days (approximately 41 weeks) before their scheduled deactivation date, and 40 (17.1 percent) of the unit deactivations have not yet reached their target retirement date. Table 5-33 shows this information broken out by fuel types.

Due to the significant increase in the capacity price for the 2025/2026 Delivery Year, several units that were scheduled to deactivate rescinded their deactivation request. In 2024, Middle River Power, LLC, rescinded the deactivation of 483 MW from the Elgin CT 1-4 units. In 2025, 18 other units that were slated to deactivate (216 MW from Gen On Energy Management, LLC rescinding Morgantown CT 3-6; 54.9 MW from Constellation Energy Co. rescinding Perryman 6 unit 1; 15 MW from Tenaska Power Services, Co. rescinding Kenilworth; 272.1 MW from NRG Business Marketing LLC

195 OATT Attachment DD § 6.6(g).
196 OATT Part V §113.

rescinding Fisk CT 31- 34 and Waukegan CT 31 & 32; 223.0 MW from Heritage Power, LLC rescinding Sayreville CT 1-4; 31.0 MW from Forked River Power, LLC rescinding Forked River 2), accounting for 812.0 MW, rescinded their deactivation requests.

Table 5-32 Timing of actual unit deactivations compared to requested deactivation date: Requests submitted January 2018 through March 2026[197]

Status	Number of Units	Percent	Average Days Deviation from Originally Requested Date
Early	33	14.1%	(158)
Late	34	14.5%	120
On time	89	38.0%	0
Cancelled	38	16.2%	(285)
Pending	40	17.1%	-
Total	234	100.0%	-

197 Negative values indicate the average number of days the action is taken prior to the requested date.

Table 5-33 Timing of actual unit deactivations compared to requested deactivation date by fuel type: Requests submitted January 2018 through March 2026

Fuel Type	Status	Number of Units	Percent	Average Days Deviation from Originally Requested Date
Biomass	Early	2	40.0%	(4)
	Late	1	20.0%	14
	On time	2	40.0%	-
	Cancelled	0	0.0%	-
	Pending	0	0.0%	-
	Total	5	100.0%	-
Coal	Early	15	28.3%	(169)
	Late	10	18.9%	170
	On time	16	30.2%	0
	Cancelled	4	7.5%	(371)
	Pending	8	15.1%	-
	Total	53	100.0%	-
Diesel	Early	0	0.0%	-
	Late	0	0.0%	-
	On time	7	100.0%	0
	Cancelled	0	0.0%	-
	Pending	0	0.0%	-
	Total	7	100.0%	-
Methane	Early	5	17.9%	(92)
	Late	7	25.0%	71
	On time	11	39.3%	0
	Cancelled	2	7.1%	(190)
	Pending	3	10.7%	-
	Total	28	100.0%	-
Natural Gas	Early	4	6.9%	(197)
	Late	8	13.8%	71
	On time	20	34.5%	0
	Cancelled	8	13.8%	(220)
	Pending	18	31.0%	-
	Total	58	100.0%	-
Nuclear	Early	0	0.0%	-
	Late	0	0.0%	-
	On time	0	0.0%	-
	Cancelled	10	100.0%	(312)
	Pending	0	0.0%	-
	Total	10	100.0%	-
Oil	Early	3	5.8%	(218)
	Late	7	13.5%	188
	On time	24	46.2%	0
	Cancelled	13	25.0%	(317)
	Pending	5	9.6%	-
	Total	52	100.0%	-
Solar	Early	0	0.0%	-
	Late	0	0.0%	-
	On time	1	1.9%	0
	Cancelled	0	0.0%	-
	Pending	0	0.0%	-
	Total	1	1.9%	-
Solid Waste	Early	0	0.0%	-
	Late	0	0.0%	-
	On time	1	100.0%	0
	Cancelled	0	0.0%	-
	Pending	0	0.0%	-
	Total	1	100.0%	-
Storage	Early	4	21.1%	(194)
	Late	1	5.3%	-
	On time	7	36.8%	0
	Cancelled	1	5.3%	-
	Pending	6	31.6%	-
	Total	19	100.0%	-

Part V Reliability Service (RMR)

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.[198] This provision has been known as Reliability Must Run (RMR) service but RMR is not defined in the PJM tariff, and the PJM market design has important distinguishing features relative to other regions where arrangements referred to as RMR are used. Here the term Part V reliability service is used. The need to retain uneconomic units in service reflects a flawed market design and/or planning process problems. The current capacity market design fails to include transmission constraints inside LDAs with the result that units needed for reliability do not clear in capacity auctions and that prices are suppressed and an RMR is then required. The current approach does not adequately look forward and attempt to address foreseeable unit retirements, whether for economic or regulatory reasons. The result is the wrong price signal for either investing in the existing resource or investing in new resources to provide locational reliability. The answer is not to artificially increase prices during the RMR while the transmission alternative is under construction but to provide an actionable price signal in advance of retirement as a signal to new generation to enter and compete with the transmission solution. It is essential that the deactivation provisions of the tariff be evaluated and modified, both to provide rules that better anticipate deactivations in the markets and rules that reasonably compensate Part V reliability service if it is still needed. Recent changes to the rules fail to address these issues.[199] It is also essential that queue processes that effectively prevent competition from new generation to replace the old generation be modified.

To improve coordination of deactivations and PJM transmission system planning, the MMU recommends that the same reliability standard be used in capacity auctions as is used by PJM transmission planning which means recognizing transmission constraints inside LDAs when they create reliability issues. 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. This result indicates a significant market design flaw.

198 OATT Part V §114.

199 See Deactivation Enhancements Senior Task Force (DESTF), which can be accessed at: <*https://www.pjm.com/committees-and-groups/task-forces/destf*> .

The MMU recommends that PJM treat the inclusion of RMR resources in the capacity market consistently. PJM currently includes RMR units in the reliability analysis for RPM auctions but does not include the RMR units in the supply curves. This approach is internally inconsistent. It would be internally consistent to leave the RMR units out of the CETO/CETL analysis. It would also be internally consistent to include the RMR units in the supply of capacity and in the CETO/CETL analysis. Including RMR resources in the capacity supply curve does not mean forcing unit owners to offer or to take on PAI risk, for example. It simply means that PJM would recognize the fact that PJM treats RMR resources as a source of reliability. The goal is to ensure that the underlying supply and demand fundamentals are included in the capacity market prices. These two options have very different implications for capacity market prices. There are times early in the process when a price signal for the entry of generation is appropriate, e.g. when the goal is to allow generation to compete to replace the transmission option, in whole or in part, and there is enough time to permit such new entry. There are times later in the process when a price signal for the entry of generation is not needed or appropriate, e.g. when PJM has committed to the construction of new transmission that will eliminate the price signal when complete or when there is not enough time to permit such new entry. The relevant rules can and should be changed.[200]

The planning process should, to the extent possible, evaluate the impact of the loss of units at risk and determine in advance whether transmission upgrades are required.[201] It is essential that PJM look forward and attempt to plan for foreseeable unit retirements, whether for economic or regulatory reasons.

200 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).

201 *See, e.g.*, 140 FERC ¶ 61,237 at P 36 (2012) ("The evaluation of alternatives to an SSR designation is an important step that deserves the full consideration of MISO and its stakeholders to ensure that SSR Agreements are used only as a 'limited, last-resort measure.'"); 118 FERC ¶ 61,243 at P 41 (2007) ("the market participants that pay for the agreements pay out-of-market prices for the service provided under the RMR agreements, which broadly hinders market development and performance.[footnote omitted] As a result of these factors, we have concluded that RMR agreements should be used as a last resort."); 110 FERC ¶ 61,315 at P 40 (2005) ("The Commission has stated on several occasions that it shares the concerns . . . that RMR agreements not proliferate as an alternative pricing option for generators, and that they are used strictly as a last resort so that units needed for reliability receive reasonable compensation.").

While not all retirements are completely foreseeable, improvement is needed in the process for ensuring that planning is looking at the probability of retirements, especially of resources that are critical to locational reliability in order to minimize the duration of any RMR requirement.

The actual implementation of Part V of the tariff has resulted in overpayment of the RMR resources. It is essential that the compensation provisions of Part V of the tariff be modified to ensure payment of all but only the actual costs incurred by the generation owner to provide the service, plus an incentive. Generators operating in competitive markets should be required, as an obligation of receiving interconnection service and having the ability to participate in competitive markets, to provide service under Part V on an incremental cost plus incentive basis when they are needed for reliability.

When notified of an intended deactivation, the MMU performs a market power study to ensure that the deactivation is economic, not an exercise of market power through withholding, and consistent with competition.[202] If the MMU determines that expected revenues exceed avoidable costs and therefore that the deactivation is not economic, the MMU will inform the unit owner that there is a market power issue. The MMU has no authority to prevent the retirement. The MMU can pursue the matter at FERC. Part V status by itself creates market power for the retiring resource. The owners of Part V resources have threatened to shut down the resources and put the grid at risk if they do not receive their requested level of Part V payments. Such exercises of market power have been effective in increasing payments to Part V units during the settlement proceedings that have resolved all Part V filings, generally on a black box basis.

PJM performs a system study to determine whether the system can accommodate the deactivation on the desired date, and if not, when it could.[203] If PJM determines that it needs a unit for a period beyond the intended deactivation date, PJM will request a unit to remain in service for a defined period.[204] The PJM market rules do not require an owner to remain in service. Owners must provide notice of a proposed deactivation at least twelve months prior to the desired deactivation date, although the advance notice can be too short to permit new generation to enter (See Table 5-31).[205] [206] The owner of a generation capacity resource must provide notice of a proposed deactivation in order to avoid a requirement to offer in RPM auctions.[207] In order to avoid submitting an offer for a unit in the next three-year forward RPM base residual auction based on retirement, an owner must submit a preliminary RPM must offer exception request no later than September 1 preceding the BRA and a final RPM must offer exception request demonstrating "a documented plan in place to retire the resource," including a notice of deactivation filed with PJM no later than December 1 preceding the BRA.[208]

Under the current rules, a unit remaining in service at PJM's request can recover its costs of continuing to operate under either the deactivation avoidable cost rate (DACR), which is a formula rate, or the cost of service recovery rate. The deactivation avoidable cost rate is designed to permit the recovery of the costs of the unit's "continued operation," termed "avoidable costs," plus an incentive adder.[209] Avoidable costs are defined to mean "incremental expenses directly required for the operation of a generating unit." [210] The incentives escalate for each year of service (first year, 10 percent; second year, 20 percent; third year, 35 percent; fourth year, 50 percent).[211] The rules provide terms for the repayment of project investment by owners of units that choose to keep units in service after the defined period ends.[212] The amount of project investment recovered cannot exceed the actual amount of the PI.[213] The cost of service rate is designed to permit the recovery of the unit's "cost of service rate to recover the entire cost of operating the generating unit" if the generation owner files a separate rate schedule at FERC.[214]

202 OATT § 113.2; OATT Attachment M § IV.1.
203 OATT § 113.2.
204 *Id.*

205 See Letter Order, FERC Docket No. ER25-1501-000 (April 15, 2025).
206 OATT § 113.1.
207 OATT Attachment DD § 6.6(g).
208 *Id.*
209 OATT § 114 (Deactivation Avoidable Credit = ((Deactivation Avoidable Cost Rate + Applicable Multiplier) * MW capability of the unit * Number of days in the month) + (APIR * First Year Multiplier) – Actual Net Revenues).
210 OATT § 115.
211 *Id.*
212 OATT § 118.
213 OATT §§ 115.
214 OATT § 119.

The DACR is unnecessarily prescriptive about the nature of the incremental costs needed to provide service, and includes unsupported escalation to extremely high incentive rates.

Table 5-34 shows units that have provided Part V reliability service to PJM, including the Indian River 4 unit, which began providing RMR service on June 1, 2022, and ended on February 24, 2025, and Brandon Shores 1 and 2 and Wagner 3 and 4 which began providing RMR service on June 1, 2025.[215] Only two of nine owners have used the deactivation avoidable cost rate approach. The other seven owners used the cost of service recovery rate. For units using the cost of service recovery rate option, revenues have averaged about 2.9 times the corresponding market price of capacity while for units using the deactivation avoidable cost rate, revenues have averaged about 1.6 times the corresponding market price of capacity.[216]

Table 5-34 Part V reliability service summary

Unit Names	Owner	Fuel Type	ICAP (MW)	Cost Recovery Method	Docket Numbers	Start of Term	End of Term
Brandon Shores 1	Talen Energy Corporation	Coal	635.0	Cost of Service Recovery Rate	ER24-1790	01-Jun-25	31-Dec-28
Brandon Shores 2	Talen Energy Corporation	Coal	638.0	Cost of Service Recovery Rate	ER24-1790	01-Jun-25	31-Dec-28
Wagner 3	Talen Energy Corporation	Coal	305.0	Cost of Service Recovery Rate	ER24-1787	01-Jun-25	31-Dec-28
Wagner 4	Talen Energy Corporation	Oil	397.0	Cost of Service Recovery Rate	ER24-1787	01-Jun-25	31-Dec-28
Indian River 4	NRG Power Marketing LLC	Coal	410.0	Cost of Service Recovery Rate	ER22-1539	01-Jun-22	24-Feb-25
B.L. England 2	RC Cape May Holdings, LLC	Coal	150.0	Cost of Service Recovery Rate	ER17-1083	01-May-17	01-May-19
Yorktown 1	Dominion Virginia Power	Coal	159.0	Deactivation Avoidable Cost Rate	ER17-750	06-Jan-17	13-Mar-18
Yorktown 2	Dominion Virginia Power	Coal	164.0	Deactivation Avoidable Cost Rate	ER17-750	06-Jan-17	13-Mar-18
B.L. England 3	RC Cape May Holdings, LLC	Oil	148.0	Cost of Service Recovery Rate	ER17-1083	01-May-17	24-Jan-18
Ashtabula	FirstEnergy Service Company	Coal	210.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	11-Apr-15
Eastlake 1	FirstEnergy Service Company	Coal	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Eastlake 2	FirstEnergy Service Company	Coal	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Eastlake 3	FirstEnergy Service Company	Coal	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Lakeshore	FirstEnergy Service Company	Coal	190.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Elrama 4	GenOn Power Midwest, LP	Coal	171.0	Cost of Service Recovery Rate	ER12-1901	01-Jun-12	01-Oct-12
Niles 1	GenOn Power Midwest, LP	Coal	109.0	Cost of Service Recovery Rate	ER12-1901	01-Jun-12	01-Oct-12
Cromby 2 and Diesel	Exelon Generation Company, LLC	Natural gas/oil, Diesel	203.7	Cost of Service Recovery Rate	ER10-1418	01-Jun-11	01-Jan-12
Eddystone 2	Exelon Generation Company, LLC	Coal	309.0	Cost of Service Recovery Rate	ER10-1418	01-Jun-11	01-Jun-12
Brunot Island CT2A, CT2B, CT3 and CC4	Orion Power MidWest, L.P.	Natural gas	244.0	Cost of Service Recovery Rate	ER06-993	16-May-06	05-Jul-07
Hudson 1	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	Natural gas	355.0	Cost of Service Recovery Rate	ER05-644, ER11-2688	25-Feb-05	08-Dec-11
Sewaren 1-4	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	Natural gas	453.0	Cost of Service Recovery Rate	ER05-644	25-Feb-05	01-Sep-08

215 See PJM, "Informational Filing Regarding Formal Notice of Termination of Reliability Must-Run Service," Docket Nos. ER22-2539-000 and ER23-2688-000 (December 23, 2024); See 191 FERC ¶ 61,098 (2025); Offer of Settlement, Docket No. ER24-1787, -1790 (January 1, 2025), Exhibit 2.
216 The final rates for Brandon Shores and Wagner have not been established.

Table 5-35 Part V reliability service cost summary[217 218 219]

		Initial Filing		Actual		Weighted Average RPM
Unit Names	Owner	Total Cost	Cost per MW-day	Total Cost	Cost per MW-day	Clearing Price ($ per MW-day)
Brandon Shores 1	Talen Energy Corporation	$327,039,342	$393.45	$137,708,201	$794.37	$318.45
Brandon Shores 2	Talen Energy Corporation	$328,584,409	$393.45	$138,358,791	$794.37	$318.45
Wagner 3	Talen Energy Corporation	$64,791,528	$162.29	$32,517,154	$390.53	$318.45
Wagner 4	Talen Energy Corporation	$84,335,202	$162.29	$42,325,606	$390.53	$318.45
Indian River 4	NRG Power Marketing LLC	$357,065,662	$871.76	$198,617,019	$484.92	$54.04
B.L. England 2	RC Cape May Holdings, LLC	$35,953,561	$328.34	$51,779,892	$472.88	$154.51
Yorktown 1	Dominion Virginia Power	$9,739,434	$142.12	$8,427,011	$122.97	$134.64
Yorktown 2	Dominion Virginia Power	$10,045,705	$142.12	$9,529,149	$134.81	$134.64
B.L. England 3	RC Cape May Holdings, LLC	$28,710,481	$723.84	$10,058,665	$253.60	$138.95
Ashtabula	FirstEnergy Service Company	$35,236,541	$176.25	$25,177,042	$125.94	$107.91
Eastlake 1	FirstEnergy Service Company	$20,842,416	$257.01	$18,484,399	$227.93	$102.73
Eastlake 2	FirstEnergy Service Company	$20,182,025	$248.87	$17,683,994	$218.06	$102.73
Eastlake 3	FirstEnergy Service Company	$20,192,938	$249.00	$17,391,797	$214.46	$102.73
Lakeshore	FirstEnergy Service Company	$33,993,468	$240.47	$20,532,969	$145.25	$102.73
Elrama 4	GenOn Power Midwest, LP	$15,435,472	$739.88	$7,576,435	$363.17	$75.08
Niles 1	GenOn Power Midwest, LP	$9,510,580	$715.19	$4,829,423	$363.17	$75.08
Cromby 2 and Diesel	Exelon Generation Company, LLC	$20,213,406	$463.70	$17,776,658	$407.80	$108.63
Eddystone 2	Exelon Generation Company, LLC	$165,993,135	$1,467.74	$85,364,570	$754.81	$108.63
Brunot Island CT2A, CT2B, CT3 and CC4	Orion Power MidWest, L.P.	$60,933,986	$601.76	$23,507,795	$232.15	$89.78
Hudson 1	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	$28,934,341	$32.90	$62,364,359	$70.92	$132.72
Sewaren 1-4	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	$47,633,115	$81.89	$79,580,435	$136.82	$97.39

In each of the cost of service recovery rate filings for Part V reliability service, the scope of recovery permitted under the cost of service approach defined in Section 119 has been a significant issue. Owners have sought to recover fixed costs, incurred prior to the noticed deactivation date, in addition to the cost of operating the generating unit. Owners have cited the cost of service reference to mean that the unit is entitled to file to recover sunk costs that it was unable to recover in the competitive markets, in addition to recovery of costs of actually providing the Part V reliability service.

The cost of service recovery rate approach has been interpreted by the companies using that approach to allow the company to develop the type of rate case filing used by regulated utilities, using a test year with adjustments, to establish a rate base including investment in the existing plant and new investment necessary to remain in service and to earn a return on that rate base and receive depreciation of that rate base, plus guarantee recovery of estimated operation and maintenance expenses without verification of actual expenses. Despite the asserted reliance on traditional cost of service ratemaking principles, in practice generators seek approval of high rates that have weak or non existent support in law and fact relative to what has been traditionally required to justify of cost

217 Actual cost data includes RMR charges through February 28, 2026.
218 The actual cost data for Indian River 4 include a refund of the difference between the filed rate that was collected pending resolution and the RMR settlement amount.
219 The data reported for Brandon Shores and Wagner are the Settlement gross costs. See 191 FERC ¶ 61,098 (2025); Offer of Settlement, Docket No. ER24-1787, -1790 (January 1, 2025), Exhibit 2.

of service rates. Companies developing the cost of service recovery rate have ignored the tariff's limitation to the costs of operating the unit during the Part V reliability service period and have included costs incurred prior to the decision to deactivate and costs associated with closing the unit that would have been incurred regardless of the Part V reliability service period.[220] In some cases, the filing included costs that already had been written off, or impaired, on the company's public books.[221] [222] In another case, the filing ignored evidence of actual book value based on market purchase of the asset.[223] The cost of service recovery rates substantially exceed the actual costs of operating to provide the reliability required by PJM. The costs are generally not subject to review, audit and verification. The Commission has approved black box settlement rates (i.e., no explicit basis for the rate is stated) that included arbitrarily inflated asset values and costs, despite protests.[224]

Because such units are needed by PJM for reliability reasons, and the provision of the service is voluntary in PJM, owners of units that PJM needs to remain in service after the desired retirement date have significant market power in establishing the terms of this reliability service which have generally been set through settlements.

This reliability service should be provided to PJM customers at reasonable rates, which reflect the relatively low risk nature of providing such service to owners, the reliability need for such service and the opportunity for owners to be guaranteed recovery of 100 percent of the actual incremental costs required to operate to provide the service plus an incentive.

The MMU recommends elimination of both the cost of service recovery rate in OATT Section 119 and the deactivation avoidable cost rate in Part V, 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 an incentive.

220 See, e.g., FERC Dockets Nos. ER10-1418-000, ER12-1901-000 and ER17-1083-000.
221 See GenOn Filing, Docket No. ER12-1901-000 (May 31, 2012) at Exh. No. GPM-1 at 9:16–21.
222 See NRG Filing, Docket No. ER22- 1539-000 (April 1, 2022).
223 See Brandon Shores, H.A. Wagner, Docket No. ER24-1787-000, et al. (April 18, 2024); Comments of the Independent Market Monitor for PJM in Opposition to Settlement, Docket No. ER24-1787-000, et al. (February 18, 2025).
224 See 190 FERC ¶ 61,026 (2025), *reh'g denied*, 191 FERC ¶ 61,170 (2025), *appeal pending* (D.C. Cir. Case No. 25-1260); 191 FERC ¶ 61,098 (2025), *reh'g denied*, 191 FERC ¶ 62,189 (2025).

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 no responsibility for paying previously incurred (sunk) costs, including a return on or of prior investments.

The Indian River RMR was effective from June 1, 2022, through February 24, 2025. After the RMR ended, Indian River submitted additional bills until the final invoice for October 2025. Additional costs beyond February 2025 were incurred for the removal of remaining coal inventory and chemicals. The MMU was unable to review all costs charged to the project because NRG refused to provide supporting documentation after several requests from the MMU. NRG only provided invoices over $10,000 starting January 2024. NRG did not provide supporting documentation for costs prior to January 2024 and for costs under $10,000. As a result, the MMU was unable to determine if all costs charged to the project were reasonable. On February 20, 2026, the MMU filed a Petition with FERC to require NRG to produce the requested cost documentation.[225]

Department of Energy (DOE) 202(c) Orders

Eddystone

On May 30, 2025, the Department of Energy (DOE) issued an order under Section 202(c) of the Federal Power Act stating that the operational availability and economic dispatch of Eddystone units 3 and 4 is necessary to meet an emergency and serve the public interest.[226] The order requires that Constellation Energy, LLC and PJM take measures to ensure that Eddystone units 3 and 4 are available to operate from May 30, 2025, initially through 5:03 PM EDT on August 28, 2025.[227] The term of operation was extended,

225 See *Petition of Monitoring Analytics, LLC, LLC for Order Directing Production of Information*, Docket No. EL26-xx (February 20, 2026).
226 16 U.S.C. § 824a(c).
227 Department of Energy, Order No. 202-25-4 (May 30, 2025) <https://www.energy.gov/ ceser/federal-power-act-section-202c-pjm-interconnection> .

including to May 24, 2026, in subsequent orders.[228] [229] Eddystone Units 3 and 4 were previously scheduled to retire on May 31, 2025.

PJM and Constellation notified the Commission by letter dated June 26, 2025, that they had agreed to a rate for service under Section 202(c) based on a modified version of the Deactivation Avoidable Cost Credit method included in Section 114 of the OATT. The modified approach ensure rates based on the actual fuel costs for operating the units and a reasonable approximation of actual avoidable costs rather than the arbitrary regulated cost of service model in recent RMR cases.

On January 25, 2026, in response to an application filed by PJM, DOE issued an emergency order pursuant to section 202(c) allowing PJM to run all electric generating units located within the PJM Region up to their maximum generation output levels, notwithstanding air quality or other permit limitations or fuel shortages, from January 25 to January 31, 2026.[230]

Wagner

On July 28, 2025, the Department of Energy (DOE) issued an order under Section 202(c) of the Federal Power Act stating that the operational availability and economic dispatch of H.A. Wagner Unit 4 is necessary to meet an emergency and serve the public interest.[231] The order required that PJM take measures in coordination with Talen Energy, the owner, to ensure that H.A. Wagner Unit 4 remain available to operate from July 28, 2025, initially through October 26, 2026.[232] The term of operation was extended to January 1, 2026, in a subsequent order.[233]

228 Department of Energy, Order No. 202-25-8 (August 28, 2025), https://www.energy.gov/ceser/federal-power-act-section-202c-pjm-interconnection-pjm>; <Department of Energy, Order No. 202-25-10 (November 26, 2025), <https://www.energy.gov/ceser/federal-power-act-section-202c-pjm-interconnection-pjm-order-no-202-25-10>; Department of Energy, Order No. 202-26-17 (February 23, 2026), <https://www.energy.gov/ceser/federal-power-act-section-202c-pjm-interconnection-llc-pjm-order-no-202-26-17> .

229 On June 9, 2025, the PJM Board of Managers initiated a Critical Issue Fast Path (CIFP) stakeholder process to address the allocation of costs associated with the payments to Constellation for continuing to operate Eddystone units 3 and 4. On August 15, 2025, FERC issued an order accepting PJM's cost allocation methodology related to the retention of Eddystone units 3 and 4. 192 FERC ¶ 61,159 (2025).

230 Order No. 202-26-02, < https://www.energy.gov/documents/order-no-202-26-2-pjm> .

231 Department of Energy, Order No. 202-25-6 (July 28, 2025), <https://www.energy.gov/sites/default/files/2025-07/PJM%27s%20202%28c%29%20Order%20No.%20202-25-6.pdf> .

232 *Id.*

233 Department of Energy, Order No. 202-25-6A (October 24, 2025), <https://www.energy.gov/sites/default/files/2025-10/202c%20Order%20No.%20202-25-6A_0.pdf,>

Generator Performance

Generator performance results from the interaction between the physical characteristics of the units and the level of expenditures made to maintain the capability of the units, which in turn is a function of incentives from energy, ancillary services and capacity markets. Generator performance indices include those based on total hours in a period (generator performance factors) and those based on hours when units are needed to operate by the system operator (generator forced outage rates).

Capacity Factor

Capacity factor measures the actual output of a power plant over a period of time compared to the potential output of the unit had it been running at full nameplate capacity for every hour during that period. Table 5-36 shows the capacity factors by unit type for January through March, 2025 and 2026. In the first three months of 2026, nuclear units had a capacity factor of 97.7 percent, compared to a capacity factor of 97.1 percent in the first three months of 2025; combined cycle units had a capacity factor of 67.4 percent in the first three months of 2026, compared to a capacity factor of 67.3 percent in the first three months of 2025; coal units had a capacity factor of 48.7 percent in the first three months of 2026, compared to a capacity factor of 48.3 percent in the first three months of 2025.

Table 5-36 Capacity factor (By unit type (GWh)): January through March, 2025 and 2026[234 235 236]

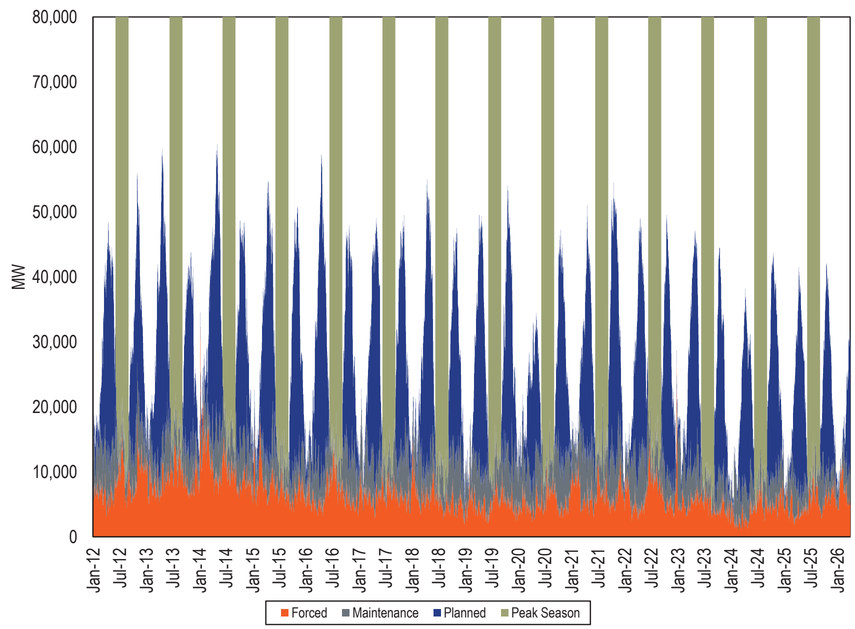
	2025 (Jan-Mar)		2026 (Jan-Mar)		
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor	Change in Capacity Factor
Battery	16.2	2.2%	30.9	3.3%	1.0%
Combined Cycle	83,969.0	67.3%	85,400.0	67.4%	0.1%
Single Fuel	74,560.3	74.7%	74,754.9	72.0%	(2.7%)
Dual Fuel	9,408.7	37.9%	10,645.1	46.6%	8.7%
Combustion Turbine	4,421.5	7.2%	6,448.3	10.5%	3.3%
Single Fuel	2,763.8	6.5%	4,112.0	9.6%	3.2%
Dual Fuel	1,657.6	8.7%	2,336.3	12.3%	3.6%
Diesel	78.7	10.0%	75.0	10.3%	0.3%
Single Fuel	69.3	9.8%	60.1	9.2%	(0.6%)
Dual Fuel	9.5	12.7%	15.0	20.2%	7.4%
Diesel (Landfill gas)	189.7	43.2%	181.1	41.3%	(1.9%)
Fuel Cell	53.3	93.3%	52.5	91.8%	(1.4%)
Nuclear	68,374.1	97.1%	68,769.7	97.7%	0.5%
Pumped Storage Hydro	1,835.3	15.7%	1,934.3	16.5%	0.8%
Run of River Hydro	2,151.1	48.5%	1,977.3	36.3%	(12.1%)
Solar	4,666.9	17.6%	5,343.8	16.6%	(1.0%)
Steam	42,937.8	42.8%	44,294.0	44.6%	1.9%
Biomass	1,263.9	66.6%	1,228.5	64.2%	(2.4%)
Coal	38,978.1	48.3%	39,151.5	48.7%	0.4%
Single Fuel	38,978.1	48.8%	39,151.5	49.6%	0.7%
Dual Fuel	0.0	0.0%	0.0	0.0%	0.0%
Natural Gas	2,431.8	46.1%	3,467.2	48.0%	1.9%
Single Fuel	113.7	56.2%	33.7	55.7%	(0.6%)
Dual Fuel	2,318.0	22.5%	3,433.5	28.8%	6.2%
Oil	264.0	4.1%	446.8	7.7%	3.7%
Wind	11,250.1	14.1%	10,724.0	21.6%	7.5%
Total	219,943.7	51.3%	225,230.9	51.6%	0.2%

Generator Performance Factors

Generator outages fall into three categories: planned, maintenance, and forced. The scheduling of planned and maintenance outages must be approved by PJM. The approval may be withdrawn in order to maintain system reliability.[237] The PJM Market Rules do not specify any consequences if the planned outage continues after PJM withdraws approval. If PJM withdraws approval for a maintenance outage during the outage and the unit cannot operate, the outage is defined to be a forced outage.[238] Outages that are approved by PJM may be extended. An extension to a planned outage that enters the peak period is treated as a forced outage. A maintenance outage that is extended to more than nine days during the peak period is treated as a forced outage.

The MW on outage vary during the year. For example, the MW on planned outage are generally highest in the spring and fall, as shown in Figure 5-10, as a result of restrictions on planned outages during the winter and summer. The Peak Period Maintenance Season, shown in Figure 5-10 as the peak season, runs from the weeks containing the twenty-fourth through thirty-sixth Wednesdays of the year. Planned outages cannot start in nor extend into this period. In 2026, the period runs from Monday, June 15 through Friday, September 11. The effect of the seasonal variation in outages can be seen in the monthly generator performance metrics in Figure 5-13.

Figure 5-10 Outages (MW): 2012 through March 2026



234 The capacity factors in this table are based on nameplate capacity values, and are calculated based on when the units come on line.
235 The subcategories of steam units are consolidated consistent with confidentiality rules. Coal is comprised of coal and waste coal. Natural gas is comprised of natural gas and propane. Oil is comprised of both heavy and light oil. Biomass is comprised of biomass, landfill gas, and municipal solid waste.
236 Hours in which batteries have net negative generation do not count toward their runtime.
237 "PJM Manual 10: Pre-Scheduling Operations," § 2.3.2 Maintenance Outage Rules, Rev. 65 (July 23, 2025).
238 OATT, Attachment K (Appendix) § 1.9.3 (b).

Table 5-37 shows the total MWh by outage type. In the first three months of 2026, forced outage MWh were 62.0 percent higher, planned outage MWh were 1.1 percent lower, and maintenance outage MWh were 25.8 percent lower than in the first three months of 2025.

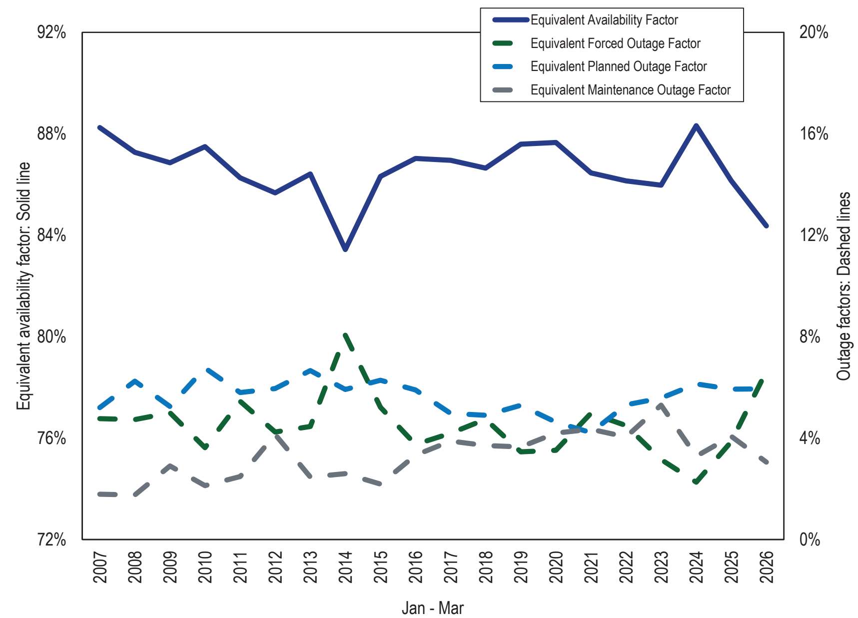
Table 5-37 Outages (MWh): January through March, 2012 through 2026

Jan-Mar	Forced MWh	Planned MWh	Maintenance MWh
2012	644,946	880,150	593,152
2013	746,299	994,855	373,523
2014	1,318,183	867,621	366,702
2015	864,686	853,173	331,012
2016	521,638	918,511	466,628
2017	597,092	662,031	538,223
2018	664,070	723,938	513,340
2019	494,156	695,494	495,231
2020	460,855	614,706	557,296
2021	706,413	500,537	620,203
2022	544,111	641,062	506,777
2023	433,641	592,430	618,364
2024	260,401	596,660	434,870
2025	394,908	566,426	397,087
2026	639,919	560,328	294,455
Change in 2026 from 2025	62.0%	(1.1%)	(25.8%)

Performance factors include the equivalent availability factor (EAF), the equivalent maintenance outage factor (EMOF), the equivalent planned outage factor (EPOF) and the equivalent forced outage factor (EFOF). These four factors add to 100 percent for any generating unit. The EAF is the proportion of hours in a year when a unit is available to generate at full capacity while the three outage factors include all the hours when a unit is unavailable. The EMOF is the proportion of hours in a year when a unit is unavailable because of maintenance outages and maintenance deratings. The EPOF is the proportion of hours in a year when a unit is unavailable because of planned outages and planned deratings. The EFOF is the proportion of hours in a year when a unit is unavailable because of forced outages and forced deratings.

The PJM aggregate EAF, EFOF, EPOF, and EMOF are shown in Figure 5-11. Metrics by unit type are shown in Table 5-38. The PJM aggregate equivalent availability factor in the first three months of 2026 was 84.4 percent, a decrease from 86.1 percent in the first three months of 2025.

Figure 5-11 Equivalent outage and availability factors: January through March, 2007 through 2026



The PJM aggregate equivalent availability factor in the first three months of 2026 was 84.4 percent, a decrease from 86.1 percent in the first three months of 2025.

Table 5-38 EFOF, EPOF, EMOF and EAF by unit type: January through March, 2007 through 2026

	Coal				Combined Cycle				Combustion Turbine				Diesel				Hydroelectric				Nuclear				Other				Total			
Jan-Mar	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF
2007	7%	6%	2%	85%	1%	7%	2%	90%	6%	3%	3%	89%	8%	0%	2%	90%	1%	8%	2%	89%	0%	5%	0%	94%	8%	5%	3%	85%	5%	5%	2%	88%
2008	8%	6%	2%	83%	2%	3%	1%	93%	4%	4%	1%	90%	10%	0%	1%	89%	1%	9%	1%	89%	2%	7%	1%	91%	3%	7%	3%	86%	5%	6%	2%	87%
2009	7%	6%	4%	83%	4%	6%	1%	89%	1%	3%	2%	94%	7%	0%	2%	91%	2%	11%	1%	87%	4%	3%	1%	91%	5%	6%	7%	82%	5%	5%	3%	87%
2010	7%	9%	4%	81%	2%	5%	1%	92%	2%	2%	1%	95%	4%	1%	1%	94%	1%	9%	1%	89%	1%	7%	0%	92%	3%	7%	2%	88%	4%	7%	2%	87%
2011	10%	7%	4%	78%	4%	9%	0%	86%	1%	2%	1%	95%	3%	0%	4%	94%	2%	10%	1%	87%	2%	3%	1%	94%	4%	5%	3%	88%	5%	6%	2%	86%
2012	8%	8%	8%	76%	2%	7%	2%	90%	1%	2%	1%	95%	2%	0%	1%	97%	2%	4%	1%	93%	1%	6%	1%	93%	5%	6%	4%	86%	4%	6%	4%	86%
2013	7%	10%	4%	79%	1%	9%	4%	86%	5%	3%	0%	92%	4%	0%	1%	95%	0%	4%	2%	93%	0%	3%	0%	96%	8%	7%	2%	83%	4%	7%	2%	86%
2014	11%	6%	4%	80%	4%	10%	1%	85%	15%	4%	1%	80%	15%	0%	2%	82%	1%	9%	6%	84%	1%	5%	0%	94%	11%	8%	4%	77%	8%	6%	3%	83%
2015	9%	6%	4%	82%	2%	9%	1%	88%	4%	3%	1%	92%	10%	0%	2%	88%	2%	10%	1%	87%	2%	5%	1%	93%	9%	11%	4%	76%	5%	6%	2%	86%
2016	8%	6%	7%	80%	2%	4%	2%	92%	2%	2%	2%	94%	6%	0%	3%	91%	2%	5%	4%	89%	0%	5%	0%	94%	4%	16%	4%	77%	4%	6%	3%	87%
2017	10%	7%	9%	75%	3%	5%	1%	91%	1%	2%	2%	95%	5%	0%	1%	94%	2%	6%	4%	88%	0%	5%	1%	94%	2%	5%	5%	88%	4%	5%	4%	87%
2018	11%	7%	8%	74%	2%	2%	1%	95%	2%	2%	2%	94%	6%	1%	3%	90%	3%	4%	2%	90%	0%	5%	0%	95%	5%	8%	7%	81%	5%	5%	4%	87%
2019	9%	4%	7%	80%	1%	5%	2%	92%	2%	5%	2%	92%	6%	1%	3%	90%	1%	6%	3%	90%	0%	5%	1%	94%	3%	9%	7%	80%	3%	5%	4%	88%
2020	4%	4%	11%	81%	6%	5%	1%	88%	2%	4%	1%	93%	7%	0%	3%	90%	3%	4%	2%	91%	2%	4%	1%	93%	3%	9%	4%	84%	4%	5%	4%	88%
2021	9%	5%	11%	76%	2%	5%	2%	91%	1%	4%	2%	93%	6%	0%	3%	91%	16%	1%	2%	81%	0%	4%	2%	94%	14%	5%	2%	79%	5%	4%	4%	86%
2022	11%	7%	9%	74%	2%	6%	3%	89%	2%	4%	2%	92%	10%	1%	5%	85%	5%	3%	2%	90%	0%	4%	1%	94%	4%	6%	4%	86%	4%	5%	4%	86%
2023	7%	6%	11%	76%	3%	5%	2%	90%	2%	4%	2%	92%	13%	0%	4%	83%	2%	17%	6%	75%	0%	4%	2%	94%	5%	9%	9%	77%	3%	6%	5%	86%
2024	4%	7%	7%	82%	2%	5%	2%	91%	2%	4%	2%	92%	9%	0%	2%	89%	3%	18%	3%	77%	1%	4%	3%	93%	3%	11%	2%	83%	2%	6%	3%	88%
2025	9%	7%	9%	74%	2%	5%	2%	91%	4%	3%	2%	91%	13%	2%	1%	84%	2%	11%	6%	81%	0%	5%	2%	93%	7%	9%	4%	80%	4%	6%	4%	86%
2026	13%	8%	6%	73%	4%	7%	2%	87%	8%	4%	2%	86%	16%	4%	4%	76%	1%	6%	4%	89%	1%	4%	2%	94%	16%	9%	4%	71%	7%	6%	3%	84%

Generator Outage Rates

The most fundamental forced outage rate metric is the equivalent demand forced outage rate (EFORd). EFORd is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate. EFORd measures the forced outage rate during periods of demand, and does not include planned or maintenance outages. A period of demand is a period during which a generator is running or needed to run. EFORd calculations use historical performance data, including equivalent forced outage hours, service hours, average forced outage duration, average run time, average time between unit starts, available hours and period hours.[239] The EFORd metric includes all forced outages, regardless of the reason for those outages.

The average PJM EFORd in the first three months of 2026 was 8.6 percent, an increase from 6.0 percent in the first three months of 2025. Figure 5-12 shows the average EFORd since 1999 for all units in PJM.[240]

239 Equivalent forced outage hours are the sum of all forced outage hours in which a generating unit is fully inoperable and all partial forced outage hours in which a generating unit is partially inoperable, prorated to full hours.
240 The universe of units in PJM changed as the PJM footprint expanded and as units retired from and entered PJM markets. See the *2019 State of the Market Report for PJM*, Appendix A: "PJM Overview" for details.

Figure 5-12 Equivalent demand forced outage rates (EFORd): 1999 through March, 2026

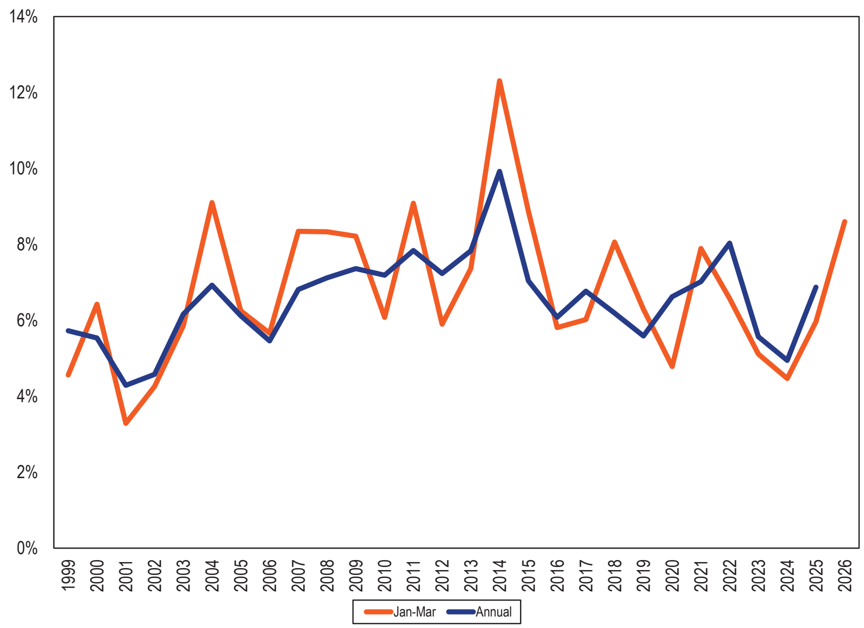


Table 5-39 shows the class average EFORd by unit type.

Table 5-39 EFORd by unit type: January through March, 2007 through 2026

	Jan-Mar																			
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Coal	7.8%	8.8%	8.5%	8.4%	12.2%	9.9%	8.7%	12.0%	10.0%	9.6%	12.7%	14.1%	11.9%	6.2%	11.8%	12.1%	11.3%	6.4%	11.5%	16.3%
Combined Cycle	8.5%	7.4%	5.6%	3.0%	5.3%	2.6%	1.1%	6.8%	2.4%	3.3%	3.3%	3.0%	2.8%	6.3%	2.4%	3.3%	4.3%	2.9%	2.6%	4.9%
Combustion Turbine	22.6%	18.5%	15.0%	11.6%	13.3%	6.0%	18.3%	30.5%	17.5%	8.6%	4.4%	10.9%	9.7%	5.4%	4.8%	7.0%	5.4%	8.9%	8.9%	12.5%
Diesel	9.2%	10.2%	8.3%	6.3%	5.3%	2.8%	3.9%	16.0%	11.0%	7.1%	6.1%	6.7%	6.8%	7.6%	6.3%	10.2%	14.8%	11.5%	16.0%	18.7%
Hydroelectric	1.6%	3.0%	2.0%	0.9%	2.2%	2.8%	0.6%	1.5%	2.4%	3.2%	3.1%	3.6%	1.2%	4.0%	16.9%	6.4%	1.6%	3.3%	5.7%	1.2%
Nuclear	0.4%	1.6%	4.0%	0.8%	1.7%	0.8%	0.2%	1.1%	1.6%	0.5%	0.5%	0.4%	0.3%	2.3%	0.2%	0.5%	0.1%	0.7%	0.3%	0.9%
Other	11.2%	10.1%	10.9%	5.1%	13.4%	4.6%	10.4%	19.6%	17.4%	6.4%	6.3%	12.9%	6.6%	2.9%	29.9%	11.2%	4.5%	4.8%	9.0%	20.0%
Total	8.3%	8.3%	8.2%	6.1%	9.1%	5.9%	7.4%	12.3%	8.9%	5.8%	6.0%	8.1%	6.3%	4.8%	7.9%	6.6%	5.1%	4.5%	6.0%	8.6%

EFORd vs EAF

EFORd is not an adequate measure of unit availability because EFORd measures only forced outages and does not account for planned or maintenance outages. Forced outage rates can be managed under the existing outage rules. The EAF (Equivalent Availability Factor), which reflects all forced, planned, and maintenance outages, is a more accurate measure of the capacity actually available to meet load.

Table 5-40 shows the differences between EFORd and EAF by unit type.

Table 5-40 EFORd and EAF by unit type: January through March, 2012 through 2026

	Unit Types															
	Coal		Combined Cycle		Combustion Turbine		Diesel		Hydroelectric		Nuclear		Other		All	
Jan-Mar	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF
2012	9.9%	23.6%	2.6%	10.5%	6.0%	4.7%	2.8%	2.8%	2.8%	7.2%	0.8%	7.3%	4.6%	14.1%	5.9%	14.3%
2013	8.7%	21.3%	1.1%	13.9%	18.3%	8.2%	3.9%	5.0%	0.6%	6.6%	0.2%	3.8%	10.4%	17.4%	7.4%	13.6%
2014	12.0%	20.4%	6.8%	15.1%	30.5%	19.6%	16.0%	17.7%	1.5%	16.5%	1.1%	5.8%	19.6%	23.3%	12.3%	16.6%
2015	10.0%	18.1%	2.4%	12.2%	17.5%	8.2%	11.0%	12.3%	2.4%	13.5%	1.6%	6.8%	17.4%	23.9%	8.9%	13.7%
2016	9.6%	20.4%	3.3%	8.0%	8.6%	6.2%	7.1%	9.0%	3.2%	11.3%	0.5%	6.0%	6.4%	23.2%	5.8%	13.0%
2017	12.7%	25.4%	3.3%	8.7%	4.4%	5.1%	6.1%	6.3%	3.1%	11.5%	0.5%	5.7%	6.3%	11.9%	6.0%	13.0%
2018	14.1%	26.0%	3.0%	4.9%	10.9%	5.8%	6.7%	9.9%	3.6%	9.6%	0.4%	5.5%	12.9%	19.1%	8.1%	13.4%
2019	11.9%	20.0%	2.8%	8.5%	9.7%	8.2%	6.8%	10.3%	1.2%	9.8%	0.3%	6.3%	6.6%	19.7%	6.3%	12.4%
2020	6.2%	18.9%	6.3%	12.4%	5.4%	7.4%	7.6%	9.8%	4.0%	8.8%	2.3%	7.3%	2.9%	16.3%	4.8%	12.3%
2021	11.8%	24.5%	2.4%	8.5%	4.8%	7.0%	6.3%	9.1%	16.9%	19.1%	0.2%	5.5%	29.9%	21.5%	7.9%	13.5%
2022	12.1%	26.3%	3.3%	11.5%	7.0%	8.2%	10.2%	15.3%	6.4%	10.5%	0.5%	5.7%	11.2%	14.0%	6.6%	13.9%
2023	11.3%	24.1%	4.3%	10.2%	5.4%	7.7%	14.8%	17.4%	1.6%	24.8%	0.1%	5.6%	4.5%	23.2%	5.1%	14.0%
2024	6.4%	17.9%	2.9%	8.6%	8.9%	7.8%	11.5%	11.2%	3.3%	22.9%	0.7%	7.2%	4.8%	16.6%	4.5%	11.7%
2025	11.5%	25.6%	2.6%	8.8%	8.9%	8.8%	16.0%	15.8%	5.7%	19.0%	0.3%	7.2%	9.0%	20.1%	6.0%	13.9%
2026	16.3%	27.4%	4.9%	12.8%	12.5%	13.9%	18.7%	23.6%	1.2%	11.4%	0.9%	6.1%	20.0%	28.7%	8.6%	15.6%
Average	11.0%	22.7%	3.5%	10.3%	10.6%	8.5%	9.7%	11.7%	3.8%	13.5%	0.7%	6.1%	11.1%	19.5%	6.9%	13.7%

Outage Analysis

The MMU analyzed the causes of outages for the PJM system. The metric used was lost generation, which is the product of the duration of the outage and the size of the outage reduction. Lost generation can be converted into lost system equivalent availability.[241] On a system wide basis, the resultant lost equivalent availability from forced outages is equal to the equivalent forced outage factor (EFOF), the resultant lost equivalent availability from maintenance outages is equal to the equivalent maintenance outage factor (EMOF), and the resultant lost equivalent availability from planned outages is equal to the equivalent planned outage factor (EPOF).

The PJM EFOF was 6.6 percent in the first three months of 2026. Table 5-41 shows the causes of EFOF by unit type. Forced outages for boiler tube leaks, 13.9 percent of the system EFOF, were the largest single contributor to average system EFOF across all unit types.

241 For any unit, lost generation can be converted to lost equivalent availability by dividing lost generation by the product of the generating units' capacity and period hours. This can also be done on a system basis.

Table 5-41 Contribution to PJM EFOF by unit type by cause: January through March, 2026

	Coal	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Other	System
Boiler Tube Leaks	22.2%	6.0%	0.0%	0.0%	0.0%	0.0%	15.7%	13.9%
Boiler Air and Gas Systems	10.6%	0.0%	0.0%	0.0%	0.0%	0.0%	43.4%	11.5%
Personnel or Procedure Errors	18.4%	0.1%	0.0%	2.4%	0.0%	0.0%	0.0%	9.1%
Electrical	1.3%	4.8%	20.8%	1.1%	0.8%	73.1%	0.0%	8.2%
Wet Scrubbers	15.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	7.5%
Economic	0.0%	1.1%	31.3%	14.0%	43.9%	0.0%	0.5%	6.9%
Miscellaneous (Gas Turbine)	0.0%	31.9%	9.4%	0.0%	0.0%	0.0%	0.0%	5.3%
Low Pressure Turbine	3.9%	0.0%	0.0%	0.0%	0.0%	0.0%	7.6%	3.0%
Stack Emission	4.6%	0.6%	0.1%	0.0%	0.0%	0.0%	4.8%	3.0%
Fuel, Ignition and Combustion Systems	0.0%	6.2%	9.3%	0.0%	0.0%	0.0%	0.0%	2.5%
Miscellaneous (Jet Engine)	0.0%	0.0%	12.5%	0.0%	0.0%	0.0%	0.0%	2.5%
Valves	3.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.8%
Circulating Water Systems	2.4%	4.2%	0.0%	0.0%	0.0%	0.2%	1.3%	1.8%
Generator	0.0%	15.2%	0.0%	0.1%	1.5%	0.0%	0.0%	1.7%
Miscellaneous (Generator)	0.2%	0.0%	0.2%	26.0%	7.1%	0.0%	7.2%	1.4%
Miscellaneous (Steam Turbine)	1.6%	1.9%	0.0%	0.0%	0.0%	0.0%	2.9%	1.4%
Exciter	1.0%	1.6%	2.4%	0.0%	0.8%	0.0%	0.5%	1.2%
Fuel Quality	1.9%	0.0%	0.0%	8.6%	0.0%	0.0%	1.5%	1.2%
Cooling System	2.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.1%
All Other Causes	10.8%	26.3%	13.8%	47.8%	45.8%	26.8%	14.6%	14.9%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

The PJM EMOF was 3.1 percent in the first three months of 2026. Table 5-42 shows the causes of EMOF by unit type. Maintenance outages for boiler tube leaks, 10.7 percent of the system EMOF, were the largest single contributor to average system EMOF across all unit types, although miscellaneous gas turbine issues were the largest contributors to EMOF for combustion turbines.

Table 5-42 Contribution to EMOF by unit type by cause: January through March, 2026

	Coal	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Other	System
Boiler Tube Leaks	17.5%	13.8%	0.0%	0.0%	0.0%	0.0%	14.3%	10.7%
Miscellaneous (Reactor)	0.0%	0.0%	0.0%	0.0%	0.0%	69.3%	0.0%	10.2%
Turbine	0.0%	21.1%	0.0%	0.0%	70.4%	0.0%	0.0%	8.0%
Boiler Air and Gas Systems	15.0%	0.0%	0.0%	0.0%	0.0%	0.0%	8.1%	7.6%
Miscellaneous (Gas Turbine)	0.0%	11.5%	36.4%	0.0%	0.0%	0.0%	0.0%	5.5%
Feedwater System	9.6%	8.0%	0.0%	0.0%	0.0%	0.0%	0.5%	5.3%
Core/Fuel	0.0%	0.0%	0.0%	0.0%	0.0%	30.1%	0.0%	4.4%
Cooling System	9.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	4.3%
Boiler Tube Fireside Slagging or Fouling	9.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.4%	4.3%
Miscellaneous (Balance of Plant)	3.9%	1.6%	2.8%	0.3%	0.0%	0.0%	22.5%	4.2%
Slag and Ash Removal	7.6%	0.0%	0.0%	0.0%	0.0%	0.0%	1.4%	3.6%
Electrical	0.4%	1.0%	13.7%	20.0%	19.0%	0.1%	0.0%	3.5%
NOx Reduction Systems	6.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.6%	2.8%
Auxiliary Systems	0.4%	0.0%	19.6%	0.0%	0.7%	0.0%	0.0%	2.5%
Boiler Internals and Structures	5.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%	2.5%
Lube Oil	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	27.3%	2.3%
Valves	3.8%	1.7%	0.0%	0.0%	0.0%	0.0%	0.5%	2.0%
Fuel, Ignition and Combustion Systems	0.0%	10.0%	5.8%	0.0%	0.0%	0.0%	0.0%	1.8%
Boiler Piping System	3.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.7%
All Other Causes	7.7%	31.4%	21.7%	79.7%	9.9%	0.5%	24.1%	12.7%

PJM EPOF was 5.9 percent in the first three months of 2026. Table 5-43 shows the causes of EPOF by unit type. Planned outages for miscellaneous balance of plant, 27.1 percent of the system EPOF, were the largest single contributor to average system EPOF across all unit types, although miscellaneous gas turbine issues were the largest contributors to EPOF for combustion turbines.

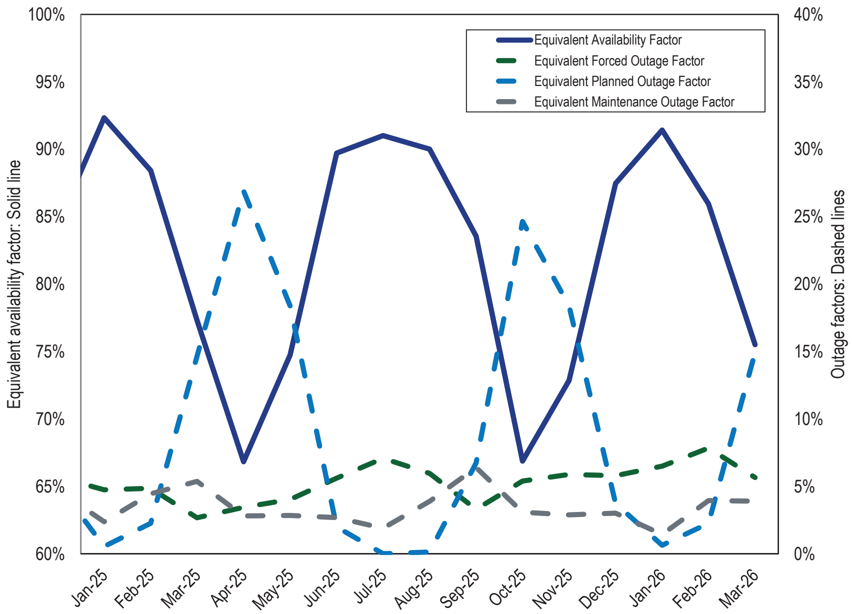
Table 5-43 Contribution to EPOF by unit type and cause: January through March, 2026

	Coal	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Other	System
Miscellaneous (Balance of Plant)	33.5%	31.0%	15.7%	0.0%	0.8%	0.0%	79.4%	27.1%
Miscellaneous (Gas Turbine)	0.0%	40.9%	77.5%	0.0%	0.0%	0.0%	0.0%	19.2%
Core/Fuel	0.0%	0.0%	0.0%	0.0%	0.0%	95.4%	0.0%	15.2%
Miscellaneous (Steam Turbine)	22.9%	8.3%	0.0%	0.0%	0.0%	0.0%	0.4%	9.6%
Boiler Overhaul and Inspections	11.2%	7.3%	0.0%	0.0%	0.0%	0.0%	16.5%	6.8%
Miscellaneous	0.0%	0.0%	0.0%	0.0%	92.8%	0.0%	0.0%	6.0%
Feedwater System	10.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.6%
Stack Emission	8.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.0%
Wet Scrubbers	8.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.8%
Turbine	0.0%	9.0%	0.0%	0.0%	5.5%	0.0%	0.0%	2.4%
Miscellaneous (Pollution Control Equipment)	4.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.4%
Miscellaneous (Generator)	0.0%	3.3%	0.1%	0.0%	0.0%	0.0%	0.1%	0.8%
Miscellaneous (Reactor)	0.0%	0.0%	0.0%	0.0%	0.0%	4.5%	0.0%	0.7%
Miscellaneous (Jet Engine)	0.0%	0.0%	5.4%	0.0%	0.0%	0.0%	0.0%	0.7%
Slag and Ash Removal	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.7%	0.2%
Electrical	0.0%	0.0%	0.8%	0.0%	0.9%	0.0%	0.0%	0.2%
Engine	0.0%	0.0%	0.0%	67.5%	0.0%	0.0%	0.0%	0.1%
Fuel, Ignition and Combustion Systems	0.0%	0.0%	0.4%	0.0%	0.0%	0.0%	0.0%	0.1%
Miscellaneous (Boiler)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.5%	0.0%
All Other Causes	0.1%	0.0%	0.0%	32.5%	0.0%	0.1%	0.4%	0.1%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Performance by Month

Monthly values for EAF, EFOF, EMOF and EPOF are shown in Figure 5-13.

Figure 5-13 Monthly generator performance factors: 2025 through March 2026



Generator Testing Issues

PJM Manual 21: Rules and Procedures for Determination of Generating Capability describes how generators are to be tested. PJM's testing requirements are not well designed, permit excessive generator discretion, and do not require adequate winter testing. As a result of the introduction of ELCC, winter capability is much more significant in defining the value of capacity that can be sold in the capacity market, especially for thermal resources. That fact makes it even more essential that PJM require winter testing and include the results of that testing in the calculation of ELCC values.

Net Capability Verification Testing data, meant to demonstrate that a unit has the ICAP claimed, are submitted for the summer and winter testing periods.[242] These periods run from the start of June until September and the start of December until March. If a unit is on a planned or maintenance outage for the entire testing period, it is expected to perform an out of period test once the outage ends. Out of period tests can be performed from the start of September until December for summer tests and from the start of March until June for winter tests. Hydroelectric generators only perform summer tests.[243] Wind and solar resources do not perform verification tests to prove capability.[244]

While data must be submitted for the winter testing period, PJM permits the use of summer test data adjusted for ambient winter conditions in lieu of actual winter test data. The MMU recommends that PJM require actual seasonal tests as part of the Summer/Winter Capability Testing rules and that the ambient conditions under which the tests are performed be defined.

Results, including failed test results, must be submitted to PJM via eGADS. Failing to submit data before the deadline can result in a Data Submission Charge of $500 per day late.[245]

Failure to demonstrate the claimed net capability results in a forced outage or derating effective from the beginning of the testing period and lasting until either a reduced claimed ICAP is in effect, the beginning of the next testing period, or, except for failures due to environmental constraints or a lack of resources, a successful out of period test.

Failed test results must be accompanied by a derating or outage in eGADS and in eDART. Failure to report failed tests and failure to derate the unit can result in a Generation Resource Rating Test Failure Charge, equal to the Daily Deficiency Rate multiplied by: the daily ICAP shortfall multiplied by one minus the effective EFORd for unlimited resources; the UCAP for the daily ICAP shortfall, for limited duration resources and combination resources.[246] Nine resources were assessed for generation resource rating test failure charges in 2024. No resources were assessed for generation resource rating test failure charges in 2025 or the first three months of 2026.

242 PJM. "PJM Manual 18: PJM Capacity Market," § 8.5 Summer/Winter Capability Testing, Rev. 62 (December 17, 2025).

243 PJM. "PJM Manual 18: PJM Capacity Market," § 8.5 Summer/Winter Capability Testing, Rev. 62 (December 17, 2025).

244 PJM. "PJM Manual 18: PJM Capacity Market," Appendix B: Calculating Capacity Values for Wind and Solar Capacity Resources, Rev. 62 (December 17, 2025).

245 "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 12, Section A.

246 PJM. "PJM Manual 18: PJM Capacity Market," § 9.1.5 Generation Resource Rating Test Failure Charge, Rev. 62 (December 17, 2025).

The Daily Deficiency Rate in dollars per MW-day is equal to the weighted average capacity resource clearing price from the RPM auction that resulted in the resource's commitment plus the greater of 20 percent of that clearing price or 20 dollars per MW-day.[247]

While generation owners are required to report failed tests and to derate their unit in eGADS, owners can perform an unlimited number of tests before submitting a successful result. The MMU recommends that PJM limit the number of tests that can be made before submitting final results and that the data be collected by PJM's Power Meter instead of being submitted in eGADS. The MMU recommends that PJM select the time and day for testing a unit, not the unit owner, and that this testing not be communicated in advance. Instead, a unit would be tested by how well it follows its dispatch signal. Under the current testing rules, generation owners have the opportunity to perform tests during more favorable conditions to achieve better performance.

Generator output is also assessed during Performance Assessment Intervals (PAIs), which occur when PJM declares an emergency action as listed in Manual 18, Section 8.4A. If a unit fails to perform as expected, generators may incur a Non-Performance Charge, which is equal to the performance shortfall multiplied by the Non-Performance Charge Rate.[248] In 2022, PAIs occurred on June 13, June 14, June 15, December 23, and December 24. For the December 23 and 24 PAIs, PJM total nonperformance charges were approximately $1.796 billion, reduced to $1.226 billion in a settlement agreement.[249] There were no such charges assessed in 2023, 2024, 2025, or the first three months of 2026.

For each day of a delivery year, generators are required to meet their daily unforced capacity commitments. Generation owners have the option to buy replacement capacity that satisfies the same locational requirements.[250] [251] Failure to meet this commitment can result in a Daily Capacity Resource Deficiency Charge.[252] [253] This charge is equal to the Daily Deficiency Rate multiplied by the difference between a resource's daily commitments and daily position. Thirty resources were assessed for deficiency charges in 2021, 65 resources were assessed for deficiency charges in 2022, 176 resources were assessed for deficiency charges in 2023, 432 resources were assessed for deficiency charges in 2024, 577 resources were assessed for deficiency charges in 2025, and 321 resources were assessed for deficiency charges in the first three months of 2026. The increase in the number of resources subject to deficiency charges is a result of the implementation of class average ELCC in the 2023/2024 Delivery Year and marginal ELCC starting in the 2025/2026 Delivery Year.

Changing Outage Types

Capacity resource owners have an incentive to minimize their forced outages to maximize capacity revenue and minimize penalties. Generation owners have had the ability to change the designation of the outage type after the initial submission to the eGADS database since 2014. Table 5-44 shows that from 2014 through March 2026, of all the changes in outage status, 96.2 percent of the outages and 86.8 percent of the outage MW were changed from either planned or maintenance to forced outage status. Of those changes to forced outage status, 41.2 percent of the outages and 82.5 percent of the MW were for coal and hydro plants.

247 OATT, Attachment DD (Reliability Pricing Model) § 7.
248 OATT, Attachment DD (Reliability Pricing Model) § 10A.
249 See Settlement Agreement, Docket No. ER23-2975-000 (September 29, 2023), which can be accessed at: <https://pjm.com/-/media/documents/ferc/filings/2023/20230929-er23-2975-000.ashx>.
250 "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," § 1.3.6 Impacts of Test Results, Rev. 19 (June 27, 2024).
251 OATT, Attachment DD (Reliability Pricing Model) § 7 (a).
252 PJM. "PJM Manual 18: PJM Capacity Market," § 8.2 RPM Commitment Compliance, Rev. 62 (December 17, 2025).
253 OATT, Attachment DD (Reliability Pricing Model) § 8.

Table 5-44 Changed outages by unit type: 2014 through March 2026[254]

		Forced to Maintenance		Forced to Planned		Maintenance or Planned to Forced	
Unit Type	Year	No. Outages	MWh	No. Outages	MWh	No. Outages	MWh
Coal	2014	5	270,049	0	NA	1	2,794
	2015	0	NA	0	NA	25	876,920
	2016	1	271,304	0	NA	74	1,983,852
	2017	2	151,085	0	NA	48	1,246,484
	2018	1	1,520	0	NA	30	837,286
	2019	2	71,234	0	NA	43	618,382
	2020	1	8,587	0	NA	12	170,807
	2021	0	NA	0	NA	0	NA
	2022	0	NA	0	NA	0	NA
	2023	1	13,211	0	NA	0	NA
	2024	1	18,908	0	NA	0	NA
	2025	0	NA	0	NA	0	NA
	2026 (Jan-Mar)	0	NA	0	NA	0	NA
	Total	14	805,898	0	NA	233	5,736,526
Combined Cycle	2014	1	3,803	2	1,105	1	28,067
	2015	2	24,685	0	NA	3	3,330
	2016	0	NA	1	65,664	24	145,432
	2017	3	5,786	0	NA	19	400,606
	2018	1	416	0	NA	16	52,214
	2019	0	NA	0	NA	11	94,756
	2020	0	NA	0	NA	13	19,037
	2021	0	NA	7	303,061	0	NA
	2022	0	NA	1	3,817	2	208
	2023	0	NA	0	NA	0	NA
	2024	3	2,625	0	NA	0	NA
	2025	0	NA	0	NA	2	191,610
	2026 (Jan-Mar)	0	NA	0	NA	0	NA
	Total	10	37,315	11	373,648	91	935,260
Combustion Turbine	2014	9	26,990	3	15,027	22	25,865
	2015	0	NA	0	NA	13	27,567
	2016	0	NA	0	NA	48	55,233
	2017	0	NA	0	NA	19	29,586
	2018	0	NA	2	41,737	25	24,433
	2019	0	NA	1	340	28	37,483
	2020	0	NA	0	NA	27	41,312
	2021	0	NA	0	NA	5	25,094
	2022	0	NA	0	NA	5	25,497
	2023	0	NA	0	NA	4	270,336
	2024	1	11,786	0	NA	6	191,667
	2025	0	NA	0	NA	3	3,222
	2026 (Jan-Mar)	0	NA	0	NA	0	NA
	Total	10	38,777	6	57,104	205	757,294
Diesel	2014	0	NA	0	NA	77	4,550
	2015	15	47	0	NA	182	5,439
	2016	0	NA	0	NA	217	5,579
	2017	2	145	0	NA	175	5,883
	2018	2	15	0	NA	235	4,414
	2019	0	NA	0	NA	238	23,066
	2020	2	311	0	NA	163	6,113
	2021	3	137	0	NA	3	27,059
	2022	4	5,492	0	NA	10	305
	2023	0	NA	0	NA	0	NA
	2024	0	NA	0	NA	0	NA
	2025	0	NA	0	NA	0	NA
	2026 (Jan-Mar)	0	NA	0	NA	0	NA
	Total	28	6,147	0	NA	1,300	82,408

Continued

254 Year describes the year in which the outage started and not the year in which the outage designation was changed.

Unit Type	Year	Forced to Maintenance No. Outages	Forced to Maintenance MWh	Forced to Planned No. Outages	Forced to Planned MWh	Maintenance or Planned to Forced No. Outages	Maintenance or Planned to Forced MWh
Hydroelectric	2014	1	3	0	NA	124	1,383,319
	2015	1	162	0	NA	152	952,608
	2016	4	780	0	NA	315	1,433,851
	2017	2	52,080	0	NA	123	598,766
	2018	4	82,395	0	NA	72	405,549
	2019	0	NA	0	NA	34	148,629
	2020	0	NA	0	NA	59	281,976
	2021	0	NA	0	NA	33	263,525
	2022	0	NA	0	NA	1	4,887
	2023	0	NA	0	NA	9	196,512
	2024	0	NA	0	NA	0	NA
	2025	0	NA	0	NA	0	NA
	2026 (Jan-Mar)	0	NA	0	NA	0	NA
	Total	12	135,420	0	NA	922	5,669,622
Nuclear	2014	0	NA	1	177,618	0	NA
	2015	0	NA	1	573	0	NA
	2016	0	NA	0	NA	0	NA
	2017	0	NA	0	NA	0	NA
	2018	0	NA	0	NA	0	NA
	2019	0	NA	0	NA	0	NA
	2020	0	NA	0	NA	2	22,903
	2021	0	NA	0	NA	0	NA
	2022	0	NA	0	NA	0	NA
	2023	0	NA	0	NA	0	NA
	2024	0	NA	2	168,615	0	NA
	2025	0	NA	0	NA	0	NA
	2026 (Jan-Mar)	0	NA	0	NA	0	NA
	Total	0	NA	4	346,807	2	22,903
Other	2014	5	103,981	0	NA	1	866
	2015	0	NA	0	NA	2	176,599
	2016	1	11,680	0	NA	18	159,781
	2017	2	231	1	28,636	12	85,071
	2018	3	7,555	0	NA	1	268
	2019	1	128,664	1	8,658	9	61,297
	2020	0	NA	0	NA	4	82,250
	2021	0	NA	0	NA	0	NA
	2022	0	NA	0	NA	0	NA
	2023	2	17,023	0	NA	0	NA
	2024	0	NA	0	NA	0	NA
	2025	0	NA	0	NA	0	NA
	2026 (Jan-Mar)	0	NA	0	NA	4	53,730
	Total	14	269,134	2	37,294	51	619,863
All Units	2014	21	404,826	6	193,750	226	1,445,461
	2015	18	24,894	1	573	377	2,042,463
	2016	6	283,764	1	65,664	696	3,783,728
	2017	11	209,328	1	28,636	396	2,366,397
	2018	11	91,901	2	41,737	379	1,324,165
	2019	3	199,897	2	8,998	363	983,612
	2020	3	8,898	0	NA	280	624,398
	2021	3	137	7	303,061	41	315,679
	2022	4	5,492	1	3,817	18	30,896
	2023	3	30,234	0	NA	13	466,848
	2024	5	33,319	2	168,615	6	191,667
	2025	0	NA	0	NA	5	194,832
	2026 (Jan-Mar)	0	NA	0	NA	4	53,730
	Total	88	1,292,689	23	814,853	2,804	13,823,876

6 Demand Response

Markets require both a supply side and a demand side to function effectively. The demand side of wholesale electricity markets is underdeveloped. Wholesale power markets will be more efficient when the demand side of the electricity market becomes fully functional without depending on special programs as a proxy for full participation. The current PJM demand side programs do not result in a functional demand side of the electricity market.

Overview

- **Demand Response Activity.** Demand response resources include economic demand response (energy market demand resources), emergency demand response, pre-emergency demand response and price responsive demand (PRD) (capacity market demand resources), synchronized reserves and regulation.[1]

  Total demand response revenue increased by $155.3 million, 324.4 percent, from $47.9 million in the first three months of 2025 to $203.2 million in the first three months of 2026, primarily due to increases in capacity market revenue. Emergency demand response revenue accounted for 80.6 percent of all demand response revenue, economic demand response for 8.0 percent, demand response in the synchronized reserve market for 3.0 percent and demand response in the regulation market for 8.3 percent.

  Total emergency demand response revenue increased by $134.8 million, 464.5 percent, from $29.0 million in the first three months of 2025 to $163.8 million in the first three months of 2026.[2] This increase was a result of higher capacity market prices and capacity market revenue.

  Economic demand response revenue increased by $6.0 million, 58.4 percent, from $10.3 million in the first three months of 2025 to $16.3 million in the first three months of 2026.[3] Demand response revenue in the synchronized reserve market increased by $2.9 million, 85.7 percent, from $3.3 million in the first three months of 2025 to $6.2 million in the first three months of 2026. Demand response revenue in the regulation market increased by $11.7 million, 222.7 percent, from $5.2 million in the first three months of 2025 to $16.9 million in the first three months of 2026.

- **Demand Response Energy Payments are Uplift.** Energy payments to emergency and economic demand response resources are uplift. LMP does not cover energy payments to demand response resources although emergency demand response and economic demand response can and do set LMP. Energy payments to emergency demand resources are paid by PJM market participants in proportion to their net purchases in the real-time energy 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.[4]

- **Demand Response Market Concentration.** The ownership of economic demand response resources was highly concentrated in the first three months of 2025 and 2026. The HHI for economic demand response resource reductions increased by 371 points from 8199 in the first three months of 2025 to 8570 in the first three months of 2026.

  The ownership of emergency demand response resources is highly concentrated. The HHI for emergency demand response resources committed MW was 2387 for the 2024/2025 Delivery Year. In the 2024/2025 Delivery Year, the four largest CSPs owned 88.5 percent of all committed emergency demand response UCAP MW. The HHI for emergency demand response committed MW is 2517 for the 2025/2026 Delivery Year. In the 2025/2026 Delivery Year, the four largest CSPs own 86.7 percent of all committed demand response UCAP MW.

- **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

1 Emergency demand response refers to both emergency and pre-emergency demand response.
2 The total credits and MWh numbers for demand resources were downloaded as of April 13, 2026, and may change as a result of continued PJM billing updates.
3 Economic credits are synonymous with revenue received for reductions under the economic load response program.
4 "PJM Manual 28: Operating Agreement Accounting," § 11.2.2, Rev. 104 (March 1, 2026).

with the current rules because demand resources are not registered to a node. In addition, 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 payments have been eliminated from PJM markets effective June 1, 2026. Energy efficiency resources are not capacity resources in PJM and do not clear in the capacity market. 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 2025/2026 Delivery Year. In the 2025/2026 Delivery Year, payments to EE are $148 million.
- **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 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 2025/2026 Delivery Year, with an HHI value of 2804. In the 2025/2026 Delivery Year, the four largest companies own 96.0 percent of all paid Energy Efficiency MW.

Recommendations

- The MMU recommends that PJM report the response of emergency demand response 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 performance metric should be (CBL – Metered load)/(CBL – FSL). The current approach significantly overstates the expected response to PJM dispatch. (Priority: High. First reported 2023. Status: Not adopted.)
- The MMU recommends that FSL registrations be required to reduce to their FSL and GLD registrations be required to reduce by their committed amount in every event hour. (Priority: High. First reported 2025. Status: Not adopted.)
- The MMU recommends that emergency demand response 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 emergency demand response 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 emergency demand response resources be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate.[5] (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that the maximum offer for emergency demand response resources and price response 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 emergency demand response resources be treated as economic resources, responding to economic price signals like other capacity resources. The MMU recommends that emergency demand response resources not be treated as emergency resources. The MMU recommends that emergency demand response resources be available for every hour of the year. (Priority: High. First reported 2012. Status: Partially adopted.)

5 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 prices is already provided in the economic program. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends that, if emergency demand response resources remain in the capacity market, a daily energy market must offer requirement apply to emergency demand response resources, comparable to the rule applicable to generation capacity resources.[6] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that emergency demand response 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 emergency demand response 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 all demand resources be modified to reflect compliance more accurately. (Priority: Medium. First reported 2009. Status: Not adopted.)

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

- 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. Compliance by demand resources with PJM dispatch instructions should include both increases and decreases in load. (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.[7] (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends demand response event compliance be calculated on a five minute basis for all emergency demand response resources and that the penalty structure reflect five minute compliance. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends that demand response 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 economic 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 emergency demand response resources clarify that a resource and its CSP, if any, must notify PJM of material changes affecting the capability of the resource to

7 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.

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.)

- 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.[8])
- The MMU recommends that all demand resources register as Pre-Emergency and that the Emergency Program be eliminated. (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends that the lead times for emergency demand response 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.)[9] [10]
- 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 DER aggregations that clear in a capacity auction not be permitted to change status from homogeneous demand response to any other status for any additional auctions for the same delivery year, or for the delivery year. (Priority: High. First reported Q3, 2025. 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 net metering resources be prohibited from participating in wholesale ancillary services markets if they are compensated for the service at the retail level. (Priority: Medium. First reported Q2, 2025. 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

8 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.

9 See 189 FERC ¶ 61,095.

10 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.

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.)
- The MMU recommends that PRD be required to respond during a PAI, regardless of whether the real-time LMP at the applicable location meet or exceeds the PRD strike price, to be consistent with all CP resources. (Priority: Medium. First reported Q3, 2025. Status: Not adopted.)

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 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.[11]

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.[12] The MMU proposal was based on the BGE load forecasting program

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

12 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>.

and the Pennsylvania Act 129 Utility Program.[13] [14] 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.[15] PJM's proposal includes only a THI curtailment trigger and not an overall load curtailment trigger.

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 rules proposed by the MMU.

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.[16] 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

13 *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).
14 *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).
15 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, 2018).

16 577 U.S. 260 (2016).

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. In addition, PRD is not required to respond if the LMP is less than the PRD strike price. This flawed rule meant that PRD did not fully respond during Winter Storm Elliott because PRD offered at the maximum price of $1,849 per MWh.

PJM Demand Response Programs

All PJM demand response programs can be grouped into economic demand response (energy market demand resources), emergency demand response, pre-emergency demand response and price responsive demand (PRD) (capacity market demand resources), synchronized reserves and regulation.[17] Table 6-1 provides an overview of the key features of PJM demand response programs.

Based on FERC Order No. 719 PJM implemented rules that require PJM to verify with EDCs that no law or regulation of a RERRA prohibits End Use Customers' participation. [18] [19]

17 Emergency demand response refers to both emergency and pre-emergency demand response.
18 *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 154 (2008), *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292, *order on reh'g*, Order No. 719-B, 129 FERC ¶ 61,252 (2009)
19 The evidence supplied by LDCs must take the form of an order, resolution or ordinance of the RERRA, an opinion of the RERRA's legal counsel attesting to existence of an order, resolution, or ordinance, or an opinion of the state attorney general on behalf of the RERRA attesting to existence of an order, resolution or ordinance.

Table 6-1 Overview of demand response programs

	Emergency and Pre-Emergency Demand Response Program			Economic Demand Response Program	Price Responsive Demand
	Capacity Market Demand Response			Economic Demand Response	
Product Types	Capacity Performance, Summer-Period Capacity Performance OATT Attachment DD § 5.5A	Capacity Performance,Summer-Period Capacity Performance OATT Attachmend DD § 5.5A		OATT Attachment K § 1.5A	
Market	Capacity Only OATT Attachment K § 8.1	Full Program Option (Capacity and Energy) OATT Attachemnt K § 8.1	Energy Only OATT Attachemnt K § 8.1	Energy Only	Capacity Only
Capacity Market	DR cleared in RPM	DR cleared in RPM	Not included in RPM	Not included in RPM	PRD cleared in RPM
Dispatch Requirement	Mandatory Curtailment	Mandatory Curtailment	Voluntary Curtailment	Dispatched Curtailment	Price Threshold
Capacity Payments	Capacity payments based on RPM clearing price	Capacity payments based on RPM clearing price	NA	NA	LSE PRD Credit RAA Schedule 6.1.G
Capacity Measurement and Verification	Firm Service Level Guaranteed Load Drop	Firm Service Level Guaranteed Load Drop	NA	NA	Firm Service Level
CBL	NA	Yes, as described OATT Attachment K § 3.3A	Yes, as described OATT Attachment K § 3.3A	Yes, as described OATT Attachment K § 3.3A	NA
Energy Payments	No energy payment	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment during PJM declared Emergency Event mandatory curtailments.	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment only for voluntary curtailments.	Energy payment based on full LMP. Energy payment for hours of dispatched curtailment. OATT Attachment K § 3.3A	NA
Penalties	Non-Performance Assessment OATT Attachment DD § 10A RAA Schedule 6.K Test compliance penalties OATT Attachment DD § 11A	Non-Performance Assessment OATT Attachment DD § 10A RAA Schedule 6.K Test compliance penalties OATT Attachment DD § 11A	NA	NA	Non-Performance Assessment RAA Schedule 6.1.G Test compliance penalties RAA Schedule 6.1.L
Associate Manuals	Manual 18	Manual 11 Manual 18	Manual 11 Manual 18	Manual 11	Manual 18

Non-PJM Demand Response Programs

Within the PJM footprint, states may have additional demand response programs as part of a Renewable Portfolio Standard (RPS) or a separate program. Indiana, Ohio, Pennsylvania (e.g. Pennsylvania ACT 129 Utility Program) and North Carolina include demand response in their RPS. If demand response is dispatched by a state run program, the demand response resources are ineligible to receive payments from PJM during the state dispatch.[20]

PJM Demand Response Programs

Figure 6-1 shows all revenue from PJM demand response programs by market for each year, 2008 through March 2026. Since the implementation of the RPM Capacity Market on June 1, 2007, the capacity market has been the primary source of demand response revenue.[21] In the first three months of 2026, total demand response revenue increased by $155.3 million, 324.4 percent, from $47.9 million in the first three months of 2025 to $203.2 million in the first three months of 2026, due to increases in capacity market prices and revenue. Total emergency demand response revenue increased by $134.8 million, 464.5 percent, from $29.0

20 "PJM Manual 11: Energy & Ancillary Services Market Operations," § 10.1, Rev. 136 (October 1, 2025).
21 This includes both capacity market revenue and emergency energy revenue for capacity resources.

million in the first three months of 2025 to $163.8 million in the first three months of 2026. This increase was a result of higher capacity market prices and capacity market revenue.[22] In the first three months of 2026, emergency demand response revenue, which includes capacity and emergency energy revenue, accounted for 80.6 percent of all revenue received by demand response providers, the economic program for 8.0 percent, synchronized reserve for 3.0 percent and the regulation market for 8.3 percent.

Economic demand response revenue increased by $6.0 million, 58.4 percent, from $10.3 million in the first three months of 2025 to $16.3 million in the first three months of 2026.[23] Demand response revenue in the synchronized reserve market increased by $2.9 million, 85.7 percent, from $3.3 million in the first three months of 2025 to $6.2 million in the first three months of 2026. Demand response revenue in the regulation market increased by $11.7 million, 222.7 percent, from $5.2 million in the first three months of 2025 to $16.9 million in the first three months of 2026.

Figure 6-1 Demand response revenue by market: January through March, 2008 to 2026

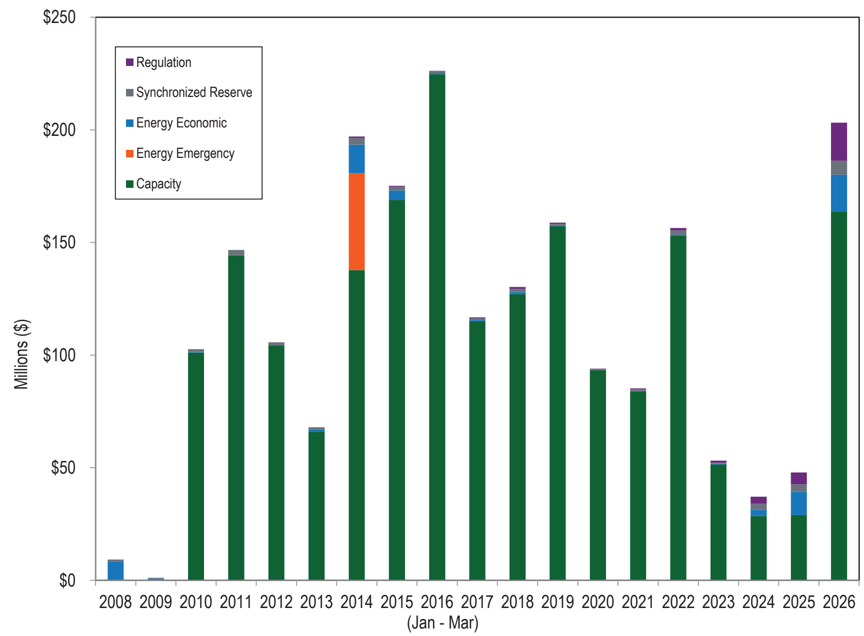


Table 6-2 shows the monthly demand response cleared volumes and revenues in the synchronized reserve market.

22 The total credits and MWh for demand resources were downloaded as of April 13, 2026, and may change as a result of continued PJM billing updates.
23 Economic credits are synonymous with revenue received for reductions under the economic load response program.

Table 6-2 Demand response synchronized reserve market MWh and revenue: January 2025 through March 2026

	MWh			Revenue		
Month	2025	2026	Percent Change	2025	2026	Percent Change
Jan	188,234	317,918	68.9%	$528,551.11	$2,101,212.23	297.5%
Feb	192,247	314,841	63.8%	$569,852.48	$1,357,402.93	138.2%
Mar	339,478	379,593	11.8%	$2,228,065.08	$2,719,030.47	22.0%
Apr	226,206			$2,013,303.75		
May	404,918			$1,673,752.10		
Jun	415,556			$2,119,535.48		
Jul	393,494			$2,362,323.88		
Aug	396,407			$1,146,787.69		
Sep	393,198			$1,600,803.08		
Oct	440,636			$2,196,860.17		
Nov	450,039			$1,620,857.94		
Dec	359,957			$1,355,664.28		
Total (Jan-Mar)	719,958	1,012,352	40.6%	$3,326,468.67	$6,177,645.63	85.7%

Table 6-3 shows the monthly demand response cleared volumes and revenues in the regulation market.

Table 6-3 Demand response regulation market MWh and revenue: January 2025 through March 2026

	MWh			Revenue		
Month	2025	2026	Percent Change	2025	2026	Percent Change
Jan	36,051	40,676	12.8%	$2,201,687.59	$5,029,880.80	128.5%
Feb	33,520	42,350	26.3%	$1,435,956.43	$7,248,158.87	404.8%
Mar	36,455	47,140	29.3%	$1,608,850.18	$4,651,747.15	189.1%
Apr	34,413			$1,107,759.21		
May	35,331			$1,148,378.85		
Jun	34,489			$1,643,056.35		
Jul	30,291			$1,280,184.34		
Aug	31,657			$1,067,364.48		
Sep	29,092			$1,278,466.14		
Oct	28,089			$3,200,499.94		
Nov	28,716			$1,548,962.74		
Dec	37,632			$2,317,751.60		
Total (Jan-Mar)	106,027	130,167	22.8%	$5,246,494.20	$16,929,786.82	222.7%

CSPs provide for each registered location the load reduction method and the associated load reduction capability. Load reduction methods indicate the type of electrical equipment that is controlled to provide the demand response activity and include: heating, ventilation and air conditioning (HVAC), lighting, refrigeration, manufacturing, water heaters, batteries, plug load, computing and generation. The computing category includes data center and crypto mining while plug load represents an electronic device that is plugged into a socket, which is not already represented by the methods described above. Examples of plug load include IT peripherals such as large computers, monitors, printers, routers, copiers and scanners or appliances such as washers, dryers or dishwashers.[24]

Table 6-4 shows the demand response capability registered to provide synchronized reserves by load reduction method.

Table 6-4 Demand response synchronized reserve load reduction methods: January through March, 2026

Method	MW	Percent
Generator	139.1	5.7%
HVAC	78.9	3.2%
Lighting	165.3	6.8%
Refrigeration	16.0	0.7%
Manufacturing	1,362.0	55.7%
Water Heaters	0.0	0.0%
Batteries	14.1	0.6%
Plug Load	1.6	0.1%
Computing	670.3	27.4%
Total	2,447.2	100.0%

Table 6-5 shows the demand response capability registered to provide regulation by load reduction method.

24 "PJM Manual 11: Energy & Ancillary Services Market Operations," § 10.2.2, Rev. 136 (October 1, 2025).

Table 6-5 Demand response regulation load reduction methods: January through March, 2026

Method	MW	Percent
Water Heaters	143.8	63.1%
Batteries	84.2	36.9%
Total	228.0	100.0%

Emergency and Pre-Emergency Demand Response Programs

Pre-Emergency is the default status for capacity market demand response resources. Emergency status is only for resources that use behind the meter generation and that generation has environmental restrictions that limit the resource's ability to operate only in emergency conditions. [25] All demand resources must register as pre-emergency unless the participant qualifies for emergency. PJM also uses the term Load Management Program to refer to the emergency and pre-emergency demand response resources.

Capacity demand response resources may be dispatched both as part of, and absent, a PAI. While demand resources dispatched during a PAI continue to be subject to Non-Performance Assessment charges, demand resources dispatched outside of a PAI are not subject to any event specific penalties.[26] If a demand resource is dispatched only outside of Performance Assessment Events for the delivery year, its performance for the delivery year is determined based on the better of actual performance or a test.[27] There are no penalties or consequences for demand response nonperformance.

For example, if a demand resource is called upon five times during the delivery year only outside of Performance Assessment events and fails to perform each time, its delivery year performance will be based only on a test. If the performance under the test is better than the actual performance, no penalties would be levied even though the resource failed to perform each time it was needed.

25 OA Schedule 1 § 8.5.
26 "PJM Manual 18: PJM Capacity Market," § 8.6, Rev. 62 (December 17, 2025).
27 "PJM Manual 18: PJM Capacity Market," § 8.7, Rev. 62 (December 17, 2025). Load Management Test.

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.

In all demand response programs, CSPs are companies that sign up end use retail customers that have the ability to reduce load. CSPs satisfy cleared RPM commitments by registering end use retail customers as Nominated MW.[28] After a demand response event occurs, PJM compensates CSPs for their participants' load reductions and CSPs in turn compensate their participants. Only CSPs are eligible to participate in the PJM demand response programs, but a participant can register as a PJM special member and become a CSP without any additional cost.

All emergency or pre-emergency demand resources must be registered as annual capacity resources. Summer period demand response resources are allowed to aggregate with winter period capacity resources to fulfill the annual requirement.[29]

The rules applied to demand resources (DR) in the current market design do not treat demand resources in a manner comparable to generation capacity resources, even though demand resources are sold in the same capacity market, are treated as a substitute for other capacity resources and displace other capacity resources in RPM auctions. PJM will not measure compliance for DR, and the resources will not face penalties, in a PAI unless the product type and lead time type are dispatched by PJM. PJM does not dispatch DR nodally like other capacity resources. DR can only be dispatched on a zonal or subzonal basis. PJM will not measure compliance for DR, and the resources will not face penalties, in a PAI if the area dispatched is not a defined subzone

28 See RAA Schedule 6. Since 2010, the PJM tariff definition of "End User Customer" limits the scope of the term to mean only PJM Members. Letter Order, Docket No. ER11-1909-000 (December 20, 2010). Recently, PJM has asserted that the reference in RAA Schedule 6 § L.1 and OATT Attachment DD-1 § L.1 to the defined term, "End Use Customer," was a mistake, and proposed to discontinue use of the defined term in the February 8, 2024, meeting of the PJM Governing Document Enhancement and Clarification Subcommittee (GDECS). The proposed change would remove the current requirement in the filed tariff that End Use Customers be PJM Members. The proposed change is substantive and not a correction of a typographical error.
29 Summer period demand response must be available for June through October and the following May between 10:00AM and 10:00PM EPT. *See* PJM OATT RAA Article 1.

or control zone. With the dispatch of DR no longer triggering a PAI, demand resources dispatched outside of a PAI are no longer subject to any event specific penalties or consequences for nonperformance.

Demand resources are not subject to the same rules as other capacity resources related to the definition of response. Increases in load are ignored when calculating the response of DR to a PJM dispatch.

Demand resources are not required to meet the same must offer requirements as other capacity resources. All other capacity resources must offer in the capacity market and all other capacity resources must offer their ICAP MW daily in the day-ahead energy market.

The MMU has made recommendations that would provide a capacity market supply side and a demand side option and that would result in treating demand resources in a manner comparable to other capacity and energy resources and in a way that would ensure that the demand side contribution to reliability is accurately measured.

Market Structure

The HHI for demand resources shows that ownership was highly concentrated for the 2024/2025 Delivery Year, with an HHI value of 2387. In the 2024/2025 Delivery Year, the four largest companies contributed 88.5 percent of all committed demand response UCAP MW. The HHI for demand resources shows that ownership is highly concentrated for the 2025/2026 Delivery Year, with an HHI value of 2517. In the 2025/2026 Delivery Year, the four largest companies own 86.7 percent of all committed demand response UCAP MW.

Table 6-6 shows the HHI value for committed Demand Response UCAP MW and the market share of the four largest suppliers by delivery year.

Table 6-6 Demand Response HHI: 2019/2020 through 2025/2026 Delivery Years

Delivery Year	HHI	Structure	Top 4 Market Share
2019/2020	1840	Highly Concentrated	79.1%
2020/2021	2523	Highly Concentrated	88.4%
2021/2022	2070	Highly Concentrated	85.3%
2022/2023	2051	Highly Concentrated	82.8%
2023/2024	2295	Highly Concentrated	85.6%
2024/2025	2387	Highly Concentrated	88.5%
2025/2026	2517	Highly Concentrated	86.7%

Table 6-7 shows the HHI value for committed UCAP MW by LDA by delivery year. The HHI values are calculated by the committed UCAP MW in each delivery year for demand resources.

Table 6-7 HHI value for committed UCAP MW by LDA by delivery year: 2024/2025 and 2025/2026 Delivery Years[30]

Delivery Year	LDA	Committed UCAP MW	HHI Value	HHI Concentration
2024/2025	ATSI	541.0	2839	High
	ATSI-CLEVELAND	141.6	3081	High
	BGE	198.1	3006	High
	COMED	1,554.0	2993	High
	DAY	192.9	3696	High
	DEOK	221.9	3157	High
	DPL-SOUTH	46.0	3515	High
	EMAAC	672.3	2802	High
	MAAC	531.7	2154	High
	PEPCO	160.4	2545	High
	PPL	603.4	2355	High
	PS-NORTH	98.2	2336	High
	PSEG	187.5	2289	High
	RTO	2,915.7	2258	High
2025/2026	ATSI	615.4	2255	High
	ATSI-CLEVELAND	97.3	3262	High
	BGE	168.3	3679	High
	COMED	1,090.5	3119	High
	DAY	141.0	3899	High
	DEOK	159.6	4581	High
	DOM	673.5	3003	High
	DPL-SOUTH	65.0	3876	High
	EMAAC	491.0	3156	High
	MAAC	347.0	2747	High
	PEPCO	135.7	2568	High
	PPL	424.9	2513	High
	PS-NORTH	65.8	2613	High
	PSEG	163.1	2615	High
	RTO	1,627.8	2282	High

30 The RTO LDA refers to the rest of RTO.

Market Performance

Table 6-8 shows the cleared Demand Resource UCAP MW by delivery year. Total cleared demand response UCAP MW in PJM decreased by 1,798.8 MW, or 22.3 percent, from 8,064.7 MW in the 2024/2025 Delivery Year to 6,265.9 MW in the 2025/2026 Delivery Year. The DR percent of capacity decreased by 0.7 percentage points, from 5.2 percent in the 2024/2025 Delivery Year to 4.5 percent in the 2025/2026 Delivery Year.

Table 6-8 Cleared Demand Resource UCAP MW: 2007/2008 through 2025/2026 Delivery Year

	UCAP (MW)		
	DR RPM Cleared	Total RPM Cleared	DR Percent Cleared
2007/2008	127.6	129,409.2	0.1%
2008/2009	559.4	130,629.8	0.4%
2009/2010	892.9	134,030.2	0.7%
2010/2011	962.9	134,036.2	0.7%
2011/2012	1,826.6	134,182.6	1.4%
2012/2013	8,740.9	141,295.6	6.2%
2013/2014	10,779.6	159,844.5	6.7%
2014/2015	14,943.0	161,214.4	9.3%
2015/2016	15,453.7	173,845.5	8.9%
2016/2017	13,265.3	179,773.6	7.4%
2017/2018	11,870.5	180,590.5	6.6%
2018/2019	11,435.4	175,996.0	6.5%
2019/2020	10,703.1	177,064.2	6.0%
2020/2021	9,445.7	174,023.8	5.4%
2021/2022	11,427.7	174,713.0	6.5%
2022/2023	8,866.2	150,465.2	5.9%
2023/2024	8,174.1	150,143.9	5.4%
2024/2025	8,064.7	154,362.5	5.2%
2025/2026	6,265.9	137,733.6	4.5%

Table 6-9 shows zonal monthly capacity market revenue to demand resources for 2025. Capacity market revenue increased in the first three months of 2026 by $321.4 million, 275.5 percent, from $116.6 million in the first three months of 2025 to $438.1 million in the first three months of 2026. The increase in capacity market revenue was a result of the increase in capacity market clearing prices between the 2024/2025 and 2025/2026 Delivery Years. The RTO clearing price in the 2024/2025 BRA was $28.92/MW-Day compared to $269.92/MW-Day in the 2025/2026 BRA.

Table 6-9 Zonal monthly demand resource capacity revenue: January through March, 2026

Zone	January	February	March	Total
ACEC	$342,232	$309,113	$342,232	$993,577
AEP, EKPC	$8,730,837	$7,885,917	$8,730,837	$25,347,592
APS	$4,102,594	$3,705,569	$4,102,594	$11,910,757
ATSI	$6,242,317	$5,638,222	$6,242,317	$18,122,855
BGE	$2,446,970	$2,210,167	$2,446,970	$7,104,107
COMED	$8,268,950	$7,468,729	$8,268,950	$24,006,630
DAY	$1,181,327	$1,067,005	$1,181,327	$3,429,659
DOM	$9,275,482	$8,377,855	$9,275,482	$26,928,820
DPL	$981,511	$886,526	$981,511	$2,849,547
DUKE	$1,335,456	$1,206,219	$1,335,456	$3,877,132
DUQ	$738,183	$666,746	$738,183	$2,143,111
JCPLC	$842,610	$761,067	$842,610	$2,446,286
MEC	$1,137,983	$1,027,855	$1,137,983	$3,303,821
PE	$1,770,232	$1,598,920	$1,770,232	$5,139,384
PECO	$2,470,426	$2,231,352	$2,470,426	$7,172,204
PEPCO	$1,052,969	$951,068	$1,052,969	$3,057,006
PPL	$3,559,375	$3,214,920	$3,559,375	$10,333,670
PSEG	$1,915,325	$1,729,971	$1,915,325	$5,560,622
REC	$19,245	$17,383	$19,245	$55,874
TOTAL	$56,414,025	$50,954,603	$56,414,025	$163,782,653

Product Definition

Pre-Emergency and Emergency Load Response resources must register all resources with a specific response time. The options are to respond within 30, 60 or 120 minutes of a PJM dispatched event. The 30 minute prior notification is the default and applies unless a CSP obtains an exception from PJM due to physical operational limitations that prevent the Demand Resource Registration from reducing load within that timeframe.

Table 6-10 shows the amount of nominated MW and locations by product type and lead time for the 2024/2025 Delivery Year. Nominated MW are Pre-Emergency or Emergency Load Response registrations used to satisfy a CSP's committed MW position for a delivery year. PJM approved 2,681 locations, or

16.1 percent of all locations, which have 3,287.5 nominated MW, or 45.6 percent of all nominated MW, for exceptions to the 30 minute lead time rule for the 2024/2025 Delivery Year.

Table 6-10 Nominated MW and locations by product type and lead time: 2024/2025 Delivery Year

	Pre-Emergency		Emergency			
Lead Type	MW	Percent	MW	Percent	Total	Percent of Total
30 Minutes	3,797.5	96.7%	130.4	3.3%	3,927.9	54.4%
60 Minutes	264.3	89.4%	31.2	10.6%	295.5	4.1%
120 Minutes	2,908.9	97.2%	83.2	2.8%	2,992.0	41.5%
Total	6,970.7	96.6%	244.8	3.4%	7,215.5	100.0%

	Pre-Emergency		Emergency			
Lead Type	Locations	Percent	Locations	Percent	Total	Percent of Total
30 Minutes	13,775	98.8%	165	1.2%	13,940	83.9%
60 Minutes	330	96.5%	12	3.5%	342	2.1%
120 Minutes	2,293	98.0%	46	2.0%	2,339	14.1%
Total	16,398	98.7%	223	1.3%	16,621	100.0%

Table 6-11 shows the amount of nominated MW and locations by product type and lead time for the 2025/2026 Delivery Year. PJM approved 4,926 locations, or 23.4 percent of all locations, which have 4,357.8 nominated MW, or 54.5 percent of all nominated MW, for exceptions to the 30 minute lead time rule for the 2025/2026 Delivery Year.

Table 6-11 Nominated MW and locations by product type and lead time: 2025/2026 Delivery Year

	Pre-Emergency		Emergency			
Lead Type	MW	Percent	MW	Percent	Total	Percent of Total
30 Minutes	3,528.5	96.9%	113.3	3.1%	3,641.8	45.5%
60 Minutes	462.0	92.6%	37.0	7.4%	499.1	6.2%
120 Minutes	3,755.5	97.3%	103.2	2.7%	3,858.8	48.2%
Total	7,746.1	96.8%	253.5	3.2%	7,999.6	100.0%

	Pre-Emergency		Emergency			
Lead Type	Locations	Percent	Locations	Percent	Total	Percent of Total
30 Minutes	15,989	99.1%	141	0.9%	16,130	76.6%
60 Minutes	435	97.1%	13	2.9%	448	2.1%
120 Minutes	4,436	99.1%	42	0.9%	4,478	21.3%
Total	20,860	99.1%	196	0.9%	21,056	100.0%

The alternative notification times are 60 minutes and 120 minutes. The CSP must request an exception in writing, including the reason(s) for the requested exception. Once a location is granted a longer lead time, the resource does not need to resubmit for a longer lead time each delivery year.

The request for an exception must demonstrate one of four defined reasons:[31]

- The manufacturing processes for the Demand Resource Registration require gradual reduction to avoid damaging major industrial equipment used in the manufacturing process, or damage to the product generated or feedstock used in the manufacturing process;
- Transfer of load to backup generation requires time intensive manual process taking more than 30 minutes;
- Onsite safety concerns prevent location from implementing reduction plan in less than 30 minutes; or,
- The Demand Resource Registration is comprised of mass market residential customers or Small Commercial Customers which collectively cannot be notified of a Load Management Event within 30 minutes due to unavoidable communications latency, in which case the requested notification time shall be no longer than 120 minutes.

Table 6-12 shows the nominated MW and locations by product type and lead time of granted lead time exceptions for the 2025/2026 Delivery Year.[32]

Table 6-12 Nominated MW and locations of granted lead time exceptions: 2025/2026 Delivery Year

	60 Minutes		120 Minutes			
Reason	MW	Percent	MW	Percent	Total	Percent
Generation Start Time	50.4	1.2%	475.2	10.9%	525.6	12.1%
Manufacturing Damage	208.6	4.8%	2,257.4	51.8%	2,466.1	56.6%
Safety Problem	240.0	5.5%	1,126.2	25.8%	1,366.3	31.4%
Total	499.1	11.5%	3,858.8	88.5%	4,357.8	100.0%

	60 Minutes		120 Minutes			
Reason	Locations	Percent	Locations	Percent	Total	Percent
Generation Start Time	24	0.5%	1,491	30.3%	1,515	30.8%
Manufacturing Damage	250	5.1%	1,096	22.2%	1,346	27.3%
Safety Problem	174	3.5%	1,891	38.4%	2,065	41.9%
Total	448	9.1%	4,478	90.9%	4,926	100.0%

Prior to participating in the PJM Markets, CSPs must complete a registration in DR Hub which identifies the specific location(s) based on the unique EDC account number that will participate and their associated load reduction capability. Locations are identified by zone, street address and zip code and are not nodal. CSPs must maintain the accuracy of the registration information provided to PJM for each demand resource and each time the CSP registers the location or extends the registration, the CSP must review all information to ensure it is accurate and update as necessary. In order to register demand resources, the CSPs must classify locations according to the location's primary purpose or business use. CSPs first determine if the location's business use falls under one of the following primary categories: Hospitals, Industrial / Manufacturing, Multiple Dwelling Unit, Office Building, Residential, Retail Service, Correctional Facilities, Data Center, Data Center with Crypto Mining, or Schools. In cases where the location does not fit into one of the primary categories, the CSP selects from one of the following categories: Agriculture, Forestry and Fishing, Mining, Transportation, Communications, Electric, Gas and Sanitary Services or Services.[33] PJM had previously not been explicitly identifying demand response associated with data center load in the registration process. PJM was instead, including nominated capacity and load reductions from data centers with crypto mining as a load reduction method under the plug load category. At the April 23, 2025, Markets and Reliability Committee, PJM members endorsed changes to Manual 11 to discontinue this practice. The adopted changes relocated the reference to data centers in the registration process from the load reduction method/plug load section to the business segment section and separately identifies data centers and data centers with crypto mining.[34]

Table 6-13 shows the nominated MW and locations by business segment for the 2025/2026 Delivery Year.

31 OATT Attachment DD-1, Section A.2(a).
32 Data for generation start time and mass market communication categories were combined based on confidentiality rules.
33 "PJM Manual 11: Energy & Ancillary Services Market Operations," § 10.2.2, Rev. 136 (October 1, 2025).
34 See PJM, Consent Agenda B – 1 Manual 11 Revisions - Presentation, <https://www.pjm.com/-/media/DotCom/committees-groups/committees/mrc/2025/20250423/20250423-consent-agenda-b---1--manual-11-revisions---presentation.pdf> (April 23, 2025).

Table 6-13 Nominated MW and locations by business segment: 2025/2026 Delivery Year

Business Segment	Nominated MW (ICAP)	Percent of Total	Locations	Percent of Total
Industrial/Manufacturing	3,882.2	48.5%	3,490	16.6%
Schools	795.2	9.9%	4,028	19.1%
Transportation, Communications, Electric, Gas and Sanitary Services	534.1	6.7%	517	2.5%
Office Building	485.8	6.1%	1,271	6.0%
Services	477.3	6.0%	762	3.6%
Hospitals	421.5	5.3%	365	1.7%
Retail Service	322.9	4.0%	6,753	32.1%
Mining	284.4	3.6%	156	0.7%
Data Center	281.0	3.5%	53	0.3%
Residential	200.3	2.5%	3,113	14.8%
Agriculture, Forestry and Fishing	126.3	1.6%	273	1.3%
Data Center with Crypto Mining	115.2	1.4%	29	0.1%
Multiple Dwelling Unit	37.6	0.5%	206	1.0%
Correctional Facilities	35.7	0.4%	40	0.2%
Total	7,999.6	100.0%	21,056	100.0%

There are two ways to measure the load reductions of emergency demand response resources. The Firm Service Level (FSL) method for the summer period, measures the difference between a customer's peak load contribution (PLC) and its real-time load, multiplied by the loss factor (LF) to account for transmission and distribution line losses.[35] The Guaranteed Load Drop (GLD) method measures the minimum of: the comparison load minus real-time load multiplied by the loss factor; or the PLC minus the real-time load multiplied by the loss factor. The comparison load estimates what the load would have been if PJM did not declare a Load Management Event, similar to a CBL, by using a comparable day, same day, customer baseline, regression analysis or backup generation method. Limiting the GLD method to the minimum of the two calculations ensures reductions occur below the PLC, thus avoiding double counting of load reductions.[36]

With the introduction of the Winter Peak Load (WPL) concept, effective for the 2017/2018 Delivery Year, both the FSL and GLD methods are modified for the non-summer period. The FSL method measures compliance during the non-summer period as the difference between a customer's WPL multiplied by the Zonal Winter Weather Adjustment Factor (ZWWAF) and the loss factor (LF), rather than the PLC, and real-time load, multiplied by the LF. PJM calculates and posts on the PJM website the ZWWAF as the zonal winter weather normalized peak divided by the zonal average of the five coincident peak loads in December through February.[37] The Winter Peak Load is determined based on the average of the Demand Resource customer's specific peak hourly load between hours ending 7:00 EPT through 21:00 EPT on the PJM defined five coincident peak days from December through February two delivery years prior to the delivery year for which the registration is submitted. The Winter Peak Load is adjusted up for transmission and distribution line loss factors (LF) because one MW of load would be served by more than one MW of generation to account for transmission losses. The Winter Peak Load is normalized based on the winter conditions during the five coincident peak loads in winter using the ZWWAF to account for an extreme temperatures or a mild winter. The GLD method measures compliance during the non-summer period as the minimum of: the comparison load minus real-time load multiplied by the loss factor; or the WPL multiplied by the ZWWAF and the LF, rather than the PLC, minus the real-time load multiplied by the LF.[38]

The capacity market is an annual market. A Capacity Performance resource has an annual commitment. Effective with the 2020/2021 Delivery Year, the capacity market design also includes the ability to offer Seasonal Capacity Performance Resources directly into the RPM Auction as an alternative to entering into a commercial arrangement to establish and offer an Aggregate Resource.[39] Capacity Market Sellers may submit sell offers of either Summer Period Capacity Performance Resources or Winter Period Capacity Performance Resources and the auction clearing optimization algorithm is designed to clear equal quantities of offsetting seasonal capacity sell offers thereby creating an annual capacity commitment by matching a Summer Period Capacity Performance Resource with a Winter Period Capacity Performance Resource. Load is allocated capacity obligations based on the annual peak load which

35 Real-time load is hourly metered load.
36 See 135 FERC ¶ 61,212 (2011).
37 "PJM Manual 18: PJM Capacity Market," § 4.3.7, Rev. 62 (December 17, 2025).
38 "PJM Manual 18: PJM Capacity Market," § 8.7A, Rev. 62 (December 17, 2025).
39 An Aggregate Resource is created by a Capacity Market Seller that owns or controls one or more Capacity Storage Resources, Intermittent Resources, Demand Resources or Environmentally Limited Resources by submitting a Sell Offer which represents the aggregated Unforced Capacity value of such resources, where such Sell Offer is considered to be located in the smallest modeled LD common to the aggregated resources.

is a summer load. The amount of capacity MW allocated to load does not vary based on winter demand. The principle is that a customer's actual use of capacity should be compared to the level of capacity that a customer is required to pay for. Capacity costs are allocated to LSEs by PJM based on the single coincident peak load method. In PJM, the single coincident peak occurs in the summer.[40] LSEs generally allocate capacity costs to customers based on the five coincident peak method.[41] The allocation of capacity costs to customers uses each customer's PLC. Customers pay for capacity based on the PLC, not the WPL. If an end customer has 3 MW of load during the coincident peak load hour, but only 1 MW during the coincident winter peak load hour, the End Use Customer must pay for 3 MW of capacity for the entire delivery year, but can only participate as a 1 MW demand response resource. Using PLC to measure compliance for the entire delivery year would allow the customer to fully participate as a 3 MW demand response resource. FERC allowed the use of the WPL for calculating compliance for non-summer months effective June 1, 2017.[42] The MMU recommends setting the baseline for measuring capacity compliance under summer and winter compliance at the customer's PLC, similar to GLD, to avoid double counting, to avoid under counting and to ensure that a customer's purchase of capacity is calculated correctly. The FSL and GLD equations for calculating load reductions are:

$$FSL\ Compliance_{Summer} = PLC - (Load \cdot LF)$$

$$FSL\ Compliance_{Non-Summer} = (WPL \cdot ZWWAF \cdot LF) - (Load \cdot LF)$$

$$GLD\ Compliance_{Summer} = Minimum\{(comparison\ load - Load) \cdot LF; PLC - (Load \cdot LF)\}$$

$$GLD\ Compliance_{Non-Summer} = Minimum\{(comparison\ load - Load) \cdot LF; (WPL \cdot ZWWAF \cdot LF) - (Load \cdot LF)\}$$

For Demand Resources prior to the 2025/2026 Delivery Year, PJM calculated UCAP as the product of the FPR and the Demand Resource's Nominated Value, which depends on the peak load contribution of customers on the Demand Resource registration and their committed Firm Service Level or Guaranteed Load Drop.[43]

40 OATT Attachment DD § 5.11.
41 OATT Attachment M-2.
42 162 FERC ¶ 61,159 (2018).
43 See PJM, Intra-PJM Tariffs, RAA, Schedule 6 (18.0.0), § 6.I.

The current accreditation practice for Demand Resources assumes they provide 100 percent performance at any time they are required to perform. Beginning with the 2025/2026 Delivery Year, PJM instituted an ELCC approach for generation and emergency demand response resources. For Demand Resources, PJM calculates Accredited UCAP as the product of the resource's Nominated Value and its ELCC Class Rating. Unlike generation, PJM does not apply a resource specific performance adjustment for Demand Resources. The Demand Resource availability window, defined in the RAA for Annual Demand Resources and Summer-Period Demand Resources, does not align with the projected hours with a loss of load risk in the winter period.[44] The ELCC class rating for Demand Resources for the 2025/2026 BRA is 76 percent.[45]

PJM makes several unsupported assumptions when calculating ELCC for demand response resources. The PJM ELCC calculations do not account for the actual historical performance of DR in same way as thermal resources. PJM analysis showed that the ELCC reduction capability is overstated compared to the metered DR reduction capability.[46] This overstatement of performance is consistent with the observed performance of DR during Winter Storm Elliott. There was a significant disparity between the reported expected reduction capability provided by the CSPs and the actual observed energy reduction during Winter Storm Elliott. As a general matter, these resources are rarely used.

Beginning in May 2024, the MIC worked on a problem statement and issue charge regarding the alignment of demand response capacity availability hours with periods of reliability risk.[47] PJM proposed to expand the window to all hours. PJM also proposed to use coincident peak demand rather than the sum of noncoincident peak demands to measure the level of demand resources. The MMU supported the extension of availability to all hours, consistent with all other capacity resources. The MMU supported the proposal to measure all

44 See "Responses to Deficiency Letter – Capacity Market Reforms to Accommodate the Energy Transition," ER24-99-001. (December 1, 2023), at p 28.
45 See "*2025-2026 BRA ELCC Class Ratings,*" <https://pjm.com/-/media/planning/res-adeq/elcc/2025-26-bra-elcc-class-ratings.ashx> (March 13, 2024).
46 See PJM, DR Availability Window: Additional DR ELCC Information, <https://pjm.com/-/media/committees-groups/committees/mic/2024/20240807/20240807-item-08b---pjm-dr-education.ashx> (August 7, 2024).
47 See *Approved Minutes from the Markets & Reliability Committee*, <https://pjm.com/-/media/committees-groups/committees/mrc/2024/20240627/20240627-consent-agenda-a---draft-mrc-minutes---05222024.ashx>.

DR for the same coincident peak demand hour as a more accurate measure of the level of actual DR potential rather than the overstatement that has resulted from adding together all the DR from individual non coincident peak hours.

PJM also proposed to increase the ELCC derating factor from 76 percent to 94 percent, an increase of 24 percent in the value of demand resource MW. PJM's proposed ELCC value for DR is not consistent with the method PJM uses for generation resources. PJM's proposed ELCC for DR is based on assumed behavior and not based on the actual performance of demand resources during the same high EUE (expected unserved energy) hours used for other capacity resources. The current ELCC value for demand response is already overstated. As currently demand resources are inferior resources in the capacity market and the ELCC values, both existing and proposed, significantly overstate their contribution to reliability. The demand resources are rarely used. While PJM may call on demand resources as part of its emergency actions, there are no PJM rules governing the overall commitment and dispatch of demand resources as there are for all other capacity resources.[48] Demand resources do not have a must offer obligation in the energy market as all other capacity resources do. PJM rules do not indicate if, when and how demand resources should be called on for nonemergency events. PJM rules do not require the use of demand resources under defined conditions. PJM rules do not require that demand resources be called on during emergency events but leave all emergency actions to the discretion of PJM dispatchers. The proposed changes would increase the value of demand resources by almost a billion dollars ($880.7 M) without any actual change in the physical reality and without the type of detailed analysis applied to other capacity resources.[49] The proposed changes would simply pay demand response more for capacity without any increase in use and without any rules governing when demand response can or will be used for economic reasons and without a must offer obligation in the energy or capacity markets, and without any market power mitigation rules, without resource specific performance adjustments, and without addressing the fact that demand side performance metrics simply ignore increases in load above the WPL when called. PJM did not propose consistent changes to the treatment of demand resources in the summer. PJM proposed to make these changes to the ELCC value of demand response resources while ignoring significant issues with the treatment of other resource technologies. The result of this administrative change would also be to affect the ELCC of other classes and to make it appear that PJM is more reliable than it is. PJM filed these proposed changes on March 6, 2025, in Docket No. ER25-1525-000.[50] The IMM filed an answer and motion for leave to answer on April 14, 2025.[51] On May 5, 2025, in Docket No. ER25-1525-000, FERC accepted PJM's section 205 proposal to revise the RAA, effective with the 2027/2028 Delivery Year, that extends the Demand Resource availability window to 24 hours a day throughout the year and revises the definition of Winter Peak Load used in calculating Demand Resources' Winter Nominated Value in PJM's ELCC method, effective May 6, 2025.[52]

Table 6-14 shows the MW registered by measurement and verification method and by technology type for the 2025/2026 Delivery Year. For the 2025/2026 Delivery Year, 99.75 percent of the MW use the FSL method and 0.25 percent of the MW use the GLD measurement and verification method.

48 See PJM Manual 13: Emergency Operations, §2.3.2. Rev. 97 (November 20, 2025).

49 See PJM, DR Availability Window – IMM Proposal, <https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2025/20250205/20250205-item-02-2---dr-availability-window---imm-proposal.pdf> (February 5, 2025).

50 See "Proposal to Extend Demand Resource Availability Window and Revise Calculation of Demand Resource Winter Nominated Value," Docket No. ER25-1525-000 (March 6, 2025).

51 See "Answer and Motion for Leave to Answer," Docket No. ER25-1525-000 (April 14, 2025).

52 191 FERC ¶ 61,103

Table 6-14 Nominated MW by each demand response method: 2025/2026 Delivery Year

	Technology Type								
Measurement and Verification Method	On-site Generation MW	HVAC MW	Refrigeration MW	Lighting MW	Manufacturing MW	Water Heating MW	Other, Batteries or Plug Load MW	Total	Percent by type
Firm Service Level	1,258.3	1,892.9	210.8	792.0	3,659.3	24.4	141.6	7,979.3	99.75%
Guaranteed Load Drop	5.1	1.1	0.0	0.0	14.1	0.0	0.0	20.3	0.25%
Total	1,263.4	1,894.0	210.8	792.0	3,673.4	24.4	141.6	7,999.6	100.0%
Percent by method	15.8%	23.7%	2.6%	9.9%	45.9%	0.3%	1.8%	100.0%	

Table 6-15 shows the fuel type used in the onsite generators for the 2025/2026 Delivery Year in the emergency and pre-emergency programs. For the 2025/2026 Delivery Year, 1,263.4 MW of the 7,999.6 nominated MW, 15.8 percent, used onsite generation. Of the 1,263.4 MW, 84.5 percent used diesel and 15.5 percent used natural gas, gasoline, oil, propane or waste products. Some DR registrations reflect a participant's reliance on behind the meter generation having environmental restrictions that limit the resource's ability to operate only in emergency conditions. Demand resources relying on behind the meter generation having environmental restrictions limiting the resource's ability to operate only in emergency conditions must register as emergency DR. EPA regulations require that Reciprocating Internal Combustion Engines (RICE) that do not meet EPA emissions standards (stationary emergency RICE) may operate for only 100 hours per year and only to provide emergency DR during an Energy Emergency Alert 2 (EEA2), or if there are five percent voltage/frequency deviations. PJM does not prevent emergency stationary RICE that does not meet emissions standards from participating in PJM markets as DR. Some emergency stationary RICE that does not meet emissions standards are now included in DR portfolios. PJM's DR Hub does not explicitly identify Reciprocating Internal Combustion Engines (RICE) generators, only whether it is an internal combustion engine. For the 2025/2026 Delivery Year, of the 253.5 MW registered as generation backed emergency DR, 251.4 MW, or 19.9 percent of all onsite generation, are backed by internal combustion engines. 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.

Table 6-15 Onsite generation fuel type (MW): 2025/2026 Delivery Year

	2025/2026	
Fuel Type	MW	Percent
Diesel	1,068.1	84.5%
Natural Gas, Gasoline, Oil, Propane, Waste Products	195.3	15.5%
Total	1,263.4	100.0%

Table 6-16 shows the MW registered by measurement and verification method and by technology type for the 2024/2025 Delivery Year. For the 2024/2025 Delivery Year, 99.99 percent use the FSL method and 0.01 percent use the GLD measurement and verification method.

Table 6-16 Nominated MW by each demand response method: 2024/2025 Delivery Year

	Technology Type								
Measurement and Verification Method	On-site Generation MW	HVAC MW	Refrigeration MW	Lighting MW	Manufacturing MW	Water Heating MW	Batteries and Plug Load MW	Total	Percent by type
Firm Service Level	1,050.5	1,731.0	192.5	663.3	3,438.5	22.3	116.5	7,214.7	99.99%
Guaranteed Load Drop	0.0	0.7	0.0	0.0	0.1	0.0	0.0	0.8	0.01%
Total	1,050.5	1,731.7	192.5	663.3	3,438.6	22.3	116.5	7,215.5	100.0%
Percent by method	14.6%	24.0%	2.7%	9.2%	47.7%	0.3%	1.6%	100.0%	

Table 6-17 shows the fuel type used in the onsite generators for the 2024/2025 Delivery Year in the emergency and pre-emergency programs. For the 2024/2025 Delivery Year, 1,050.5 MW of the 7,215.5 nominated MW, 14.6 percent, use onsite generation. Of the 1,050.5 MW, 84.1 percent use diesel and 15.9 percent use natural gas, gasoline, oil, propane or waste products.

Table 6-17 Onsite generation fuel type (MW): 2024/2025 Delivery Year

	2024/2025	
Fuel Type	MW	Percent
Diesel	883.5	84.1%
Natural Gas, Gasoline, Oil, Propane, Waste Products	167.0	15.9%
Total	1,050.5	100.0%

Emergency and Pre-Emergency Event Reported Compliance

Capacity resources measure performance nodally, except for demand resources. PJM cannot dispatch demand resources by node with the current rules because demand resources are not registered to a node. Demand resources can be dispatched by subzone only if the subzone is defined before dispatch. Aggregation rules allow a demand resource that incorporates many small End Use Customers to span an entire zone, which is inconsistent with nodal dispatch.

Subzonal dispatch became mandatory for emergency demand resources in the 2014/2015 Delivery Year.[53] A subzone is defined by zip code, not by nodal location. If a registration has any location in the dispatched subzone, as defined by the zip code of the enrolled End Use Customer's address, the entire registration must respond. There are currently nine defined dispatchable subzones in PJM: APS_EAST, DOM_CHES, DOM_YORKTOWN, AECO_ENGLAND, JCPL_REDBANK, DOM_ASHBURN, DOM_DCA, DOM_PRINWILM and AEP_MARION.[54] The AEP_MARION subzone was added as a result of the June 14-16, 2022, performance assessment event in the Columbus, Ohio area of the AEP Zone.

PJM can remove a defined subzone, and make changes to the subzone, at their discretion. Subzones should not be removed once defined, as the subzone may need to be dispatched again in the future. The METED_EAST, PENELEC_EAST, PPL_EAST and DOM_NORFOLK Subzones were removed by PJM. 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.

The subzone design and closed loop interfaces are related. PJM implemented closed loop interfaces with the stated purpose of improving the incorporation of reactive constraints into energy prices and to allow emergency DR to set price.[55] PJM applies closed loop interfaces so that it can use units needed for reactive support to set the energy price when they would not otherwise set price under the LMP algorithm. PJM also applies closed loop interfaces so that it can use emergency DR resources to set the real-time LMP when DR would not otherwise set price under the fundamental LMP logic. Of the 20 closed loop interface definitions, 11 (55 percent) were created for the purpose of

53 OATT Attachment DD, § 11.

54 See "Load Management Subzones," <https://www.pjm.com/-/media/markets-ops/demand-response/subzone-definition-workbook.ashx> (Accessed January 13, 2023).

55 See PJM/Alstom. "Approaches to Reduce Energy Uplift and PJM Experiences," presented at the FERC Technical Conference: Increasing Real-Time and Day-Ahead Market Efficiency Through Improved Software, Docket No. AD10-12-006 (June 23, 2015) <http://www.ferc.gov/june-tech-conf/2015/presentations/m2-3.pdf>.

allowing emergency DR to set price.[56] The closed loop interfaces created for the purpose of allowing emergency DR to set price are located in the Rest of RTO, MAAC, EMAAC, SWMAAC, DPL-SOUTH, ATSI, ATSI-CLEVELAND and BGE LDAs. These interfaces correspond to LDAs as defined in RPM.[57]

Demand resources can be dispatched for voluntary compliance during any hour of any day, but dispatched resources are not measured for compliance outside of the mandatory compliance window for each demand product. This will change beginning in the 2027/2028 Delivery Year when the mandatory compliance window will expand to 24 hours per day. A demand response event during a product's mandatory compliance window also may not result in a compliance score. When demand response events occur for partial hours under 30 minutes, the event is not measured for compliance.

Demand resources currently estimate five minute compliance with an hourly interval meter during PAIs. To accurately measure compliance on a five minute basis, a five minute interval meter is required. All other capacity resources require five minute interval meters, and demand resources should be no different. Demand resources are paid based on the average performance by registration for the duration of a demand response event. Demand response should measure compliance on a five minute basis to accurately report reductions during demand response events. Measuring compliance on a five minute basis would provide accurate information to the PJM system. The MMU recommends demand response event compliance be calculated on a five minute basis for all capacity resources and that the penalty structure reflect five minute compliance.[58]

Under the capacity performance design of the capacity market, compliance for potential penalties is measured for DR only during performance assessment intervals (PAI).[59]

The MMU recommended that demand response resources be treated as economic resources like all other capacity resources and therefore that the dispatch of demand response resources not automatically trigger a performance assessment interval (PAI) for CP compliance. Emergencies should be triggered only when PJM has exhausted all economic resources including demand response resources. For the first seven months of 2023, PJM declared an emergency if pre-emergency or emergency demand response were dispatched. But in an order issued July 28, 2023, effective July 30, 2023, FERC approved proposed 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).[60] Table 6-18 shows the amount of nominated demand response MW, the required reserve margin and actual reserve margin for the 2024/2025 and 2025/2026 Delivery Years. There are 8,137.5 nominated MW of demand response for the 2025/2026 Delivery Year, 32.1 percent of the required reserve margin and 32.4 percent of the actual reserve margin for the 2025/2026 Delivery Year.[61]

Table 6-18 Demand response nominated MW compared to reserve margin: 2024/2025 and 2025/2026 Delivery Years[62]

Delivery Year	Demand Response Nominated MW	Required Reserve Margin	Demand Response Percent of Required Reserve Margin	Actual Reserve Margin	Demand Response Percent of Actual Reserve Margin
2024/2025	7,220.0	21,398.4	33.7%	24,856.8	29.0%
2025/2026	8,137.5	25,381.0	32.1%	25,116.0	32.4%

PJM will dispatch demand resources by zone or subzone, or within a PAI area. When PJM dispatches all demand resources in multiple connecting zones, PJM further degrades the nodal design of electricity markets. In that case, PJM allows compliance to be measured across zones within a compliance aggregation area (CAA).[63] [64] A CAA is an electrically connected area that has

56 See the *2018 Annual State of the Market Report for PJM*, Volume 2: Section 4, Energy Uplift, for additional information regarding all closed loop interfaces and the impacts to the PJM markets.
57 "PJM Manual 18: PJM Capacity Market," § 2.3.1, Rev. 62 (December 17, 2025).
58 "PJM Manual 18: PJM Capacity Market," § 8.7A, Rev. 62 (December 17, 2025).
59 OATT § 1 (Performance Assessment Hour).
60 See "Order Accepting Tariff Revisions Subject to Condition," Docket No. ER23-1996-000 (July 28, 2023).
61 See *2025 Annual State of the Market Report for PJM*, Section 5: Capacity Market, Table 5-7.
62 Nominated MW totals are Demand Response ICAP corresponding to Demand Response UCAP cleared in RPM auctions for each delivery year. The total nominated MW values do not reflect replacement transactions.
63 CAA is "a geographic area of Zones or sub-Zones that are electrically contiguous and experience for the relevant Delivery Year, based on Resource Clearing Prices of, for Delivery Years through May 31, 2018, Annual Resources and for the 2018/2019 Delivery Year and subsequent Delivery Years, Capacity Performance Resources, the same locational price separation in the Base Residual Auction, the same locational price separation in the First Incremental Auction, the same locational price separation in the Second Incremental Auction, or the same locational price separation in the Third Incremental Auction." OATT § 1.
64 PJM. "Manual 18: Capacity Market," § 8.7.2, Rev. 62 (December 17, 2025).

the same capacity market price. This changes the way CSPs dispatch resources when multiple electrically contiguous areas with the same RPM clearing prices are dispatched. The compliance rules determine how CSPs are paid and thus create incentives that CSPs will incorporate in their decisions about how to respond to PJM dispatch. The multiple zone approach is even less locational than the zonal and subzonal approaches and creates larger mismatches between the locational need for the resources and the actual response. If multiple zones within a CAA are called by PJM, a CSP will dispatch the least cost resources across the zones to cover the CSP's obligation. This can result in more MW dispatched in one zone that are locationally distant from the relief needed and no MW dispatched in another zone, yet the CSP could be considered 100 percent compliant and pay no penalties. More locational deployment of load management resources would improve efficiency. With full implementation of capacity performance, demand response will be dispatched by registrations within an area for which an Emergency Action is declared by PJM. PJM does not have the nodal location of each registration, meaning PJM will need to guess as to the useful demand response registration by registered location. The MMU recommends that demand resources be required to provide their nodal location. Nodal dispatch of demand resources would be consistent with the nodal dispatch of generation.

Definition of Compliance

PJM's reporting of load management events overstates the performance of demand side capacity resources. Limiting reported compliance to only positive values incorrectly reports compliance. Settlement locations with a negative load reduction value (load increase) are not included in compliance reporting by PJM within registrations or within demand response portfolios. A resource that has load above their PLC during a demand response event has a negative performance value. But PJM does not include the negative performance values in the net performance calculation. PJM limits reported compliance shortfall values to zero MW.

The MMU recommends that PJM correctly report compliance for demand side capacity resources to include negative values above PLC when calculating event compliance across hours and registrations.[65]

Emergency demand response resources that are also registered as economic resources have a calculated CBL for the emergency event days. Demand resources that are not registered as economic resources use the three day CBL type with the symmetrical additive adjustment for measuring energy reductions without the requirements of a Relative Root Mean Squared Error (RRMSE) Test required for all economic resources.[66] The CBL must use the RRMSE test to verify that it is a good approximation for real-time load usage.

The MMU recommends that PJM Manual 11 be revised to require, rather than recommend, that the RRMSE test be applied to all demand resources with a CBL.[67]

The CBL for a customer is an estimate of what load would have been if the customer had not responded to LMP and reduced load. The difference between the CBL and real-time load is the energy reduction. When load responds to LMP by using a behind the meter generator, the energy reduction should be capped at the generation output. Any additional energy reduction is a result of inaccuracy in the CBL estimate rather than an actual reduction. The MMU recommends capping demand reductions based entirely on behind the meter generation at the lower of the generator's economic maximum or actual generation output.

An extreme example makes clear the fundamental problems with the use of measurement and verification methods to define the level of power that would have been used but for the DR actions, and the payments to DR customers that result from these methods. The current rules for measurement and verification for demand resources make a bankrupt company, a customer that no longer exists due to closing of a facility or a permanently shut down company, or a company with a permanent reduction in peak load due to a partial closing of a facility, an acceptable demand response customer under some interpretations

65 See "Market Monitor Report," MC Webinar <https://pjm.com/-/media/committees-groups/committees/mc/2023/20230620-webinar/item-04---imm-report.ashx> (Accessed July 6, 2023).
66 157 FERC ¶ 61,067 (2016).
67 PJM. "Manual 11: Energy & Ancillary Services Market Operations," § 10.2.5, Rev. 136 (October 1, 2025).

of the tariff, although it is the view of the MMU that such customers should not be permitted to be included as registered demand resources. Companies that remain in business, but with a substantially reduced load, can maintain their pre-bankruptcy FSL (firm service level to which the customer agrees to reduce in an event) commitment, which can be greater than or equal to the post-bankruptcy peak load. The customer agrees to reduce to a level which is greater than or equal to its new peak load after bankruptcy. When demand response events occur the customer would receive credit for 100 percent reduction, even though the customer took no action and could take no action to reduce load. This problem exists regardless of whether the customer is still paying for capacity. To qualify and participate as a demand resource, the customer must have the ability to reduce load. “A participant that has the ability to reduce a measurable and verifiable portion of its load, as metered on an EDC account basis.”[68] Such a customer no longer has the ability to reduce load in response to price or a PJM demand response event. CSPs in PJM have and continue to register bankrupt customers as emergency or pre-emergency load response customers. PJM finds acceptable the practice of CSPs maintaining the registration of customers with a bankruptcy related reduction in demand that are unable, as a result, to respond to emergency events. Three proposals that included language to remove bankrupt customers from a CSP’s portfolio failed at the June 7, 2017, Market Implementation Committee.[69] The registered customers that are bankrupt and the amount of registered MW cannot be released for reasons of confidentiality.

The metering requirement for demand resources is outdated, and has not kept up with the changes to PJM’s market design. PJM moved to five minute settlements, but the metering requirement for demand resources remained at an hourly interval meter. It is impossible to measure energy usage on a five minute basis using an hourly interval meter. PJM will estimate real-time usage by prorating the hourly interval meter and assume if load is less than the CBL, that the reduction occurred during the required dispatch window. The meter reading is not telemetered to PJM in real time. The resource is allowed up to 60 days to report the data to PJM.[70] The MMU recommends that PJM adopt the ISO-NE five-minute metering requirements in order to ensure that dispatchers 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 so that they can accurately measure compliance and that data be provided to PJM within 24 hours.[71]

On September 19, 2024, the Commission issued an order denying the complaint by Enerwise Global Technologies seeking to use statistical sampling for measuring demand response performance when interval metering is available.[72] Commissioner Chang concurred with the Commission’s determination and agreed that using actual metered interval data is the ideal method to measure and verify performance for demand-side resources. Commissioner Chang further noted that it is essential that resources that are procured and compensated in the markets actually deliver on their reliability and economic commitments.[73]

On October 8, 2025, a complaint was filed by Voltus, Inc. and Mission:data requesting the Commission require that PJM allow CSPs to use statistical sampling for residential customers that have interval meters.[74] On October 28, 2025, the MMU filed comments pointing out that using statistical sampling when actual interval meter data is available would degrade PJM’s ability to accurately measure the MW of capacity available and the actual performance of that capacity and therefore degrade PJM’s ability to maintain resource adequacy and to correctly determine efficient capacity market prices through supply and demand in the market. [75]

68 OA Schedule 1 § 8.2.
69 There was one proposal from PJM, one proposal from a market participant and one proposal from the MMU. See *Approved Minutes from the Market Implementation Committee*, <http://www.pjm.com/-/media/committees-groups/committees/mic/20170607/20170607-minutes.ashx>.
70 “PJM Manual 11: Energy & Ancillary Services Market Operations,” § 10.4.1, Rev. 136 (October 1, 2025).
71 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.
72 See “Order Denying Complaint re Enerwise Global Technologies, LLC v. PJM Interconnection,” EL23-104-000 (July 28, 2023).
73 *Id*, Commissioner Chang Statement Concurring at 1.
74 Voltus, Inc. and Mission:data v. PJM Interconnection, L.L.C., Complaint of Voltus, Inc. and Mission:data, Docket No. EL26-4-000 (Oct. 8, 2025).
75 See “Comments of the Independent Market Monitor for PJM,” Docket No. EL26-4-000 (October 28, 2025).

When demand resources are not dispatched during a mandatory response window, each CSP must test their portfolio to the levels of capacity commitment, but the testing requirements have been inadequate.[76]

For the 2023/2024 Delivery Year and subsequent delivery years, if a Demand Resource registration is not dispatched by PJM for a Load Management event in a delivery year, then the registration must be tested for a two-hour period between the hours of 11:00 EPT and 18:00 EPT of a non-NERC holiday weekday during June through October or November through March of the relevant delivery year, where the date and time are selected by PJM.[77] All registrations in a zone are tested simultaneously for two hours for each product type. Registration performance is calculated as the two hour average reduction.

If less than 25 percent (by MW) of a CSP's total Demand Resources in a zone fail the test, the CSP may conduct re-tests limited to all registrations that failed to meet their seasonal nominated ICAP in the prior test, provided that such re-test(s) must be during the same season, at the same time of day and under approximately the same weather conditions as the prior test. If 25 percent or more (by MW) of a CSP's Demand Resources fail the test, the CSP may request PJM to schedule a one time retest limited to all registrations that failed to meet their seasonal nominated ICAP in the prior test. The request must be made before the 46th day after the test. PJM will select the date and time of the retest during the same season. For the initial PJM scheduled test, PJM schedules, on an alternating basis, one test during June through October or November through March for each delivery year that a test is required. On the first business day of a week, PJM provides notice of all zones to be tested during the following two week test window. The test window opens the first business day of the week following the notice. By 10:00 EPT the day before the test, PJM posts on its website, and notifies the CSPs directly, the test date and zones.[78] On the test date, CSPs are notified of the start time of the test through the same notification protocol used for an actual event. For any scheduled retest by PJM, by 10:00 EPT the day before the retest, PJM will posts on its website, and notifies the CSPs directly, the retest date. On the retest date, CSPs are notified of the start time of the retest through the same notification protocol used for an event.

76 The mandatory response time for Capacity Performance DR is June through October and the following May between 10:00AM to 10:00PM EPT and November through April between 6:00AM through 9:00PM EPT. *See* PJM. "Manual 18: PJM Capacity Market," Rev. 62 (December 17, 2025).

77 "PJM Manual 18: PJM Capacity Market," § 8.7, Rev. 62 (December 17, 2025).

78 See "Demand Response Test Schedule," <https://pjm.com/markets-and-operations/demand-response/demand-response-test-schedule> (Accessed July 18, 2023).

While the testing revisions implemented with the 2023/2024 Delivery Year are an improvement, 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.

Beginning in the 2024/2025 Delivery Year and subsequent delivery years, CSPs may elect to use performance data from a Load Management event that was not subject to a Non-Performance Assessment (a non-PAI LM event) as performance data for a PJM zonal test event.[79] Elections are made on or after June 1 and no later than July 14 after the delivery year in the DR Hub system. Data required for compliance evaluation must be submitted no later than July 14 after the delivery year. Only one event result (either test event or non-PAI LM event) for each end-use customer site will be used in the zonal test evaluation. The duration of the non-PAI LM event must be at least 30 minutes of a clock hour. The election of non-PAI LM events to be used as zonal test performance will be done at registration lead time level. The non-PAI LM event must have occurred in the same season as the PJM scheduled test. For purposes of this election, the calculated reduction value for a registration in the non-PAI LM event is the average of the registration's hourly reductions within the product period hourly window.

The ability for test performance to be a substitute for event performance, coupled with the absence of nonperformance penalties, weakens the incentive to perform during non-PAI events. Emergency demand response resources have the same obligation to perform when called upon, regardless of whether the dispatch event occurs as part of a PAI or not.[80] There is no reason therefore to allow CSPs the optionality of testing in lieu of using non-PAI event performance.

79 "PJM Manual 18: PJM Capacity Market," § 8.7, Rev. 62 (December 17, 2025).

80 OATT Attachment K, § 8.5.

Table 6-19 shows the test penalties by delivery year by product type for the 2021/2022 Delivery Year through the 2024/2025 Delivery Year. The shortfall MW are calculated for each CSP by zone. The weighted rate per MW is the average penalty rate paid per MW. Testing shortfalls increased dramatically beginning with the 2023/2024 Delivery Year. The testing shortfall for the 2024/2025 Delivery Year increased by 134 percent compared to the 2023/2024 Delivery Year. Total Load Management Test Compliance penalties were 15.5 percent of total DR capacity revenues in the 2024/2025 Delivery Year.

The daily load management test failure charge rate for a zonal testing shortfall is equal to the provider's weighted daily revenue rate in such zone plus the greater of 0.20 times the provider's weighted daily revenue rate in such zone, or $20/MW-day. A daily load management test failure charge, equal to the net testing shortfall in the zone times the daily load management test failure charge rate, is applied for each day in the delivery year that the resource was committed. The load management test failure charge is assessed in the August monthly bill, issued in September, after the conclusion of the delivery year.[81] The ex-post nature of the load management test penalty, coupled with a high test failure rate, creates the potential for credit issues. Planned demand resource positions in RPM have a collateral requirement only until such time that a nominated MW quantity of customers are registered in DRHUB sufficient to cover the RPM zonal MW quantity committed.[82] These registrations occur prior to the start of the delivery year. Following the delivery year, at the time the testing penalty is levied, these resources are no longer collateralized. Providers subject to test failure penalties would nonetheless be subject to a retroactive disgorgement of revenues proportional to the shortfall quantity plus the higher of 20 percent of their weighted daily revenue rate or $20/MW-day.

Table 6-19 Test penalties by delivery year: 2021/2022 through 2024/2025 Delivery Years

	2021/2022			2022/2023			2023/2024			2024/2025		
Product Type	Shortfall MW	Weighted Rate per MW	Total Penalty	Shortfall MW	Weighted Rate per MW	Total Penalty	Shortfall MW	Weighted Rate per MW	Total Penalty	Shortfall MW	Weighted Rate per MW	Total Penalty
Capacity Performance	23.1	$176.79	$1,487,430	7.1	$97.07	$250,346	391.4	$56.45	$8,087,631	933.4	$53.50	$18,225,318

When describing overall test performance, PJM nets the over and under performance of all resources. Netting overstates the performance and capability of the underlying resources. A resource that tests short of its RPM commitment is subject to a penalty. That penalty is offset neither by the over performance of the provider's other resources nor that of other provider's resources. Additionally, during an actual dispatch event, a resource is only required to perform up to its RPM commitment to avoid penalties. While a resource may demonstrate excess capability during testing, there is no obligation for that capability to be provided during an actual event.

Test results for the 2024/2025 Delivery Year when netted, demonstrate an overall capability of 103 percent of the RPM commitment. Underlying this are 933 MW UCAP of testing deficiencies assessed to individual resources. Testing results for the 2024/2025 Delivery Year also showed a marked difference in performance between CSP and EDC or utility-operated programs. As a general matter, the overall over performance of the EDC program resources offset the overall under performance of non-utility providers in the 2024/2025 Delivery Year. Table 6-20 contrasts the testing performance of resources from utility versus non-utility providers for the 2024/2025 Delivery Year.

81 "PJM Manual 18: PJM Capacity Market," § 9.1.6, Rev. 62 (December 17, 2025).
82 "PJM Manual 18: PJM Capacity Market," § 4.8.2, Rev. 62 (December 17, 2025).

Table 6-20 Testing Performance: CSP vs EDC Providers

Provider Type	RPM Commitment MW UCAP	Test Performance MW UCAP	Percent
CSP	6,782.6	6,396.5	94%
EDC	920.4	1,540.8	167%
Overall	7,703.1	7,937.3	103%

Emergency and Pre-Emergency Load Response Energy Payments

Emergency and pre-emergency demand response dispatched during a load management event by PJM are eligible to receive emergency energy payments if registered under the full program option. The full program option includes an energy payment for load reductions during a pre-emergency or emergency event for demand response events and capacity payments.[83] There are 98.7 percent of nominated MW for the 2025/2026 Delivery Year registered under the full program option. There are 1.3 percent of nominated MW for the 2025/2026 Delivery Year registered as capacity only option. Demand resources clear the capacity market like all other capacity resources and the dispatch of demand resources should not trigger a scarcity event. The strike price is set by the CSP before the delivery year starts and cannot be changed during the delivery year. The demand resource energy payments are equal to the higher of hourly zonal LMP or the strike price energy offer made by the participant, including a dollar per MWh minimum dispatch price and an associated shutdown cost. Demand resources should not be permitted to offer above $1,000 per MWh without cost justification or to include a shortage penalty in the offer. FERC has stated clearly that demand resources in the capacity market must verify costs above $1,000 per MWh, unless they are capacity only: "We clarify, however, that reforms adopted in this Final Rule, which provide that resources are eligible to submit cost-based incremental energy offers in excess of $1,000/MWh and require that those offers be verified, do not apply to capacity-only demand response resources that do not submit incremental energy offers in energy markets."[84] PJM interprets the scarcity pricing rules to allow a maximum DR energy price of $1,849 per MWh for the 2021/2022 Delivery Year.[85] [86] Demand resources registered with the full option should be required to verify energy offers in excess of $1,000 per MWh. PJM does not require such verification.[87] 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.

Shutdown costs for demand response resources are not adequately defined in Manual 15. PJM's Cost Development Subcommittee (CDS) approved changes to Manual 15 to eliminate shutdown costs for demand response resources participating in the synchronized reserve market, but not demand resources or economic resources.[88]

Table 6-21 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices for the 2024/2025 Delivery Year. The majority of participants, 83.3 percent of locations and 52.8 percent of nominated MW, had a minimum dispatch price between $1,550 and $1,849 per MWh, the maximum price allowed for the 2024/2025 Delivery Year. Almost all registrations, 99.7 percent of locations and 98.1 percent of nominated MW have a dispatch price above $1,000 per MWh. The shutdown cost of resources with $1,000 to $1,275 per MWh strike prices had the highest average at $137.74 per location and $109.14 per nominated MW.

Table 6-21 Distribution of registrations and associated MW in the full option across ranges of minimum dispatch: 2024/2025 Delivery Year

Ranges of Strike Prices ($/MWh)	Locations	Percent of Total	Nominated MW (ICAP)	Percent of Total	Shutdown Cost per Location	Shutdown Cost Per Nominated MW (ICAP)
$0-$1,000	49	0.3%	132.6	1.9%	$7.14	$2.64
$1,000-$1,275	2,323	14.3%	2,931.6	41.2%	$137.74	$109.14
$1,275-$1,550	340	2.1%	293.6	4.1%	$0.31	$0.36
$1,550-$1,849	13,534	83.3%	3,755.3	52.8%	$15.37	$55.40
Total	16,246	100.0%	7,113.2	100.0%	$32.53	$74.29

83 *Id.*
84 161 FERC ¶ 61,153 at P 8 (2017).
85 139 FERC ¶ 61,057 (2012).
86 FERC accepted proposed changes to have the maximum strike price for 30 minute demand response to be $1,000/MWh + 1*Shortage penalty - $1.00, for 60 minute demand response to be $1,000/MWh + (Shortage Penalty/2) and for 120 minute demand response to be $1,100/MWh from ER14-822-000.
87 OATT Attachment K Appendix § 1.10.1A Day-Ahead Energy Market Scheduling (d) (x).
88 "PJM Manual 15: Cost Development Guidelines," § 8.1, Rev. 47 (Oct. 1, 2025).

Table 6-22 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices for the 2025/2026 Delivery Year. The majority of participants, 76.0 percent of locations and 43.8 percent of nominated MW, have a minimum dispatch price between $1,550 and $1,849 per MWh, the maximum price allowed for the 2025/2026 Delivery Year. Almost all registrations, 99.7 percent of locations and 98.0 percent of nominated MW have a dispatch price above $1,000 per MWh. The shutdown cost of resources with $0 to $1,000 per MWh strike prices have the highest average at $175.34 per location, while the shutdown cost of resources with $1,000 to $1,275 per MWh strike prices have the highest average at $87.73 per nominated MW.

Table 6-22 Distribution of registrations and associated MW in the full option across ranges of minimum dispatch: 2025/2026 Delivery Year

Ranges of Strike Prices ($/MWh)	Locations	Percent of Total	Nominated MW (ICAP)	Percent of Total	Shutdown Cost per Location	Shutdown Cost Per Nominated MW (ICAP)
$0-$1,000	59	0.3%	156.1	2.0%	$175.34	$66.25
$1,000-$1,275	4,459	21.5%	3,784.9	47.9%	$74.47	$87.73
$1,275-$1,550	447	2.2%	497.1	6.3%	$0.21	$0.19
$1,550-$1,849	15,738	76.0%	3,460.2	43.8%	$11.15	$50.70
Total	20,703	100.0%	7,898.4	100.0%	$25.02	$65.57

PRD

Price Responsive Demand, or PRD, in the capacity market is capacity based on a firm commitment to reduce load in response to a defined level of real-time energy prices. A PRD offer is a commitment to reduce energy usage by a defined amount in response to real time energy prices during the delivery year. A PRD offer includes MW quantities that the seller will reduce at defined capacity market reservation prices ($/MW-day). PRD offers change the shape of the VRR Curves used in the capacity market auctions.

PRD is provided by a PJM member that represents retail customers that have the ability to reduce load in response to price. In order to be eligible as PRD, the End Use Customer load must be served under a dynamic retail rate or contractual arrangement linked to, or based upon, a PJM real-time LMP trigger at a substation as electrically close as practical to the applicable load.

In order for load to be eligible to be considered as PRD, the end-use customer load must be subject to Supervisory Control as defined in the RAA.[89] End Use Customer loads identified may not sell any other form of demand side management in PJM markets.

PRD must also be curtailed once PJM has declared a Performance Assessment Interval but only if the real-time LMP at the applicable location meets or exceeds the price on the submitted PRD curve at which the load has committed to curtail. The high PRD strike prices mean that PRD could avoid a performance requirement even during a PAI.

In order to commit PRD for a delivery year, a PRD Provider must submit a PRD Plan in advance of the Base Residual Auction which indicates the Nominal PRD Value in MW that the PRD Provider is willing to commit at different reservation prices expressed in ($/MW-day). Additional PRD may participate in the Third Incremental Auction only if the LDA final peak load forecast for the delivery year increases relative to the LDA preliminary peak load forecast used for the Base Residual Auction.

Unlike other capacity resources, once committed, PRD may not be uncommitted or replaced by available capacity resources or Excess Commitment Credits. A PRD Provider may transfer the PRD obligation to another PRD Provider bilaterally. The PRD Provider will receive a Daily PRD Credit ($/MW-day) during the delivery year. A PRD Provider under the FRR Alternative will not be eligible to receive a Daily PRD Credit ($/MW-day) during the delivery year. PRD first cleared the capacity market in the BRA for the 2020/2021 Delivery Year.[90] Table 6-23 shows the Nominated MW of Price Responsive Demand for the 2020/2021 through 2025/2026 Delivery Years.

89 "PJM Manual 18: PJM Capacity Market," § 3A.3, Rev. 62 (December 17, 2025).
90 There were a total of 558 MW of cleared PRD in the 2020/2021 Delivery Year. See PJM Auction Results, <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2020-2021-base-residual-auction-results.ashx?la=en>.

Table 6-23 Nominated MW of price responsive demand: 2020/2021 through 2025/2026 Delivery Years

Delivery Year	RTO	MAAC	EMAAC	SWMAAC	DPL SOUTH	PEPCO	BGE
2020/2021	558.0	558.0	58.0	500.0	27.0	170.0	330.0
2021/2022	510.0	510.0	75.0	435.0	35.7	195.0	240.0
2022/2023	230.0	230.0	40.0	190.0	19.6	110.0	80.0
2023/2024	235.0	235.0	38.0	197.0	15.4	110.0	87.0
2024/2025	305.0	305.0	35.0	270.0	13.0	110.0	160.0
2025/2026	224.0	224.0	14.0	210.0	0.0	75.0	135.0

The cleared PRD is credited the adjusted zonal clearing price of the LDA in which they cleared. The PRD credits are charged to the load of those LDAs by inclusion in the RPM net load price A PRD Provider receives a PRD Credit for each approved Price Responsive Demand registration on a given day. PRD Credits are determined as:[91]

$$
\begin{aligned}
&\textit{PRD Credit}\\
&= [(\textit{Share of Zonal Nominal PRD Value committed in Base Residual Auction}\\
&* (\textit{Zonal Weather}\\
&- \textit{Normalized Peak Load for the summer concluding prior to the commencement of the Delivery Year}\\
&/ \textit{Final Zonal Peak Load Forecast for the Delivery Year})\\
&* \textit{Final Zonal RPM Scaling Factor} * \textit{FPR} * \textit{Final Zonal Capacity Price})\\
&\\
&\textit{plus}\\
&\\
&(\textit{Share of Zonal Nominal PRD Value committed in Third Incremental Auction}\\
&* (\textit{Zonal Weather}\\
&- \textit{Normalized Peak Load for the summer concluding prior to the commencement of the Delivery Year}\\
&/ \textit{Final Zonal Peak Load Forecast for the Delivery Year})\\
&* \textit{Final Zonal RPM Scaling Factor} * \textit{FPR} * \textit{Final Zonal Capacity Price}\\
&* \textit{Third Incremental Auction Component of Final Zonal Capacity Price stated as a Percentage})]
\end{aligned}
$$

Effective with the 2022/2023 Delivery Year, the factor equal to (Zonal Weather-Normalized Peak Load for the summer concluding prior to the commencement of the Delivery Year / Final Zonal Peak Load Forecast for the delivery year) is eliminated in the calculation of the PRD Credit.

Table 6-24 shows the PRD Credits for the 2020/2021 through 2025/2026 Delivery Years.[92]

Table 6-24 PRD Credits for 2020/2021 through 2025/2026 Delivery Years

Delivery Year	PRD Credit
2020/2021	$23,649,865.05
2021/2022	$38,282,769.14
2022/2023	$10,702,158.12
2023/2024	$6,169,725.27
2024/2025	$10,782,581.08
2025/2026	$26,037,205.34

A PRD Provider with a daily commitment compliance shortfall in a subzone/zone for RPM or FRR is assessed a Daily PRD Commitment Compliance Penalty. The Daily PRD Commitment Compliance Penalty is determined as:

$$
\begin{aligned}
&\textit{PRD Commitment Compliance Penalty}\\
&\qquad = \textit{MW shortfall in the Sub} - \textit{zone/ Zone}\\
&\qquad * \textit{Delivery Year Forecast Pool Requirement}\\
&\qquad * \textit{PRD Commitment Compliance Penalty Rate}
\end{aligned}
$$

The revenue collected from assessment of the PRD Commitment Compliance Penalty is distributed to all entities that committed Capacity Resources in the RPM Auctions for the relevant delivery year, based on each entity's prorata share of daily revenues from Capacity Market Clearing Prices in such auctions, net of any daily compliance charges incurred by such entity.

PRD committed in RPM for the current delivery year bids in the PJM Energy Market. PRD Curves may be submitted by PRD Providers in the PJM Energy Market by 1100 at the closing of the day-ahead bid period. PRD Curves submitted by PRD Providers are identified in the day-ahead market software and user interface. PRD bids are modeled in the real-time energy market only, and are modeled in the real-time dispatch algorithms. PRD curves are not modeled in the day-ahead market clearing process. PRD Curves in the energy market are modeled in the real-time dispatch algorithms and can set real-time LMP. PRD Providers with committed PRD are required to have automation of PRD that is needed to respond to real-time LMPs for the PRD Curves that are submitted. The maximum bid price of the PRD Curve is the applicable energy market offer cap plus the shortage penalty, or $1,849 per MWh. When PRD

91 PJM. "Manual 18: Capacity Market," § 9.4.4, Rev. 62 (December 17, 2025).
92 The total credits for PRD were downloaded as of April 13, 2026, and may change as a result of continued PJM billing updates.

sellers offer at the cap, they limit the number of times that PRD is called on to respond. The ability to use the strike price which is above the maximum offer for generation resources and above the energy market price for most intervals permits PRD to economically withhold and renders the PRD resources effectively worthless under almost all circumstances.

On February 7, 2019, PJM filed revisions to its Open Access Transmission Tariff and the Reliability Assurance Agreement to update the rules and requirements for PRD to conform to those for Capacity Performance Resources.[93] PJM's filing sought to change the calculation of the Nominal PRD Value used for determining the PRD Credit from the reduction in load during PJM's annual peak to the lesser of summer and winter load reductions. The proposed changes were intended to ensure that PRD will be available to curtail the same quantity of MW in either the summer or the winter consistent with the requirements of Capacity Performance Resources. In an order issued June 27, 2019, the Commission rejected PJM's proposal finding that it was unjust and unreasonable to calculate the Nominal PRD Value in a manner inconsistent with how an LSE's capacity obligation is determined, and therefore saw no need for consistency between the PRD requirements and the requirements for capacity resources.[94] While treated as an annual product, PRD resources are largely comprised of utility retail programs designed to reduce electric load during periods of high load and/or high wholesale energy prices during the summer season. PRD resources consequently performed poorly when called upon during Winter Storm Elliott for the small number of intervals in which LMP exceeded the strike price.[95]

The PRD rules fall short of defining an effective and efficient product that is aligned with the definition of a capacity resource.[96] PJM's initial filing was rejected by the Commission based on the MMU's comments and PJM's modified filing was accepted.[97] PJM's final filing adopted the MMU's recommendation to exclude the use of Winter Peak Load (WPL) when calculating the nominated MW for PRD resources used to satisfy RPM commitments. Load is allocated capacity obligations based on the annual peak load within PJM. The amount of capacity allocated to load is a function solely of summer coincident peak demand and is unaffected by winter demand. Use of the WPL to calculate the nominated MW for PRD resources to satisfy RPM commitments, would incorrectly restrict PRD to less than the total capacity the customer is required to buy. PJM's adoption of the MMU recommendation correctly values PRD nominated MW. FERC required and PJM's filing also adopted the MMU's recommendation that PRD should be eligible for bonus performance payments during Performance Assessment Intervals (PAI) only when PRD resources respond above their nominated MW value. Allowing PRD resources to collect bonus payments at times when they are not even required to meet their basic obligation would be inconsistent with the basic CP construct as it applies to all other CP resources.[98]

PJM's filing still fell short of completely aligning PRD with the definition of capacity. PRD resources do not have to respond during a PAI if the PRD's trigger price is above LMP during the PAI. All other CP resources have the obligation to perform during a PAI, regardless of the real-time LMP, subject to instructions from PJM. PRD should be held to the same standard during a PAI event. The MMU recommends that PRD be required to respond during a PAI, regardless of whether the real-time LMP at the applicable location meet or exceeds the PRD strike price, to be consistent with all CP resources.

Load Management Events – June through August, 2025

PJM dispatched pre-emergency load management during periods of hot weather on June 23-25, July 28-29 and August 11, 2025.

During the June and July events, long lead time (120 minute) and short lead-time (60 minute) pre-emergency resources were dispatched each day. PJM never declared a level EEA2 emergency, the requirement for deployment of emergency demand response resources, and therefore only dispatched pre-emergency demand resources.[99] PJM did not dispatch quick lead time (30 minute) demand resources. The 60 and 120 minute lead time resources have $1,425 per MWh and $1,100 per MWh maximum strike prices compared to the $1,849 per MWh maximum strike price for 30 minute resources.

93 See "Proposed Amendments to Price Response Demand Rules", Docket No. ER19-1012-000 (Feb. 7, 2019).
94 167 FERC ¶ 61,268
95 See the *2023 Quarterly State of the Market Report for PJM: January through June*, Section 6: Demand Response, Table 6-49.
96 See "Compliance Filing Regarding Price Responsive Demand Rules," Docket No. ER20-271-001 (February 28, 2020).
97 See "Order Rejecting Tariff Revisions," Docket No. ER19-1012-000 (June 27, 2019).
98 October 31 Filing, Attachment B, Proposed Revised OATT § 10A (c).
99 OATT Attachment K, § 8.5.

Load management compliance data for non-PAI event performance is due 45 days after the month in which the event occurs.[100] Data supporting requested energy settlements is due 60 days after an event.[101]

Table 6-25 through Table 6-27 show the deployment and release times, by lead time, for June 23-25, 2025.

Table 6-25 Demand Resource Deployment and Release Times: June 23, 2025

Deploy Time (EPT)	Release Time (EPT)	Resource Type	Lead Time	Zones
1500	2200	Pre-emergency	120 minute	AECO, BGE, DOM, DPL, METED, PECO, PENELEC, PEPCO, PPL, PSEG
1500	2200	Pre-emergency	60 minute	AECO, BGE, DOM, DPL, METED, PECO, PENELEC, PEPCO, PPL, PSEG

Table 6-26 Demand Resource Deployment and Release Times: June 24, 2025

Deploy Time (EPT)	Release Time (EPT)	Resource Type	Lead Time	Zones
1500	2200	Pre-emergency	120 minute	BGE, DOM, PECO, PEPCO
1530	2200	Pre-emergency	120 minute	AECO, DPL, JCPL, METED, PENELEC, PPL, PSEG
1600	2200	Pre-emergency	120 minute	AEP, APS, DAY, DUQ
1630	2200	Pre-emergency	120 minute	ATSI, COMED, DEOK, EKPC
1500	2200	Pre-emergency	60 minute	BEG, DOM, PECO, PEPCO
1530	2200	Pre-emergency	60 minute	AECO, DPL, JCPL, METED, PENELEC, PPL, PSEG
1600	2200	Pre-emergency	60 minute	AEP, APS, DAY, DUQ
1630	2200	Pre-emergency	60 minute	ATSI, COMED, DEOK, EKPC

100 "PJM Manual 18: PJM Capacity Market," § 4.3.1, Rev. 62 (December 17, 2025).
101 "PJM Manual 11: Energy & Ancillary Services Market Operations," § 10.4.1, Rev. 136 (October 1, 2025).

Table 6-27 Demand Resource Deployment and Release Times: June 25, 2025

Deploy Time (EPT)	Release Time (EPT)	Resource Type	Lead Time	Zones
1500	1745	Pre-emergency	120 minute	APS
1500	1810	Pre-emergency	120 minute	AECO, BGE, DPL, JCPL, METED, PECO, PENELEC, PEPCO, PPL, PSEG
1500	1900	Pre-emergency	120 minute	DOM
1500	1745	Pre-emergency	60 minute	APS
1500	1810	Pre-emergency	60 minute	AECO, BGE, DPL, JCPL, METED, PECO, PENELEC, PEPCO, PPL, PSEG
1500	1900	Pre-emergency	60 minute	DOM

Table 6-28 and Table 6-29 show the deployment and release times, by lead time, for July 28-29, 2025.

Table 6-28 Demand Resource Deployment and Release Times: July 28, 2025

Deploy Time (EPT)	Release Time (EPT)	Resource Type	Lead Time	Zones
1645	2100	Pre-emergency	120 minute	BGE, DOM, PEPCO
1545	2100	Pre-emergency	60 minute	BGE, DOM, PEPCO

Table 6-29 Demand Resource Deployment and Release Times: July 29, 2025

Deploy Time (EPT)	Release Time (EPT)	Resource Type	Lead Time	Zones
1500	2045	Pre-emergency	120 minute	ATSI, BGE, DOM, PEPCO
1530	2115	Pre-emergency	120 minute	AEP, EKPC
1600	2130	Pre-emergency	120 minute	AECO, DPL, JCPL, METED, PECO, PENELEC, PPL, PSEG
1800	2145	Pre-emergency	120 minute	APS, COMED, DAY, DEOK, DUQ
1400	2045	Pre-emergency	60 minute	ATSI, BEG, DOM, PEPCO
1430	2115	Pre-emergency	60 minute	AEP, EKPC
1500	2130	Pre-emergency	60 minute	AECO, DPL, JCPL, METED, PECO, PENELEC, PPL, PSEG
1700	2145	Pre-emergency	60 minute	APS, COMED, DAY, DEOK, DUQ

During the August 11 event, long lead time (120 minute), short lead-time (60 minute) and quick lead-time (30 minute) pre-emergency resources were dispatched. PJM also dispatched short lead-time (60) minute and quick lead-time (30) minute emergency demand response resources after declaring a level EEA2 emergency. Table 6-30 shows the deployment and release times, by lead time, for August 11, 2025.

Table 6-30 Demand Resource Deployment and Release Times: August 11, 2025

Deploy Time (EPT)	Release Time (EPT)	Resource Type	Lead Time	Zones
1045	2000	Pre-emergency	120 minute	BGE
1000	2000	Pre-emergency	60 minute	BGE
1000	2000	Pre-emergency	30 minute	BGE
1515	1715	Emergency	60 minute	BGE
1445	1715	Emergency	30 minute	BGE

The emergency procedures employed during June 23-25, July 28-29 and August 11, 2025, did not trigger a PAI. There are no penalties for demand resources failing to perform outside of a PAI. In an order issued July 28, 2023, effective July 30, 2023, FERC approved proposed 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).[102] Under the prior rules, PJM would declare a PAI if pre-emergency or emergency demand response were dispatched. The new rules mean that demand resources may be dispatched both as part of, and absent, a PAI. While demand resources dispatched during a PAI continue to be subject to Non-Performance Assessment charges, demand resources dispatched outside of a PAI are not subject to any event specific penalties.[103] If a demand resource is dispatched only outside of Performance Assessment Events for the delivery year, its performance for the delivery year may be determined based solely on a Load Management Test.[104] Beginning in the 2024/2025 Delivery Year and subsequent delivery years, CSPs may elect to use performance data from a load management event that was not subject to a Non-Performance Assessment (a non-PAI load management event) as performance data for a PJM zonal test event.[105]

Given that calling demand resources no longer triggers a PAI, the MMU recommended in 2023, 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. Load management resources have the same obligation to perform when called upon, regardless of whether the dispatch event occurs as part of a PAI.[106] There is no reason to allow CSPs the optionality of testing in lieu of using non-PAI event performance. If demand resources are only subject to non-PAI dispatch events during the delivery year, their ability to meet their obligations are best defined by their actual operational performance rather than through a scripted test.

Load management resources overall failed to perform to their committed ICAP level during the June 23-25, July 28-29 and August 11, 2025, dispatch events. Load management resources were evaluated based on whether they were successful in reducing their metered load to their nominated Firm Service Level (FSL). Customer Base Line (CBL) is an hourly estimate of the load level of a demand resource in the absence of a demand response event. The expected hourly reduction of each resource is defined as the difference between the CBL and the FSL. The actual hourly reduction is defined as the difference between the CBL and the metered load of the resource adjusted for losses. If a resource reduces to its FSL, then its actual reduction equals its expected reduction. The correct metric is (CBL – metered load)/(CBL – FSL). This metric provides a better assessment of demand response performance than simply comparing metered load to FSL. PJM's metric is (PLC – metered load)/ICAP. During Winter Storm Elliott, demand resource loads were already at a reduced level when dispatched. While deemed to have generally met their ICAP commitments, there was very little incremental reduction provided in order to reach their FSL. The difference between CBL and FSL provides a better estimate of the expected incremental reduction. If a dispatched registration has a CBL equal to or less than the FSL, the expected incremental reduction is zero.

Based on this metric, demand resources provided 69.3 percent of their expected reduction on June 23, 70.6 percent of their expected reduction on June 24 and 68.8 percent of their expected reduction on June 25. Demand resources provided 72.0 percent of their expected reduction on July 28 and 69.6 percent of their expected reduction on July 29. Demand resources provided 49.3 percent of their expected reduction on August 11. Table 6-31 through Table 6-33 summarize these results.

102 See "Order Accepting Tariff Revisions Subject to Condition," Docket No. ER23-1996-000 (July 28, 2023).
103 "PJM Manual 18: PJM Capacity Market," § 8.6, Rev. 62 (December 17, 2025).
104 "PJM Manual 18: PJM Capacity Market," § 8.7, Rev. 62 (December 17, 2025).
105 "PJM Manual 18: PJM Capacity Market," § 8.7, Rev. 62 (December 17, 2025).
106 OATT Attachment K, § 8.5.

Table 6-31 Demand Resource Expected and Actual Performance: June 23-25, 2025

Date	Actual Reduction (MWh)	Expected Reduction (MWh)	Percent Performance
23-Jun-25	6,614	9,540	69.3%
24-Jun-25	15,506	21,963	70.6%
25-Jun-25	3,675	5,339	68.8%
Total	25,796	36,842	70.0%

Table 6-32 Demand Resource Expected and Actual Performance: July 28-29, 2025

Date	Actual Reduction (MWh)	Expected Reduction (MWh)	Percent Performance
28-Jul-25	1,866	2,590	72.0%
29-Jul-25	13,128	18,868	69.6%
Total	14,994	21,458	69.9%

Table 6-33 Demand Resource Expected and Actual Performance: August 11, 2025

Date	Actual Reduction (MWh)	Expected Reduction (MWh)	Percent Performance
11-Aug-25	744	1,510	49.3%
Total	744	1,510	49.3%

Figure 6-2 though Figure 6-4 show the hourly expected and actual reduction values for June 23-25, July 28-29 and August 11, 2025

Figure 6-2 Hourly demand resource expected and actual performance: June 23-25, 2025

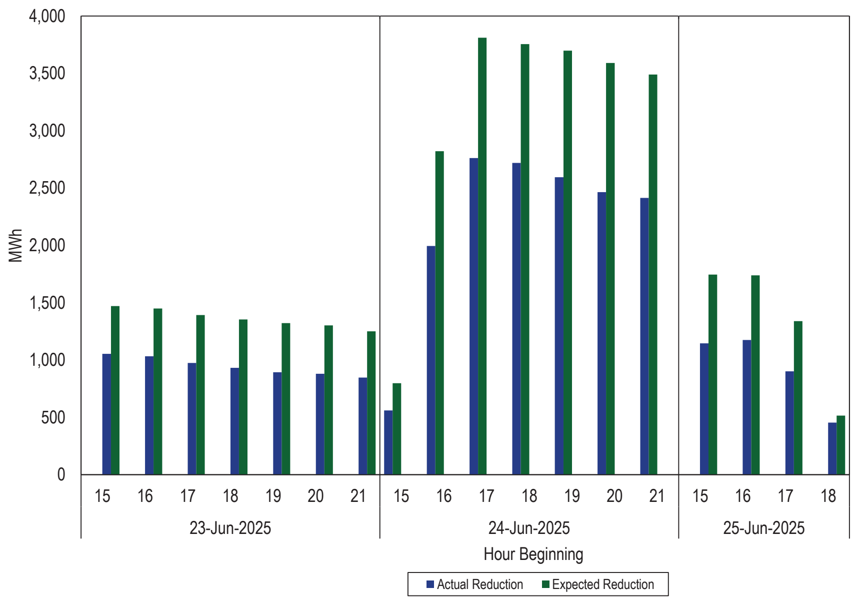


Figure 6-3 Hourly demand resource expected and actual performance: July 28–29, 2025

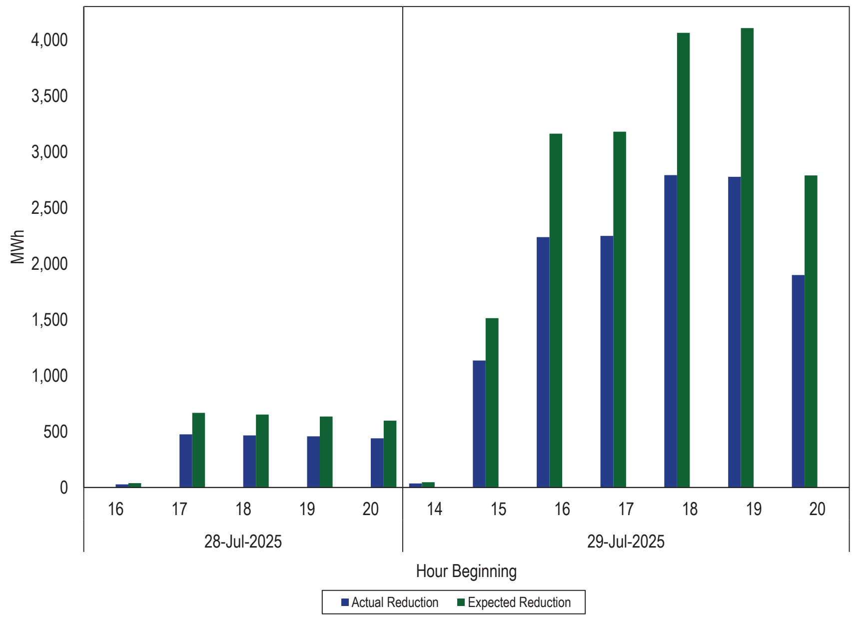
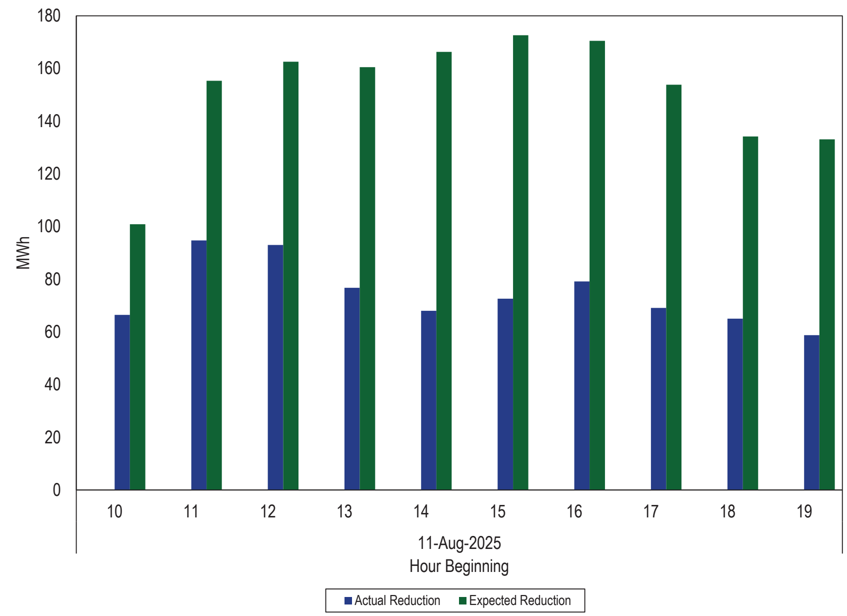


Figure 6-4 Hourly demand resource expected and actual performance: August 11, 2025



The failure of demand resources overall to perform to their committed ICAP level is further evidenced by observing the metered load relative to the Peak Load Contribution (PLC) and FSL. As shown in Figure 6-5 through Figure 6-7, demand resources overall failed to reduce load to their FSL during the June, July and August, 2025 dispatch events.

Figure 6-5 Demand resource metered load compared to PLC and FSL: June 23-25, 2025

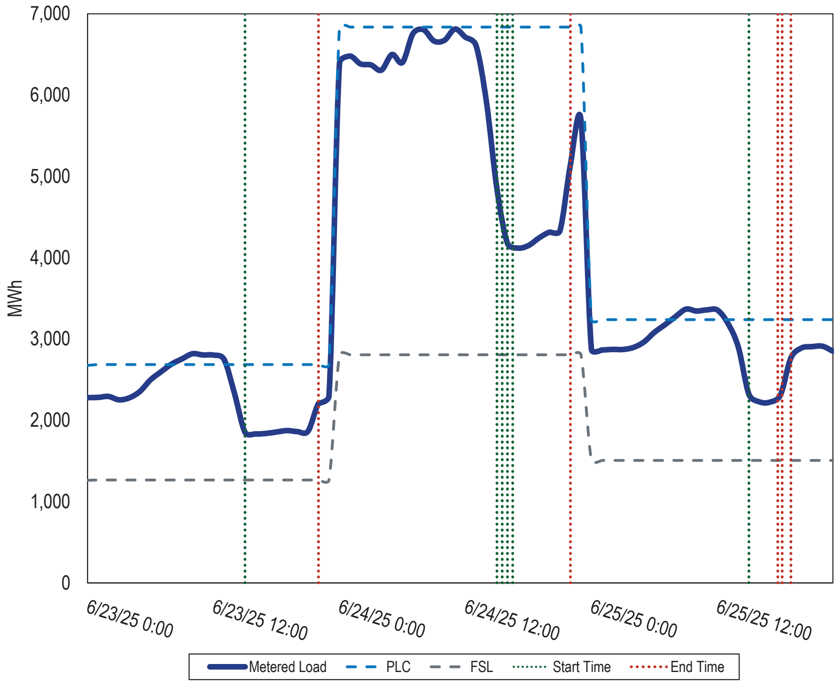


Figure 6-6 Demand resource metered load compared to PLC and FSL: July 28-29, 2025

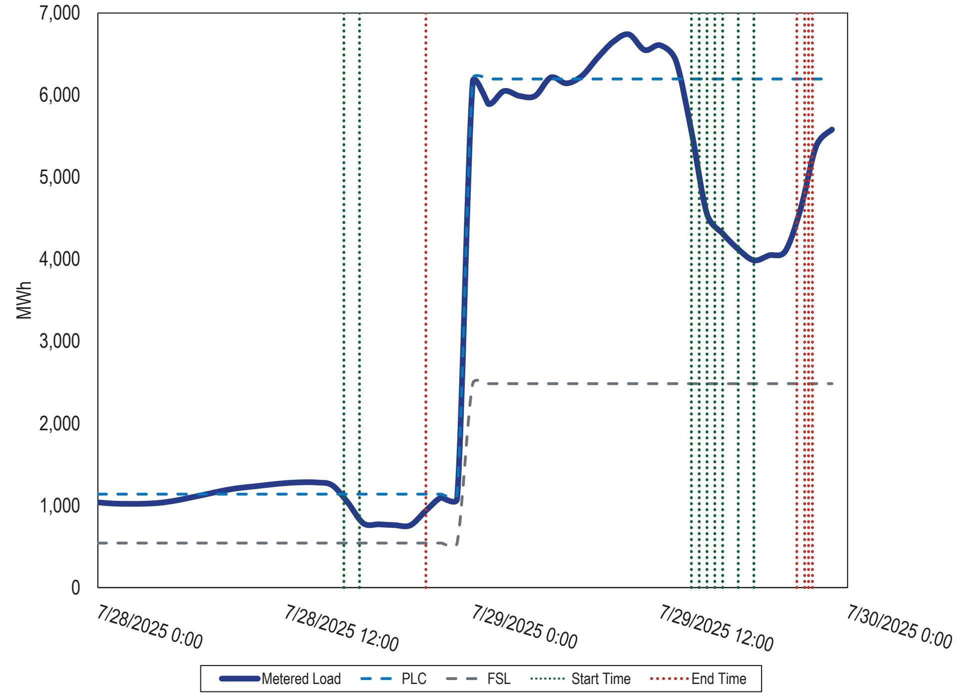
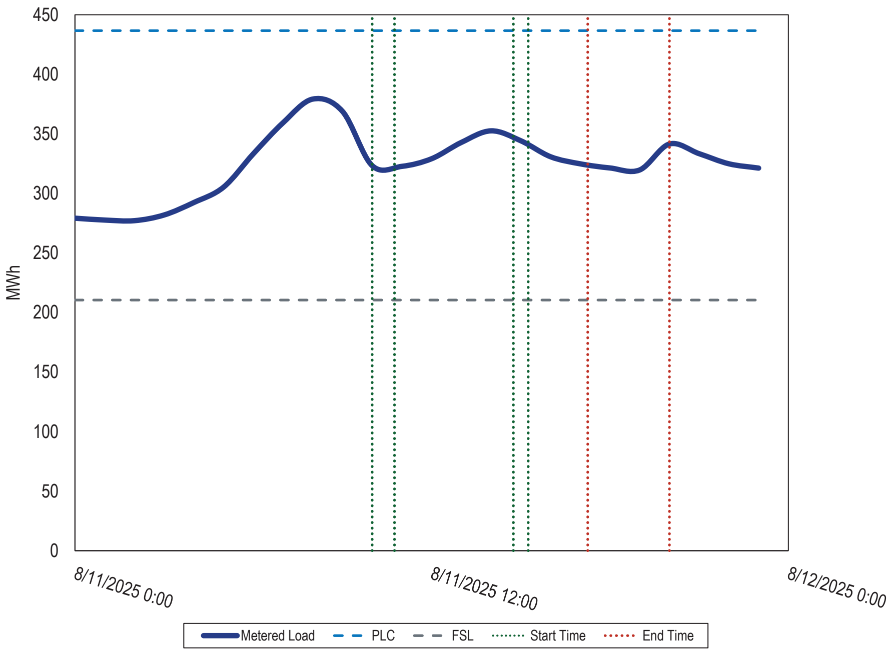


Figure 6-7 Demand resource metered load compared to PLC and FSL: August 11, 2025



Load management demand resources are compensated at real-time LMP for their actual load reduction determined as the difference between the CBL and the metered load. Load management demand resources are paid an emergency load response energy credit equal to their actual load reduction multiplied by the real-time LMP. Load management demand resources are made whole to their offer value which includes their emergency bid price, or strike price and shutdown costs. If the emergency load response energy credit is insufficient to cover the emergency bid based reduction plus shutdown costs, they will receive an emergency load response make whole credit for the difference.

$$\begin{aligned} &\textit{Total Emergency Energy Revenue} \\ &\quad = \textit{Daily Load Response Emergency Credits} \\ &\quad + \textit{Emergency Load Response Make Whole Credit} \end{aligned}$$

where,

$$\begin{aligned} &\textit{Emergency Load Response Make Whole Credit} \\ &\quad = \textit{Emergency Bid cost} + \textit{Emergency Shutdown cost} \\ &\quad - \textit{Daily Load Response Emergency Credits} \end{aligned}$$

Table 6-34 through Table 6-36 show the daily emergency energy payments to load management demand resources for the June, July and August, 2025 dispatch events. For the June 23-25 dispatch event, real-time LMP was sufficient to cover 51 percent of the total emergency energy payments with the remainder compensated through make whole credits. For the July 28-29 dispatch event, real-time LMP was sufficient to cover 18 percent of the total emergency energy payments with the remainder compensated through make whole credits. For the August 11 dispatch event, real-time LMP was sufficient to cover 11 percent of the total emergency energy payments with the remainder compensated through make whole credits. These energy payments are in addition to the capacity market revenues received by load management demand resources. For the 2025/2026 Delivery Year, capacity market revenues paid to load management demand resources average $55.5 million per month.

Table 6-34 Demand resource emergency energy payments: June 23-25, 2025

Date	Real-Time Actual Relief (MWh)	Average Emergency Bid Price ($/MWh)	Average Emergency Shutdown Cost	Average LMP ($/MWh)	Emergency Load Response Energy Credit	Emergency Load Response Energy Make-Whole Credit	Total Emergency Energy Revenue	Average Total Payment ($/MWh)
23-Jun-25	7,397	$1,143	$48	$555	$4,105,528	$3,616,557	$7,722,084	$1,044
24-Jun-25	19,096	$1,134	$82	$662	$12,639,948	$8,862,562	$21,502,510	$1,126
25-Jun-25	5,149	$1,132	$72	$212	$1,092,332	$4,347,255	$5,439,587	$1,056
Total	31,642	$1,136	$67	$564	$17,837,807	$16,826,374	$34,664,181	$1,096

Table 6-35 Demand resource emergency energy payments: July 28-29, 2025

Date	Real-Time Actual Relief (MWh)	Average Emergency Bid Price ($/MWh)	Average Emergency Shutdown Cost	Average LMP ($/MWh)	Emergency Load Response Energy Credit	Emergency Load Response Energy Make-Whole Credit	Total Emergency Energy Revenue	Average Total Payment ($/MWh)
28-Jul-25	2,140	$1,103	$3	$272	$582,748	$1,492,173	$2,074,921	$969
29-Jul-25	18,977	$1,135	$82	$189	$3,583,311	$18,009,167	$21,592,478	$1,138
Total	21,117	$1,119	$42	$197	$4,166,059	$19,501,339	$23,667,399	$1,121

Table 6-36 Demand resource emergency energy payments: August 11, 2025

Date	Real-Time Actual Relief (MWh)	Average Emergency Bid Price ($/MWh)	Average Emergency Shutdown Cost	Average LMP ($/MWh)	Emergency Load Response Energy Credit	Emergency Load Response Energy Make-Whole Credit	Total Emergency Energy Revenue	Average Total Payment ($/MWh)
11-Aug-25	805	$1,739	$6	$185	$148,930	$1,217,333	$1,366,264	$1,696

Load Management Event – Winter Storm Fern

PJM dispatched pre-emergency load management in the BGE, DOM and PEPCO zones during Winter Storm Fern on January 25, 2026. Long lead time (120 minute), short lead-time (60 minute) and quick lead time (30 minute) pre-emergency resources were dispatched. PJM never declared a level EEA2 emergency, the requirement for deployment of emergency demand response resources, and therefore only dispatched pre-emergency demand resources.[107]

Table 6-37 shows the deployment and release times, by lead time, for January 25, 2026.

Table 6-37 Demand Resource Deployment and Release Times: January 25, 2026

Deploy Time (EPT)	Release Time (EPT)	Resource Type	Lead Time	Zones
1430	1900	Pre-emergency	120 minute	BGE, DOM, PEPCO
1530	1900	Pre-emergency	60 minute	BGE, DOM, PEPCO
1500	1900	Pre-emergency	30 minute	BGE, DOM, PEPCO

The emergency procedures employed during January 25, 2026, did not trigger a PAI. There are no penalties for demand resources failing to perform outside of a PAI.

107 OATT Attachment K, Section 8.5.

Load management resources overall failed to perform to their committed ICAP level during the January 25, 2026, dispatch event. Load management resources were evaluated based on whether they were successful in reducing their metered load to their nominated Firm Service Level (FSL). The Customer Base Line (CBL) is an hourly estimate of what the load level of a demand resource would have been in the absence of a demand response event. The expected hourly reduction of each resource is defined as the difference between the CBL and the FSL, to which they are required to reduce. The actual hourly reduction is defined as the difference between the CBL and the metered load of the resource adjusted for losses. The performance metric is the actual reduction divided by the required reduction from actual load to FSL:

$$MMU\ Performance\ Metric = \frac{(CBL - Meter)}{(CBL - FSL)}$$

where

$$Actual\ reduction = CBL - Meter$$
$$Expected\ reduction = CBL - FSL$$

The metric is (CBL – Metered Load) / (CBL – FSL), adjusted for losses. If a resource reduces to its FSL, then its actual reduction equals its expected reduction. This metric provides a better assessment of actual demand response performance than simply comparing metered load to FSL.

In contrast, PJM defines the actual hourly reduction as the difference between the PLC and the metered load. PLC is the defined peak load and not the actual load. PJM defines the actual hourly reduction using the PLC rather than the actual load level (CBL). PJM's metric is (PLC – Metered Load)/(PLC – FSL). PJM's metric does not measure the actual load reduction or the target load reduction correctly. The PJM performance metric is the difference between the peak load and the actual load divided by the difference between the peak load and the level to which the load agreed to reduce:

$$Simplified\ PJM\ Performance\ Metric = \frac{(PLC - Meter)}{(PLC - FSL)}$$

where

$$ICAP = PLC - FSL$$

During Winter Storm Elliott, demand resource loads were already at a reduced level when dispatched. While deemed to have generally met their ICAP commitments, there was very little incremental reduction provided in order to reach their FSL. The difference between CBL and FSL provides a better estimate of the expected and actual incremental reduction. If a dispatched registration has a CBL equal to or less than the FSL, the expected incremental reduction is zero. Based on this metric, demand resources provided 58.1 percent of their expected reduction on January 25, 2026.[108] Table 6-38 summarizes these results.

Table 6-38 Demand Resource Expected and Actual Performance: January 25, 2026

Date	Actual Reduction (MWh)	Expected Reduction (MWh)	Percent Performance
25-Jan-26	1,538	2,649	58.1%
Total	1,538	2,649	58.1%

Figure 6-8 shows the hourly expected and actual reduction values for January 25, 2026.

108 The MMU assumes a CBL equivalent to the metered load for hours when a registration did not request an energy settlement.

Figure 6-8 Hourly demand resource expected and actual performance: January 25, 2026

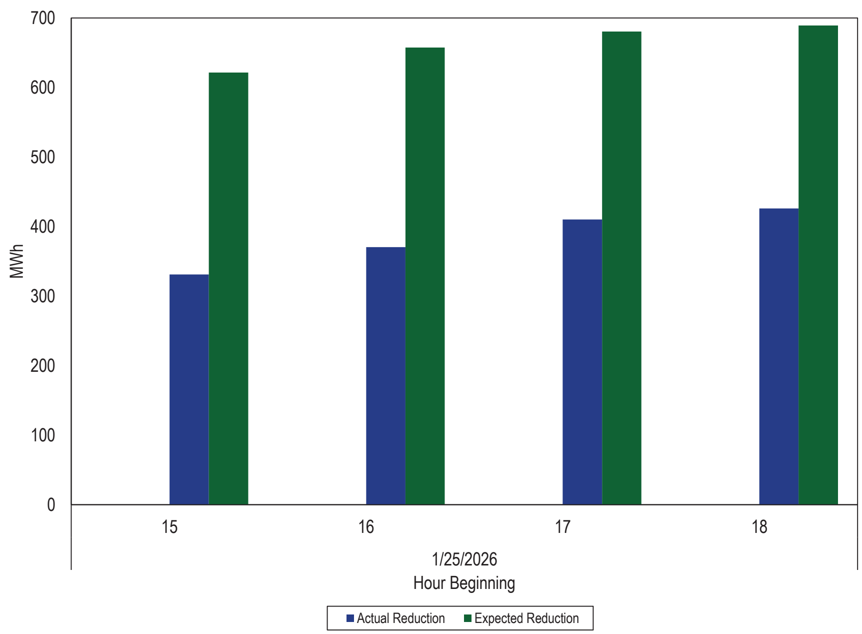
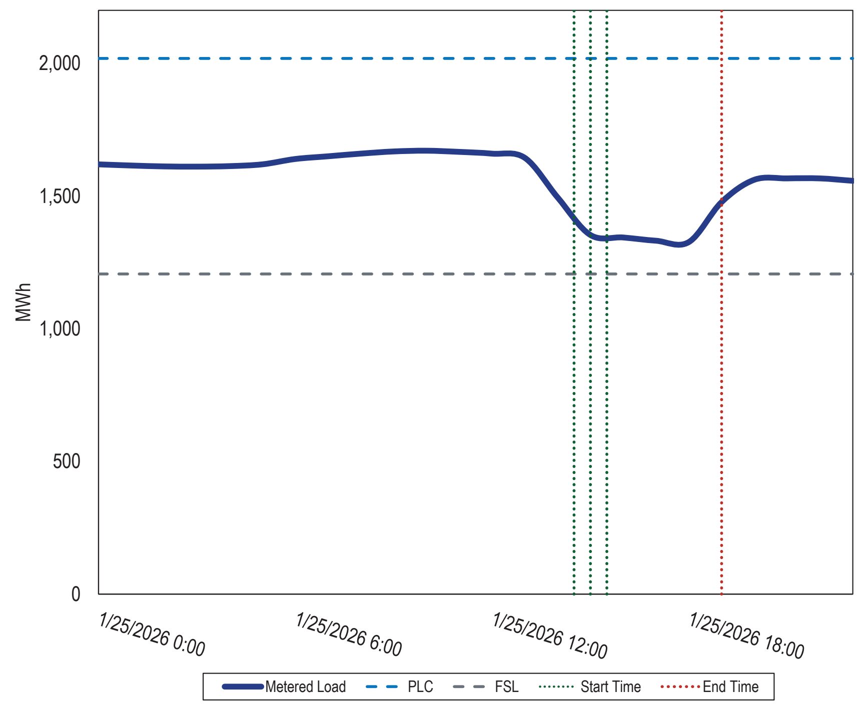


Figure 6-9 Demand resource metered load compared to PLC and FSL: January 25, 2026



The failure of demand resources overall to perform to their committed ICAP level is further evidenced by comparing the metered load relative to the Peak Load Contribution (PLC) and Firm Service Level (FSL). Figure 6-9 shows the aggregate load, FSL, and PLC of the dispatched demand resources on the day of the event. The green and red vertical lines correspond to the deploy and release times indicated in Table 6-37. There are three start times reflecting the fact that PJM called on the resources by lead time, while all resources were released at 19:00. The group's aggregate load was below its PLC before the event began and load was relatively flat in the hours preceding the event. While there was a reduction in load in response to the dispatch signal, demand resources overall failed to reduce load to their FSL during the period they were dispatched. Demand resources are expected to reduce to their FSL when dispatched. failed

Load management demand resources are compensated at real-time LMP for their defined load reduction. Load management demand resources are paid an emergency load response energy credit equal to their defined load reduction multiplied by the real-time LMP. Load management demand resources are also paid the difference between LMP and their strike price plus shutdown costs, the euphemistically titled emergency load response make whole credit:

$$\begin{aligned}&\textit{Total Emergency Energy Revenue}\\&\qquad = \textit{Daily Load Response Emergency Credits}\\&\qquad + \textit{Emergency Load Response Make Whole Credit}\end{aligned}$$

where,

$$\begin{aligned}&\textit{Emergency Load Response Make Whole Credit}\\&\qquad = \textit{Emergency Bid cost} + \textit{Emergency Shutdown cost}\\&\qquad - \textit{Daily Load Response Emergency Credits}\end{aligned}$$

Table 6-39 shows the daily emergency energy payments to load management demand resources for January 25, 2026.[109] Real-time LMP was sufficient to cover 68 percent of the total emergency energy payments with the remainder compensated through make whole credits. These energy payments are in addition to the capacity market revenues received by load management demand resources. For the 2025/2026 Delivery Year, capacity market revenues paid to load management demand resources average $55.5 million per month.

Table 6-39 Demand resource emergency energy payments: January 25, 2026

Date	Real-Time Actual Relief (MWh)	Average Emergency Bid Price ($/MWh)	Average Emergency Shutdown Cost	Average LMP ($/MWh)	Emergency Load Response Energy Credit	Emergency Load Response Energy Make-Whole Credit	Total Emergency Energy Revenue	Average Total Payment ($/MWh)
25-Jan-26	1,794	$1,644	$15	$725	$1,301,011	$609,075	$1,910,086	$1,065

PJM stated that the demand side performance issues in the summer of 2025 required modifications to the nonperformance penalties applicable to demand side resources.[110] PJM's proposed solution was to institute Tariff and RAA changes to assess nonperformance penalties to demand resources when they are dispatched during non-Performance Assessment Interval (non-PAI) events at a rate equal to 50 percent of the existing Performance Assessment Interval (PAI) penalty rate.[111]

PJM's proposed penalty rate of 50 percent of the PAI penalty rate is ineffective at incenting performance. Demand resources that completely fail to perform are profitable under PJM's penalty. This non-PAI penalty structure also makes little sense when considering the aim of penalizing poor performing resources. PJM's proposed non-PAI penalty structure for demand response resources imposes significantly higher penalties for failing a test event than for failing to perform during an actual emergency dispatch. It is irrational to assign greater financial consequences to a test failure in a simulated environment than to a failure during a real reliability event.

PJM's approach allocates the penalty charges collected during non-PAI events as bonus payments to defined overperforming demand resources. If penalty charges from underperforming demand resources are greater than the bonus payments to overperformers, the residual amount would be allocated to load on a pro-rata basis. The MMU recommends paying the penalty payments to the customers who paid for the demand resources and therefore bore the cost of the nonperformance.

109 Actual relief (MWh) and revenues reflect performance beginning at the time the demand response registration is dispatched, adjusted for its applicable lead time, and continuing through the conclusion of the event.
110 See PJM. MIC. *Approved Minutes from the Market Implementation Committee,* (December 3, 2025) <https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2025/20251203/20251203-minutes.pdf> .
111 See PJM. MIC. *Options & Packages Matrix – Load Management & Price Responsive Demand Event Performance,* (March 11, 2026) <https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2026/20260311/20260311-item-02-4---options--packages-matrix---load-management--price-responsive-demand-event-performance.xls>.

PJM's performance metric and penalty approach are both incorrect and together do not function as an effective incentive for demand resources to perform.

PJM's performance metric relies on the peak load contribution (PLC) as the counterfactual value to represent what demand would have been in absence of the event. The PLC is a static value that is not based on conditions specific to or load trends prior to the event. This can lead to an incorrectly estimated counterfactual, registrations may be compensated for demand reductions that did not occur, and is in direct conflict with the tariff's requirement that dispatched registrations reduce their demand.[112] [113] For example, a resource that actually increases its demand during an event would be assessed as a positive performer as long as their demand stays below the PLC. The MMU recommends using the customer baseline (CBL) in place of the PLC. PJM already relies on the CBL for economic settlements. The CBL is intended to be an estimate of counterfactual demand, what demand would have been but for the reduction. The PLC is not an estimate of counterfactual demand. The CBL takes into account the impact of time, demand prior to the event, and other relevant external conditions.

PJM's performance metric zeroes out negative performance. PJM considers a registration that increases its demand during an event to have a zero percent performance, regardless of the impact. Registrations with a negative performance should be penalized for increasing their demand in response for a PJM dispatch call to reduce demand. An actual increase in demand is worse than a simple failure to reduce, during the tight system conditions that lead to the dispatch of pre-emergency and emergency load management resources. It is impossible to assess the performance of the group if registrations whose increases in demand would have cancelled out the positive performance of other registrations are not fully accounted for.

PJM allows curtailment service providers (CSPs) to net the performance of their registrations across the entire PJM footprint. Netting masks poor performers and local impacts, which can vary by location.

112 See PJM OATT, Attachment K, Section 8.5.
113 See PJM, Intra-PJM Tariffs, RAA, Definition of "Firm Service Level".

Together, PJM's proposal combines a flawed penalty structure with the incorrectly defined performance metric to create a paradigm in which PJM customers both pay for a demand reduction service that is not delivered and are denied compensation for that failure when penalty revenues are paid to demand resources rather than load.

Economic Demand Response

The Economic Demand Response Program is for demand response customers that offer into the day-ahead or real-time energy market.[114] The estimated load reduction is paid the zonal LMP, as long as the zonal LMP is greater than the monthly Net Benefits Test threshold.

Market Structure

Table 6-40 shows the average hourly HHI for each month and the average hourly HHI for January 1, 2025, through February 28, 2026.[115] The ownership of economic demand response resources was highly concentrated in the first two months of 2025 and 2026.[116] Table 6-40 lists the share of reported reductions provided by, and the share of credits claimed by the four largest CSPs in each year. The HHI for economic demand response was highly concentrated in the first two months of 2026. The HHI for economic demand response in the first two months of 2026 increased by 371, 4.5 percent, from 8199 in the first two months of 2025 to 8570 in the first two months of 2026.

114 Also known in the PJM Market Rules as the Economic Load Response Program.
115 Load response credits and reductions were downloaded as of April 13, 2026, and may change as a result of continued PJM billing updates.
116 All HHI calculations in this section are at the parent company level.

Table 6-40 Average hourly MWh HHI and market concentration in the economic program: January 2025 through February 2026[117]

	Average Hourly MWh HHI			Top Four CSPs Share of Reduction			Top Four CSPs Share of Credit		
Month	2025	2026	Percent Change	2025	2026	Change in Percent	2025	2026	Change in Percent
Jan	8382	8776	4.7%		100.0%			0.0%	
Feb	8017	8364	4.3%		100.0%			0.0%	
Mar	8510								
Apr	8547								
May	8944								
Jun	9383								
Jul	9142								
Aug	9198								
Sep	9195								
Oct	9400								
Nov	8121								
Dec	7745			100.0%			0.0%		
Total	8969	8664	(3.4%)	100.0%	100.0%		100.0%	0.0%	

Market Performance

Table 6-41 shows the total MW reported reductions made by participants in the economic program and the total credits paid for these reported reductions in January through March, 2010 through 2026.[118] The average credits per MWh paid increased by $202.66 per MWh, 310.3 percent, from $65.32 per MWh in the first three months of 2025 to $267.99 per MWh in the first three months of 2026. Curtailed energy for the economic program was 60,808 MWh in the first three months of 2026, a decrease of 96,652 MWh, 61.4 percent, as compared to curtailed energy for the economic program in the first three months of 2025. Total credits paid for the economic load response program in the first three months of 2026 were $16,295,677, an increase of $6,010,020, 58.4 percent, compared to the total credits paid for the economic load response program in the first three months of 2025.

117 Omitted reduction and credit share values are based on confidentiality rules that require published data to include more than four owners.

118 Load response credits were downloaded as of April 13, 2026, and may change as a result of continued PJM billing updates.

Table 6-41 Credits paid to economic program participants: January through March, 2010 through 2026

(Jan-Mar)	Total MWh	Total Credits	$/MWh
2010	8,139	$321,648	$39.52
2011	3,272	$240,304	$73.45
2012	1,030	$30,406	$29.52
2013	21,048	$1,083,755	$51.49
2014	58,195	$12,727,388	$218.70
2015	38,644	$4,175,116	$108.04
2016	16,038	$672,506	$41.93
2017	12,973	$534,378	$41.19
2018	14,623	$951,955	$65.10
2019	7,183	$390,708	$54.39
2020	1,213	$34,124	$28.14
2021	3,974	$228,086	$57.39
2022	6,294	$401,846	$63.84
2023	7,705	$383,318	$49.75
2024	28,552	$2,764,797	$96.83
2025	157,459	$10,285,657	$65.32
2026	60,808	$16,295,677	$267.99

Economic demand response resources that are dispatched by PJM in both the economic and emergency programs are paid the higher price defined in the emergency rules.[119] For example, assume a demand resource has an economic offer price of $100 per MWh and an emergency strike price of $1,800 per MWh. If this resource were scheduled to reduce in the day-ahead energy market, the demand resource would receive $100 per MWh, but if an emergency event were called during the economic dispatch, the demand resource would receive its emergency strike price of $1,800 per MWh instead. The rationale for this rule is not clear.[120] All other resources that clear in the day-ahead market are financially firm at the clearing price. Payment at a guaranteed strike price and the ability to set energy market prices at the strike price effectively grant the seller the right to exercise market power.

Figure 6-10 shows monthly economic demand response credits and MWh, from 2010 through March 31, 2026.

119 "PJM. Manual 11: Energy & Ancillary Services Market Operations," § 10.4.5, Rev. 136 (October 1, 2025).

120 *Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 831, 157 FERC ¶ 61,115 (2016) ("Order No. 831").

Figure 6-10 Economic program credits and MWh by month: 2010 through March 2026

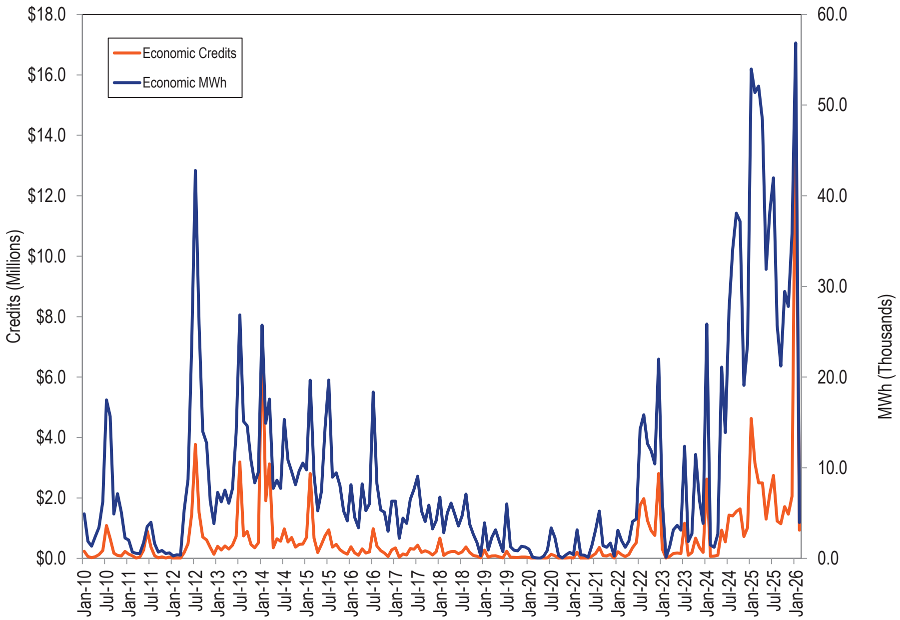


Table 6-42 shows performance for the first three months of 2025 and 2026 in the economic program by control zone. Total reported reductions under the economic program decreased by 96,652 MWh, 61.4 percent, from 157,459 MWh in the first three months of 2025 to 60,808 MWh in the first three months of 2026. Total revenue under the economic program increased by $16.3 million, 58.4 percent, from $210.3 million in the first three months of 2025 to $16.3 million in the first three months of 2026.[121]

Emergency and economic demand response energy payments are uplift and not compensated by LMP revenues. Economic demand response energy costs are assigned to real-time exports from the PJM Region 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 the price determined under the net benefits test for that month.[122] The zonal allocation is shown in Table 6-42.

121 Economic demand response reductions that are submitted to PJM for payment but have not received payment are not included in Table 6-39. Payments for Economic demand response reductions are settled monthly.
122 "PJM Manual 28: Operating Agreement Accounting," § 11.2.2, Rev. 104 (March 1, 2026).

Table 6-42 Economic program participation by zone: January through March, 2025 and 2026

	Credits			MWh Reductions			Credits per MWh Reduction		
Zone	2025 (Jan-Mar)	2026 (Jan-Mar)	Percent Change	2025 (Jan-Mar)	2026 (Jan-Mar)	Percent Change	2025 (Jan-Mar)	2026 (Jan-Mar)	Percent Change
ACEC	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
AEP	$3,608,236.68	$4,726,348.51	31.0%	60,626	26,702	(56.0%)	$59.52	$177.00	197.4%
APS	$352,057.45	$9,208,997.51	2,515.8%	8,282	19,464	135.0%	$42.51	$473.12	1,012.9%
ATSI	$2,591,211.44	$1,940,794.63	(25.1%)	17,516	11,336	(35.3%)	$147.93	$171.20	15.7%
BGE	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
COMED	$17,386.96	($5.63)	(100.0%)	492	(0)	(100.0%)	$35.34	$74.60	111.1%
DAY	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
DUKE	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
DUQ	$3,649,880.07	$291,438.35	(92.0%)	69,914	2,347	(96.6%)	$52.21	$124.18	137.9%
DOM	$35,109.84	$72,929.46	107.7%	141	143	1.9%	$249.88	$509.25	103.8%
DPL	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
JCPLC	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
MEC	$0.00	$265.01	NA	0	3	NA	NA	$82.08	NA
OVEC	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
PECO	$6,971.27	$5,822.29	(16.5%)	116	61	(47.5%)	$59.97	$95.43	59.1%
PE	$0.00	$22,840.92	NA	0	472	NA	NA	$48.35	NA
PEPCO	$804.22	$113.02	(85.9%)	12	2	(81.8%)	$66.22	$51.07	(22.9%)
PPL	$5,577.30	$0.00	NA	22	0	NA	$255.78	NA	NA
PSEG	$18,421.64	$26,132.90	41.9%	340	276	(18.8%)	$54.19	$94.66	74.7%
REC	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
Total	$10,285,656.87	$16,295,676.98	58.4%	157,459	60,808	(61.4%)	$65.32	$267.99	310.3%

Table 6-43 shows average reported MWh reductions and credits by hour for the first three months of 2025 and 2026. The average LMP during Load Response is the reduction weighted average hourly DA or RT load weighted LMP during the economic load response hour. In the first three months of 2025, 55.2 percent of the reported reductions and 54.2 percent of credits occurred in hours ending 0900 EPT to 2100 EPT, and in the first three months of 2026, 53.4 percent of the reported reductions and 51.8 percent of credits occurred in hours ending 0900 EPT to 2100 EPT. The average LMP during load response increased by $168.64 per MWh, 285.8 percent, from $59.01 per MWh in the first three months of 2025 to $227.65 per MWh in the first three months of 2026.

Table 6-43 Hourly frequency distribution of economic program reported MWh reductions and credits: January through March, 2025 and 2026

	MWh Reductions			Program Credits			Average LMP during Load Response		
Hour Ending (EPT)	2025 (Jan-Mar)	2026 (Jan-Mar)	Percent Change	2025 (Jan-Mar)	2026 (Jan-Mar)	Percent Change	2025 (Jan-Mar)	2026 (Jan-Mar)	Percent Change
1 through 6	31,550	14,500	(54%)	$1,898,760	$3,872,652	104%	$54.30	$230.80	325%
7	9,025	2,952	(67%)	$678,945	$881,699	30%	$75.14	$258.37	244%
8	9,639	3,114	(68%)	$825,639	$986,162	19%	$85.16	$267.03	214%
9	8,253	2,299	(72%)	$551,600	$695,167	26%	$60.35	$237.99	294%
10	6,572	2,052	(69%)	$391,706	$552,423	41%	$53.33	$200.19	275%
11	6,316	2,520	(60%)	$398,980	$645,550	62%	$57.53	$210.30	266%
12	5,862	2,480	(58%)	$348,687	$626,392	80%	$51.02	$200.57	293%
13	5,414	2,436	(55%)	$318,201	$553,834	74%	$48.37	$182.92	278%
14	5,012	2,284	(54%)	$285,022	$548,275	92%	$46.56	$184.01	295%
15	4,623	2,330	(50%)	$257,664	$536,503	108%	$46.14	$180.98	292%
16	4,653	2,289	(51%)	$264,654	$536,667	103%	$47.89	$188.11	293%
17	5,424	2,455	(55%)	$321,461	$560,641	74%	$50.60	$192.02	279%
18	7,817	3,112	(60%)	$526,196	$798,727	52%	$62.35	$205.06	229%
19	9,028	2,862	(68%)	$639,210	$840,256	31%	$69.15	$227.84	229%
20	9,340	2,755	(71%)	$677,151	$814,606	20%	$68.73	$239.68	249%
21	8,537	2,573	(70%)	$595,566	$736,577	24%	$66.70	$225.26	238%
22	7,423	2,693	(64%)	$485,035	$785,674	62%	$62.02	$235.88	280%
23 through 24	12,973	5,102	(61%)	$821,181	$1,323,874	61%	$56.85	$430.71	658%
Total	157,459	60,808	(61%)	$10,285,657	$16,295,677	58%	$59.01	$227.65	291%

Table 6-44 shows the distribution of economic program reported MWh reductions and credits by ranges of real-time zonal load-weighted average LMP in the first three months of 2025 and 2026. In the first three months of 2026, 58.7 percent of reported MWh reductions and 88.5 percent of program credits occurred during hours when the applicable zonal LMP was higher than $175 per MWh.

Table 6-44 Frequency distribution of economic program zonal load-weighted average LMP (By hours): January through March, 2025 and 2026

	MWh Reductions			Program Credits		
LMP	2025 (Jan-Mar)	2026 (Jan-Mar)	Percent Change	2025 (Jan-Mar)	2026 (Jan-Mar)	Percent Change
$0 to $25	137	0	(100%)	$1,662	$0	(100%)
$25 to $50	81,705	10,869	(87%)	$3,190,983	$430,632	(87%)
$50 to $75	38,882	4,772	(88%)	$2,330,560	$281,000	(88%)
$75 to $100	14,255	1,415	(90%)	$1,233,599	$117,139	(91%)
$100 to $125	8,419	2,393	(72%)	$933,273	$215,743	(77%)
$125 to $150	5,147	3,081	(40%)	$689,715	$382,138	(45%)
$150 to $175	2,478	2,579	4%	$385,410	$444,900	15%
> $175	6,436	35,700	455%	$1,520,454	$14,424,125	849%
Total	157,459	60,808	(61%)	$10,285,657	$16,295,677	58%

Economic Load Response revenues are paid by real-time loads and real-time scheduled exports as an uplift charge. Table 6-45 shows the sum of real-time and day-ahead Economic Load Response charges paid in each zone and paid by exports. In the first two months of 2026, DOM Zone has paid the highest Economic Load Response charges.

Table 6-45 Zonal Economic Load Response charge: January through February, 2026[123]

Zone	January	February	Total
AECO	$162,556	$10,665	$173,220
AEP	$2,585,812	$155,185	$2,740,997
APS	$995,151	$61,417	$1,056,567
ATSI	$1,115,158	$65,516	$1,180,673
BGE	$628,421	$39,637	$668,058
COMED	$720,439	$46,347	$766,786
DAY	$325,668	$17,843	$343,511
DUKE	$497,419	$26,800	$524,219
DUQ	$212,694	$13,060	$225,753
DOM	$2,608,523	$166,074	$2,774,597
DPL	$403,794	$26,954	$430,749
EKPC	$347,971	$18,927	$366,898
JCPLC	$380,391	$24,010	$404,401
MEC	$283,975	$17,552	$301,528
OVEC	$2,119	$126	$2,246
PECO	$721,920	$46,399	$768,319
PE	$304,221	$18,038	$322,259
PEPCO	$575,259	$36,181	$611,440
PPL	$806,254	$50,809	$857,063
PSEG	$724,818	$45,089	$769,906
REC	$22,173	$1,340	$23,513
Exports	$937,914	$45,060	$982,973
Total	$15,362,649	$933,028	$16,295,677

Table 6-46 shows the total zonal Economic Load Response charge per GWh of real-time load and exports in the first two months of 2026.[124]

123 Load response charges were downloaded as of April 13, 2026, and may change as a result of continued PJM billing updates.
124 Load response charges were downloaded as of April 13, 2026, and may change as a result of continued PJM billing updates.

Table 6-46 Zonal economic load response charge per GWh of load and exports: January through February, 2026

Zone	January	February	Zonal Average
AECO	$0.190	$0.014	$0.102
AEP	$0.187	$0.013	$0.100
APS	$0.195	$0.014	$0.105
ATSI	$0.179	$0.012	$0.096
BGE	$0.204	$0.015	$0.109
COMED	$0.084	$0.007	$0.045
DAY	$0.192	$0.012	$0.102
DUKE	$0.198	$0.013	$0.105
DUQ	$0.179	$0.013	$0.096
DOM	$0.199	$0.014	$0.107
DPL	$0.207	$0.015	$0.111
EKPC	$0.213	$0.014	$0.114
JCPLC	$0.189	$0.013	$0.101
MEC	$0.189	$0.013	$0.101
OVEC	$0.175	$0.012	$0.093
PECO	$0.192	$0.014	$0.103
PE	$0.189	$0.013	$0.101
PEPCO	$0.207	$0.015	$0.111
PPL	$0.193	$0.014	$0.103
PSEG	$0.188	$0.013	$0.101
REC	$0.185	$0.012	$0.099
Exports	$0.182	$0.012	$0.097
Monthly Average	$0.187	$0.013	$0.100

Table 6-47 shows the monthly day-ahead and real-time Economic Load Response charges for the first three months of 2025 and 2026. The day-ahead Economic Load Response charges increased by $6.1 million, 60.5 percent, from $10.1 million in the first three months of 2025 to $16.3 million in the first three months of 2026. The real-time Economic Load Response charges decreased $0.12 million, 85.8 percent, from $0.1 million in the first three months of 2025 to $002 million in the first three months of 2026.[125]

125 Load response charges were downloaded as of April 13, 2026, and may change as a result of continued PJM billing updates. Economic demand response reductions that are submitted to PJM for payment but have not received payment are not included. Payments for Economic demand response reductions are settled monthly.

Table 6-47 Monthly day-ahead and real-time economic load response charge: January 2025 through March 2026

	Day-ahead Economic Load Response Charge			Real-time Economic Load Response Charge		
Month	2025	2026	Percent Change	2025	2026	Percent Change
Jan	$4,606,507.89	$15,342,285.32	233.1%	$24,927.49	$20,363.59	(18.3%)
Feb	$3,044,896.16	$932,924.94	(69.4%)	$106,924.73	$103.14	(99.9%)
Mar	$2,490,134.89	$0	(100.0%)	$12,265.71	$0	(100.0%)
Apr	$2,490,770.17					
May	$1,292,723.75					
Jun	$2,126,584.47					
Jul	$2,742,529.18					
Aug	$1,233,541.61					
Sep	$1,145,640.38					
Oct	$1,708,020.71					
Nov	$1,459,914.52					
Dec	$2,054,581.53					
Total (Jan-Mar)	$10,141,538.94	$16,275,210.26	60.5%	$144,117.93	$20,466.73	(85.8%)

Table 6-48 shows registered sites and MW for the last day of each month for the period January 1, 2022, through March 31, 2026. Registration is a prerequisite for CSPs to participate in the economic program. Average monthly registrations decreased by 2, 0.5 percent, from 575 in the first three months of 2025 to 573 in the first three months of 2026. Average monthly registered MW increased by 61 MW, 2.0 percent, from 3,053 MW in the first three months of 2025 to 3,114 MW in the first three months of 2026.

Most economic demand response resources are registered in the emergency demand response program. Resources registered in both programs do not need to register for the same amount of MW. There are 193 economic registrations and 199 capacity registrations in the emergency program that share the same location IDs in both programs. There are 1,718.9 nominated economic MW, 55.2 percent of all economic MW and 1,506.3 nominated capacity MW, 18.8 percent of all nominated capacity MW in the emergency program that share the same location IDs in both programs.

Table 6-48 Economic program registrations on the last day of the month: 2022 through March 2026[126]

	2022		2023		2024		2025		2026	
Month	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW
Jan	323	2,233	347	2,874	462	3,176	563	2,981	576	3,103
Feb	323	2,256	354	2,870	472	3,299	576	3,013	575	3,165
Mar	330	2,377	361	2,930	476	3,244	587	3,166	567	3,074
Apr	330	2,382	373	2,932	481	3,207	580	3,157		
May	326	2,377	378	3,006	487	3,230	585	3,275		
Jun	315	2,323	396	2,929	501	2,942	581	3,147		
Jul	310	2,412	412	3,096	524	3,266	581	3,139		
Aug	318	2,451	428	3,163	528	3,027	576	3,157		
Sep	329	2,565	440	3,335	531	3,017	582	3,246		
Oct	333	2,575	453	3,362	543	2,922	597	3,260		
Nov	338	2,593	478	3,499	560	2,948	586	3,223		
Dec	359	2,640	487	3,493	570	2,989	576	3,095		
Avg	328	2,432	409	3,124	511	3,106	581	3,155	573	3,114

The registered MW in the economic load response program are not a good measure of the MW available for dispatch in the energy market. Economic resources can dispatch up to the amount of MW registered in the program, but are not required to offer any MW. Table 6-49 shows the sum of maximum economic MW dispatched by registration each month from January 1, 2014, through February 28, 2026. The monthly maximum is the sum of each registration's monthly noncoincident maximum dispatched MW and annual maximum is the sum of each registration's annual noncoincident maximum dispatched MW. The monthly maximum dispatched MW decreased 3.6 MW, 0.9 percent, in the first two months of 2026 compared to the first two months of 2025.[127]

Table 6-49 Sum of maximum MW reported reductions for all registrations per month: 2014 through February 2026

	Sum of Peak MW Reductions for all Registrations per Month												
Month	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Jan	446	169	139	123	142	88	28	21	34	50	281	404	445
Feb	307	336	128	83	70	58	11	86	34	18	102	409	361
Mar	369	198	120	111	71	38	12	20	30	53	102	271	
Apr	146	143	118	54	71	41	3	22	43	70	84	245	
May	151	161	131	169	70	22	12	9	53	141	247	152	
Jun	483	833	121	240	105	26	38	125	110	96	213	342	
Jul	665	1,362	1,316	936	518	770	135	134	150	309	469	370	
Aug	358	272	249	141	581	33	99	827	162	191	376	198	
Sep	795	816	263	140	112	76	31	35	88	392	223	281	
Oct	214	136	150	88	69	29	9	31	67	80	344	337	
Nov	166	127	116	81	54	35	12	31	58	88	138	289	
Dec	155	122	147	83	11	31	14	19	116	77	315	270	
Annual	1,739	1,858	1,451	1,217	758	830	196	921	263	735	616	705	456

126 Data for years 2010 through 2017 are available in the *2017 Annual State of the Market Report for PJM.*
127 Maximum MW reductions were downloaded as of April 13, 2026, and may change as a result of continued PJM billing updates.

Table 6-50 shows total settlements submitted for 2014 the first three months of 2014 through 2026. A settlement is counted for every day on which a registration is dispatched in the economic program.

Table 6-50 Settlements submitted in the economic program: January through March, 2014 through 2026

(Jan-Mar)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Number of Settlements	1,314	602	267	347	361	172	83	123	369	100	269	902	1,197

Table 6-51 shows the number of CSPs, and the number of participants in their portfolios, submitting settlements for 2014 through 2026. The number of active participants increased by 10, 32.3 percent, from 31 in the first three months of 2025 to 41 in the first three months of 2026. All participants must be registered through a CSP.

Table 6-51 Participants and CSPs submitting settlements in the economic program by year: January through March, 2014 through 2026

(Jan-Mar)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Active CSPs	12	11	6	6	11	9	7	8	5	5	4	4	4
Active Participants	115	47	17	19	26	18	9	18	15	9	19	31	41

Issues

FERC Order No. 831 requires that each RTO/ISO market monitoring unit verify all energy offers above $1,000 per MWh.[128] Economic resources offer into the energy market and must provide supporting documentation to offer above $1,000 per MWh. FERC stated, "[t]he offer cap reforms, however, do not apply to capacity-only demand response resources that do not submit incremental energy offers into energy markets."[129] Demand resources participate in both the capacity and energy markets and are not capacity only resources. It is not clear whether FERC intended to exclude demand resources with high strike prices from the requirements of FERC Order No. 831. Demand resources should not be permitted to make offers above $1,000 per MWh without the same verification requirements applied to economic resources or generation resources. The MMU recommends that the rules for maximum offer for the emergency and pre-emergency program match the maximum offer for generation resources.

On April 1, 2012, FERC Order No. 745 was implemented in the PJM economic program, requiring payment of full LMP for dispatched demand resources when a net benefits test (NBT) price threshold is exceeded. This approach replaced the payment of LMP minus the charges for wholesale power and transmission included in customers' tariff rates. Following FERC Order No. 745, all ISO/RTOs are required to calculate an NBT threshold price each month above which the net benefits of DR are deemed to exceed the cost to load.

PJM calculates the NBT price threshold by first retrieving generation offers from the same month of the prior calendar year for which the calculation is being performed. PJM then adjusts a portion of each prior year offer, representing the typical share of fuel costs in energy offers in the PJM Region, for changes in fuel prices based on the ratio of the reference month spot fuel price to the study month forward fuel price. To accomplish this adjustment, the ratio of forward prices for the study month to the spot fuel prices for the reference month is used as a scaling factor. If the forward price for the study month was $7.08 and the spot fuel

128 157 FERC ¶ 61,115 at P 139 (2016).
129 *Id.* at 8.

price from the reference month was $6.75, then the ratio is 1.05. The offers of generation units are then adjusted by this scaling factor. The price of fuel typically represents 80 to 90 percent of a generator's offer with the remainder being variable operations and maintenance costs. Where generators offer multiple points on a curve, each point on the curve is adjusted in this manner. The offers are then combined to create daily supply curves for each day in the period. The daily curves are then averaged to form an average supply curve for the study month. PJM then uses a non-linear least squares estimation technique to determine an equation that approximates and smooths this average supply curve. The NBT threshold price is the price at the point where the price elasticity of supply is equal to 1.0 for this estimated supply curve equation.[130] PJM publishes the details of the equation and parameters each month along with the NBT results.

The NBT test is a crude tool that is not based in market logic. The NBT threshold price is a monthly estimate calculated from a monthly supply curve that does not incorporate real-time or day-ahead prices. In addition, it is a single threshold price used to trigger payments to economic demand response resources throughout the entire RTO, regardless of their location and regardless of locational prices.

The necessity for the NBT 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 nor does it require a payment from PJM markets.

When the zonal LMP is above the NBT threshold price, economic demand response resources that reduce their power consumption are paid the full zonal LMP. When the zonal LMP is below the NBT threshold price, economic demand response resources are not paid for any load reductions.[131]

130 "PJM Manual 11: Energy & Ancillary Services Market Operations," §10.3.1, Rev. 136 (October 1, 2025)
131 "PJM Manual 11: Energy & Ancillary Services Market Operations," §10.3.4, Rev. 136 (October 1, 2025)

Table 6-52 shows the NBT threshold price for the historical test from August 2010 through July 2011, and April 2012, when FERC Order No. 745 was implemented in PJM, through March 2026. The historical test was used as justification for the method of calculating the NBT for future months. From 2012 through 2021, the NBT threshold price exceeded the lowest historical test result of $34.07 per MWh one time, in March 2014 when the NBT threshold price was $34.93. The NBT threshold price exceeded the lowest historical test result of $34.07 per MWh in 10 of 12 months of 2022. In the first three months of 2026, the NBT threshold price did not exceed the lowest historical test result of $34.07 per MWh.

Table 6-52 Net benefits test threshold prices: August 2010 through April 2026

	Historical Test ($/MWh)		Net Benefits Test Threshold Price ($/MWh)														
Month	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Jan	$42.03	$42.03		$25.72	$29.51	$29.63	$23.67	$32.60	$26.27	$29.44	$20.04	$18.11	$26.93	$40.25	$20.53	$24.35	$31.65
Feb	$41.48	$40.49		$26.27		$26.52	$26.71	$31.57	$24.65	$23.49	$19.29	$18.70	$34.59	$29.79	$22.28	$25.94	$26.71
Mar	$38.36	$38.48	$28.43	$24.73	$34.93	$24.99	$22.10	$30.56	$25.50	$22.15	$17.44	$20.82	$30.00	$23.75	$18.70	$25.63	$25.00
Apr	$38.07	$36.76	$27.92	$27.94	$32.59	$24.92	$19.93	$30.45	$25.56	$22.36	$15.91	$23.47	$35.14	$23.68	$17.17	$30.31	
May	$35.82	$34.68	$23.46	$27.73	$32.08	$23.71	$20.69	$29.65	$25.52	$21.01	$14.69	$21.40	$42.94	$23.43	$16.82	$27.76	
Jun	$36.12	$35.09	$23.86	$28.44	$31.62	$23.80	$20.62	$27.14	$23.59	$20.20	$15.56	$22.35	$44.29	$22.33	$18.41	$22.48	
Jul	$37.68	$27.92	$22.99	$29.42	$31.62	$23.03	$20.73	$24.42	$23.57	$19.76	$14.66	$21.59	$48.67	$22.66	$21.15	$25.54	
Aug	$35.57	$33.86	$24.47	$28.58	$29.85	$23.17	$23.24	$22.75	$23.53	$19.57	$14.58	$20.52	$44.08	$24.89	$17.48	$25.38	
Sep	$34.07	$31.07	$24.33	$28.80	$29.83	$21.69	$24.70	$21.51	$22.23	$18.19	$15.16	$23.06	$55.39	$25.04	$14.71	$20.92	
Oct	$38.10		$25.96	$29.13	$30.20	$21.48	$26.50	$21.70	$23.84	$20.20	$17.25	$24.24	$55.97	$21.73	$14.22	$22.20	
Nov	$36.83		$25.63	$31.63	$29.17	$22.28	$29.27	$26.41	$23.89	$21.11	$18.35	$29.20	$49.57	$23.12	$19.81	$28.34	
Dec	$37.04		$25.97	$28.82	$29.01	$22.31	$29.71	$29.16	$26.35	$22.24	$19.47	$32.85	$42.75	$24.43	$20.13	$31.56	
Average	$37.60	$35.60	$25.30	$28.10	$30.95	$23.96	$23.99	$27.33	$24.54	$21.64	$16.87	$23.03	$42.53	$25.42	$18.45	$25.87	$27.79

Table 6-53 shows the number of hours that at least one zone in PJM had day-ahead LMP or real-time LMP higher than the NBT threshold price.[132] In the first three months of 2026, the highest zonal LMP in PJM was higher than the NBT threshold price 2,071 hours out of 2,159 hours, or 95.9 percent of all hours. Reductions occurred in 784 hours, 37.9 percent, of those 2,071 hours in the first three months of 2026. The last three columns illustrate how often economic demand response activity occurred when LMPs exceeded NBT threshold prices for January 1, 2024, through March 31, 2026. There are no economic payments when demand response occurs and zonal LMP is below the NBT threshold. Demand response reported reductions occurred in none of the hours in which LMP was below the NBT threshold price in the first three months of 2025, and none of the hours in which LMP was below the NBT threshold price in the first three months of 2026.

Table 6-53 Hours with price higher than NBT and economic load response occurrences in those hours: January 2025 through March 2026

	Number of Hours		Number of Hours with LMP Higher than NBT			Percent of NBT Hours with Economic Load Response		
Month	2025	2026	2025	2026	Percent Change	2025	2026	Percentage Change
Jan	744	744	737	668	(9.4%)	97.4%	85.6%	(11.8%)
Feb	672	672	672	661	(1.6%)	95.5%	32.1%	(63.5%)
Mar	743	743	742	742	0.0%	97.7%		
Apr	720		662			94.7%		
May	744		580			82.4%		
Jun	720		685			77.2%		
Jul	744		718			91.8%		
Aug	744		603			78.4%		
Sep	720		708			74.6%		
Oct	744		744			99.1%		
Nov	721		721			96.9%		
Dec	744		735			88.0%		
Total	8,760	2,159	8,307	2,071	(75.1%)	89.8%	37.9%	(52.0%)

132 The MWh for demand resources were downloaded as of April 13, 2026, and may change as a result of continued PJM billing updates.

Energy Efficiency

Energy Efficiency Resources (EE) are not capacity resources and do not contribute to reliability. FERC ruled on November 5, 2024, that EE should no longer be paid the capacity market clearing price effective with the 2026/2027 Delivery Year.[133] See the 2025 Annual State of the Market Report for PJM for detailed information on the EE program and its impacts.

Peak Shaving Adjustment

Peak Shaving Adjustment (PSA) provides an alternative means for demand response to participate in the Reliability Pricing Model (RPM). Rather than being on the supply side of the capacity market, a PSA participates on the demand side through a modified peak load forecast for the zone in which the Peak Shaving Adjustment resources are located. The peak shaving adjusted load forecast is included in the VRR curve. An important issue is that the resultant reduction in capacity obligation is socialized across all loads in the zone rather than directly benefitting the resources providing the Peak Shaving Adjustment.[134] This eliminates the incentive for individual customers to participate in peak shaving. The solution is a retail rate design that directly assigns the benefits of peak shaving to individual customers. The retail rate design is within the authority of state regulators and not the authority of FERC which has jurisdiction over the wholesale markets.

A PSA plan must include: the basis for the planned reductions; a THI trigger for interruption; the duration of the interruption in hours; the MW value of the curtailment; the months of the offer; all historical addbacks for the nominated programs.[135] Any resource selling a PSA must reduce load on any day in which its trigger is met or exceeded. The trigger is based on the actual maximum daily temperature humidity index (THI) for the relevant PJM zone. When the trigger is met, the PSA must comply with its defined offer parameters including number of hours of interruption. Failure to operate to these parameters will lead to a reduction in the peak shaving adjustment value in future delivery years. Performance is measured based on the aggregated Customer Baseline (CBL). PJM applies a three year rolling average of the annual peak shaving performance ratings to the program's total participating MW in order to determine its peak shaving adjustment.

Distributed Energy Resources

Distributed Energy Resources (DER) include generation connected to distribution level facilities, behind the meter generation, and energy storage facilities connected to the distribution grid or to load. FERC issued Order No. 2222 on September 17, 2020, with the goal of removing barriers for small distributed resources to enter the wholesale market by allowing them to aggregate in order to encourage competition, but larger resources, up to 5 MW, can participate.[136] On May 1, 2025, FERC issued an order accepting all of the final elements of PJM's compliance filing including delaying the effective date for the DER Aggregation Participation Model to February 2, 2028. PJM is currently developing implementation details for DER Aggregation Resources (DERAs) at the Distributed Resources Subcommittee (DISRS).

PJM proposed Manual 18 updates for Planned DER Capacity Resource's participation in the 2028/2029 BRA.[137] The changes include detailed business rules for DER Capacity Aggregation Resources, DER plan requirements, RPM commitment compliance, and test failure charges. All DER will be planned resources for the 2028/2029 auction, meaning PJM will not require the CSP to register an actual physical resource prior to the auction. The MMU identified a loophole in the market power mitigation rules applicable to planned DER in PJM's proposed Manual 18 language. The loophole exists because a DER aggregation can change resource types between the time of clearing in an auction and the actual delivery year. For example, a DER aggregation can offer as a homogeneous demand resource and then change to a heterogeneous DER resource in the actual delivery year. This would allow a DER aggregation to avoid market power mitigation rules in the capacity market. Under the proposed rules, if a planned DER Capacity Aggregation Resource consists of only demand response resources (homogeneous DR), it is exempt from the market power mitigation rules. Planned resources can change types between BRAs and IAs, or between capacity auctions and delivery years. The rules

133 See 189 FERC ¶ 61,095, *reh'g denied*, 190 FERC ¶ 62,005 (2025).
134 See "Peak Shaving Adjustment Proposal," Docket No. ER19-511-000 (December 7, 2018).
135 "PJM Manual 19: Load Forecasting and Analysis," Attachment D, Rev. 37 (Dec. 18, 2024).
136 See 172 FERC ¶ 61,247 at PP 6–7.
137 See "Manual 18 Revisions - Redline," from the October 9, 2025, meeting of the MIC <https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2025/20251009/20251009-item-01-1---manual-18-revisions---redline.pdf>.

allow a planned DER Capacity Aggregation Resource solely comprised of demand response resources that was not subject to market power mitigation rules in a capacity auction to add generation after the auction. This would allow the added generation to avoid market power mitigation rules. This loophole should be closed with a simple rule change to prevent the behavior.

The MMU recommends that DER aggregations that clear in a capacity auction not be permitted to change status from homogeneous demand response to any other status for any additional auctions for the same delivery year, or for the delivery year.

Getting the rules right at the beginning of DER development is essential to the active and effective participation of DER in the wholesale power markets in a manner that enhances rather than undermines the efficiency and competitiveness of the power markets. In addition, getting the implementation details right is critical in keeping the original intention of Order No. 2222 to enhance competition in wholesale markets while removing barriers for small distributed resources. To date, PJM is not meeting these objectives.

Nodal Aggregation and Size

The PJM market is a nodal market. Nodal markets provide efficient price signals to resources in an economically dispatched, security constrained market. Aggregation behind a single node is feasible, is consistent with the nodal market principle, and will encourage competition. The accepted DER Aggregation Participation Model allows multinodal aggregation for small resources that satisfy a few conditions. Energy injection from DERs across multiple nodes, even if it is small, will change congestion patterns that PJM would not have the ability to predict and control. Allowing DER aggregation across nodes even for small resources is not necessary and would distort the nodal market signals that indicate where capacity and energy are needed and their impacts on congestion. The MMU recommends that PJM use a nodal approach for DER participation in PJM markets that excludes multinodal aggregation.

The accepted DER Aggregation Participation Model does not propose a maximum size requirement for DER Aggregation Resources. This loophole would allow larger DERs to divide one larger resource into multiple DERs less than 5 MW and register them as one DER Aggregation Resource, undermining the intent of the DER approach. To avoid this loophole, there should be a maximum size requirement on DER Aggregation Resources. The MMU recommends that PJM include a 5.0 MW maximum size cap on DER aggregations.

EDC Role

The EDCs' dual role as the distribution system operator and as a DER Aggregator is a threat to PJM's competitive market. When an EDC, acting in its proposed role as a market participant, controls its competitors' access to the market, the result is not structurally competitive. The result would be to create barriers to competition, exactly the opposite of FERC's intent. EDCs have a very significant role to play as designers, builders and managers of the local grids, without competing with DER providers. The accepted DER Aggregation Participation Model does not prevent EDCs from serving as DER aggregators or address the market power issues, based on a reference to the provision of Order No. 2222 that prohibits RTOs/ISOs from limiting the business models under which DER aggregators can operate. FERC, however, stated that it could revisit the EDCs' role in the PJM markets, if "evidence of undue discrimination regarding the participation of DER aggregations in RTO/ISO markets" is discovered.[138] The MMU continues to recommend that EDCs not be allowed to participate in markets as DER aggregators in addition to their EDC role.

Cases where EDCs override PJM dispatch instructions should be communicated to PJM and recorded in the PJM market systems for operations and market monitoring purposes. When DER Aggregation Resources update bidding parameters due to override instructions from the EDC, the MMU should be able to check whether the update is due to an override or other operational or economic reasons. When the EDC itself is the DER Aggregator and it overrides its PJM dispatch instruction, it should also be communicated to PJM and recorded. FERC clarified that if an EDC's override actions are discriminatory or involve the exercise of market power such behavior would

138 182 FERC ¶ 61,143 at P 334.

violate the terms of PJM's tariff and that such actions can be monitored and addressed through existing mechanisms such as Attachment M.[139] However, the proposed tariff language does not explicitly define the MMU's role in monitoring or mitigating the potential exercise of market power by EDCs. To enable efficient and effective market monitoring, EDCs and DERAs should be explicitly required to provide information requested by the MMU. The MMU recommends that the Commission require PJM to include in OATT Attachment M a statement explicitly affirming 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 DER Aggregation Resources.

Net Metering Resources

A net metering resource is a single electric customer location that has both generation and load, where the generation can exceed the load, and the customer pays for energy or receives compensation for energy based on the net energy output measured at the customer meter. Retail customers on a net metering tariff with their distribution utility pay the retail rate when consuming and are paid the retail rate when selling energy. These resources cannot participate in the energy or capacity markets, because they already receive full compensation for their output. That retail rate compensation includes credits for ancillary services charges.

According to PJM, no net metering resources in the PJM footprint provide ancillary services as part of a retail program.[140] From PJM's perspective, this means all net metering resources in its territory are eligible to participate in its ancillary services market.[141] PJM argues that even if a resource is compensated for the same service at the retail and the wholesale level, it should not be considered double counting. Under this proposal, a net metered resource that receives credits through its retail rate for reducing its ancillary services purchase can also receive payment from PJM for providing the same ancillary services. That is clearly double counting. The accepted DER Aggregation Participation Model allows EDCs to raise concerns about double counting but neither PJM nor an EDC may preclude a Component DER from providing ancillary services based on the resources being compensated for ancillary services at the retail level. No resource should be paid more than once for its services. If the net energy metering resources receive credits at a rate that includes compensation for ancillary services, that means they are providing the service and being compensated for it. The MMU recommends that net metering resources be prohibited from participating in wholesale ancillary services markets if they are compensated for the service at the retail level.

On December 19, 2025, PJM submitted a tariff revision filing at FERC proposing to create a new participation model called Economic Load Response Regulation Only Participants.[142] PJM proposes to permit economic demand response to sell regulation by injecting power onto the grid without the rules that govern such injections. The PJM tariff prohibits demand side resources from injecting power in any PJM market. PJM proposes a new and inappropriate and unsupported form of participation for demand resources. A new form of market participation must be supported with a logical argument, not simply by creating special and unduly discriminatory exceptions to existing rules. PJM would create a new category of economic demand response that violates the current demand response rules and the current rules about injecting power onto the grid. This is a fundamental change to the PJM market demand response model, which was specifically designed for resources that do not inject power onto the grid. The proposal creates discriminatory preferences for a small group of potential participants, who are on retail Net Energy Metering ("NEM") tariffs and want to participate in the regulation market, and undercuts PJM demand response rules without justification or evidence. The December 19th Filing is not simply an acceleration of the implementation of the Order No. 2222 rules for Distributed Energy Resources ("DERs"), but creates a permanent exception to those rules without any detailed support or analysis. Under the December 19th Filing, Economic Load Response Regulation Only Participants would operate under a new set of rules that do not include the protections established and approved in PJM's Order No. 2222 compliance proceedings. Those protective rules include a maximum size requirement, a standard of review in the registration process, and nodal modelling. The MMU opposed the proposal during the stakeholder processes and submitted

139 See 188 FERC ¶ 61,076 at P169.
140 See Order No. 2222 Compliance Filing of PJM Interconnection, L.L.C., Docket No. ER22-962 (February 1, 2022) at 41.
141 FERC Docket No. ER22-962-005 at 15.
142 PJM Interconnection, L.L.C., Economic Load Response Regulation Only Participants, Docket No. ER26-846-000, (December 19, 2025).

comments in the docket.[143] [144] FERC issued a deficiency letter to PJM on February 13, 2026.[145] FERC approved the proposal on May 5, 2026.[146]

143 Monitoring Analytics, L.L.C., Comments of the Independent Market Monitor for PJM Interconnection, L.L.C., Docket No. ER26-846 (January 9, 2026).
144 Monitoring Analytics, L.L.C., Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, ER26-846 (February 11, 2026).
145 FERC Deficiency Letter, Docket No. ER26-846 (February 13, 2026).
146 195 FERC ¶ 61,090 (May 5, 2026).

7 Net Revenue

The Market Monitoring Unit (MMU) analyzed measures of PJM energy market structure, participant conduct and market performance. As part of the review of market performance, the analysis includes the theoretical new entrant net revenues for combustion turbine (CT), combined cycle (CC), coal plant (CP), diesel (DS), nuclear, solar, and wind generating units.

Overview

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 2026 compared to the first three months of 2025. The net effects were that in the first three months of 2026, average energy market theoretical net revenues increased by 213 percent for a new combustion turbine (CT), increased by 144 percent for a new combined cycle (CC), increased by 199 percent for a new coal plant (CP), increased by 64 percent for a new nuclear plant, increased by 1,326 percent for a new diesel (DS), increased by 29 percent for a new onshore wind installation, increased by 65 percent for a new offshore wind installation and increased by 10 percent for a new solar installation.
- The price of natural gas and coal increased in the first three months of 2026. The marginal costs of a new CT and CC were greater than the marginal costs of a new CP in January and February, and lower in March 2026.
- In the first three months of 2026, spark spreads in BGE and Western Hub increased and spark spreads in COMED and PSEG decreased compared to the first three months of 2025. In the first three months of 2026, dark and quark spreads increased in BGE, COMED, PSEG and Western Hub compared to the first three months of 2025.
- Of the 16 PJM nuclear plants analyzed, all are expected to cover their avoidable costs from energy and capacity market revenues in 2026, 2027 and 2028, without any subsidies.

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.)

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 recent change to the definition of the VRR curve in the capacity market weakens the connection between the energy and capacity markets by discounting the net revenue offset, overstating net CONE and creating an arbitrary floor price and, as a result, undermines an important part of the fundamental PJM market design.[1]

PJM's introduction of a flawed form of ELCC for defining available unforced capacity has made the definition of reliability less clear. The ELCC derate factors are 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 that result, among other things, in the undervaluing of gas fired generation capacity.

Net Revenue

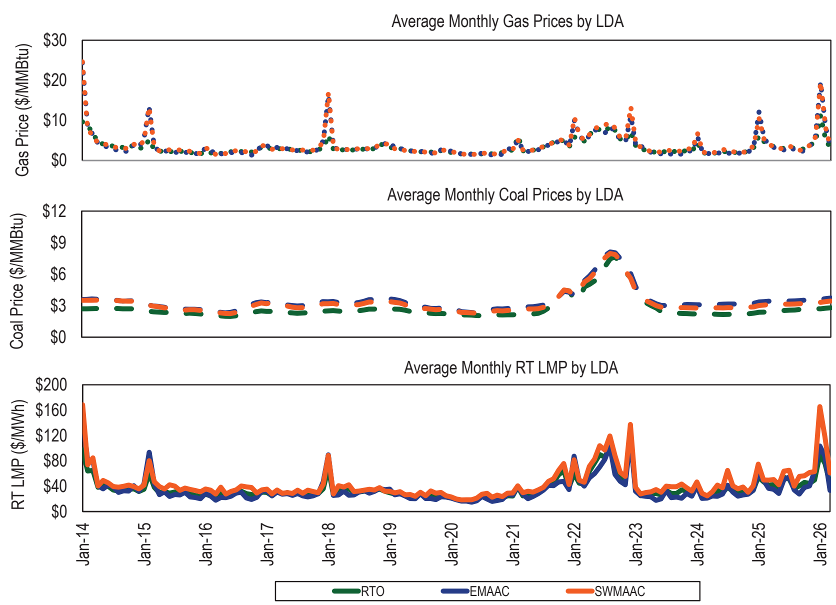
When compared to annualized fixed costs and avoidable costs, net revenue is an indicator of generation investment profitability, and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation and to maintain existing generation in PJM markets. Net revenue equals total revenue received by generators from PJM energy, capacity and ancillary service markets including uplift payments, and from the provision of black start, and from subsidies like RECs, less the short run marginal costs of energy production. In other words, net revenue is the amount that remains, after the short run marginal costs of energy production have been subtracted from gross revenue. Net revenue is the contribution to fixed costs, which include a return on investment, depreciation and income taxes, and to avoidable costs, which include long term and intermediate term operation and maintenance expenses.[2] Net revenue is the contribution to total fixed and avoidable costs received by generators from all PJM markets.

In a perfectly competitive, energy only market in long run equilibrium, net revenue from the energy market would be expected to equal the annualized fixed and avoidable costs for the marginal unit, including a competitive return on investment. The PJM market design includes other markets that contribute to the payment of fixed and avoidable costs. In PJM, the energy, capacity and ancillary service markets are all significant sources of revenue to cover the fixed and avoidable costs of generators, as are payments for the provision of black start and reactive services. Thus, in a perfectly competitive market in long run equilibrium, with energy, capacity and ancillary service markets, net revenue from all sources would be expected to equal the annualized fixed and avoidable costs of generation for the marginal unit. Net revenue is a measure of whether generators are receiving competitive returns on invested capital and of whether market prices are high enough to encourage entry of new capacity and to encourage maintaining existing capacity. In actual wholesale power markets, where equilibrium seldom occurs, net revenue is expected to fluctuate above and below the equilibrium level based on actual conditions in all relevant markets. The current definition of net revenue is not fully accurate as the FERC ordered definition uses price-based offers at times and does not include revenue from opportunity cost adders for environmentally constrained resources.

Net revenues are significantly affected by energy prices, fuel prices and capacity prices. The real-time load-weighted average LMP in the first three months of 2026 increased $35.24 per MWh, or 67.5 percent, from the first three months of 2025, from $52.20 per MWh to $87.44 per MWh. Gas prices and coal prices increased in the first three months of 2026 compared to the first three months of 2025. The price of eastern natural gas was 43.3 percent higher, the price of western natural gas was 27.5 percent higher; the price of Northern Appalachian coal was 15.4 percent higher; the price of Central Appalachian coal was 7.8 percent higher; and the price of Powder River Basin coal was 6.0 percent higher (Figure 7-1). The price of ULSD NY Harbor Barge (ultra low sulfur diesel) was 22.3 percent higher in the first three months of 2026 than in the first three months of 2025.

1 See Protest of the Independent Market Monitor for PJM, Docket No. ER26-455-000 (December 8, 2025); 194 FERC ¶ 61,049 (2026).
2 Avoidable costs are sometimes referred to as going forward costs.

Figure 7-1 Energy market net revenue factor trends: 2014 through March 2026



Spark, Dark, and Quark Spreads

The spark, dark, and quark spreads are defined as the difference between the LMP received for selling power and the cost of fuel used to generate power, converted to a cost per MWh. The spark spread compares power prices to the cost of gas, the dark spread compares power prices to the cost of coal, and the quark spread compares power prices to the cost of uranium. The spread is a measure of the approximate difference between revenues and marginal costs and is an indicator of net revenue and profitability.

$$Spread\left(\frac{\$}{MWh}\right) = LMP\left(\frac{\$}{MWh}\right) - Fuel\ Price\left(\frac{\$}{MMBtu}\right) * Heat\ Rate\left(\frac{MMBtu}{MWh}\right)$$

Spread volatility is a result of fluctuations in LMP and the price of fuel. Spreads can be positive or negative.

In the first three months of 2026, spark spreads in BGE and Western Hub increased and spark spreads in COMED and PSEG decreased compared to the first three months of 2025. In the first three months of 2026, dark and quark spreads increased in BGE, COMED, PSEG and Western Hub compared to the first three months of 2025. In the first three months of 2026, the volatility of spark, dark and quark spreads increased in BGE, COMED, PSEG and Western Hub compared to the first three months of 2025.[3]

Table 7-1 shows average peak hour spreads by year and Table 7-2 shows the associated standard deviations.

Table 7-1 Peak hour spark, dark, and quark spreads ($/MWh)

	BGE			COMED			PSEG			Western Hub		
Jan-Mar	Spark	Dark	Quark	Spark	Dark	Quark	Spark	Dark	Quark	Spark	Dark	Quark
2025	$23.06	$34.02	$46.93	$10.90	$18.95	$20.93	($6.60)	$20.68	$37.32	$14.68	$27.83	$40.74
2026	$36.69	$66.81	$81.62	$3.76	$19.54	$21.43	$0.58	$39.65	$56.97	$21.97	$52.42	$67.24
Percent change	59%	96%	74%	(66%)	3%	2%	(109%)	92%	53%	50%	88%	65%

Table 7-2 Peak hour spark, dark, and quark spread standard deviation ($/MWh)

	BGE			COMED			PSEG			Western Hub		
Jan-Mar	Spark	Dark	Quark	Spark	Dark	Quark	Spark	Dark	Quark	Spark	Dark	Quark
2025	$54.9	$64.9	$64.6	$28.7	$32.1	$31.8	$97.8	$38.7	$38.1	$56.4	$45.6	$45.2
2026	$125.8	$152.7	$152.6	$95.7	$62.8	$62.7	$114.0	$98.5	$98.3	$125.1	$117.1	$117.0
Percent change	129%	135%	136%	233%	95%	97%	17%	154%	158%	122%	157%	159%

Figure 7-2 and Figure 7-3 show the hourly spark and dark spread for peak hours for BGE, COMED, PSEG, and Western Hub.

3 Spark spreads use a combined cycle heat rate of 7,000 Btu/kWh. Dark and quark spreads use a heat rate of 10,000 Btu/kWh

Figure 7-2 Hourly spark spread (gas) for peak hours ($/MWh): 2021 through March 2026[4]

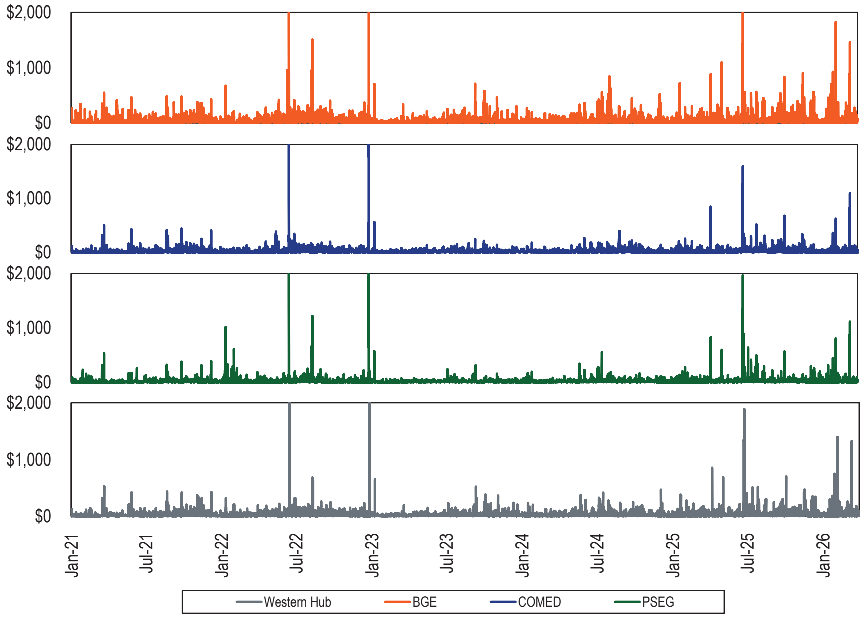
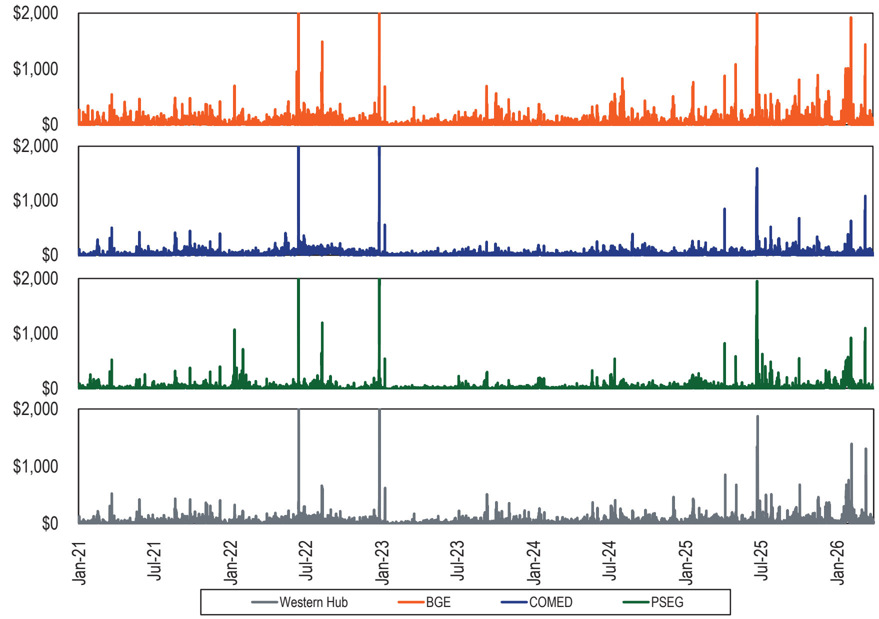


Figure 7-3 Hourly dark spread (coal) for peak hours ($/MWh): 2021 through March 2026[5]



Theoretical Energy Market Net Revenue

The net revenues presented in this section are theoretical as they are based on explicitly stated assumptions about how a new unit with specific characteristics would operate under economic dispatch. The economic dispatch uses technology specific operating constraints in the calculation of a new unit's operations and potential net revenue in PJM markets.

Analysis of energy market net revenues for a new unit includes eight power plant configurations:

4 Spark spreads use a combined cycle heat rate of 7,000 Btu/kWh, zonal hourly LMPs and daily gas prices; Chicago City Gate for COMED, Zone 6 non-NY for BGE, Zone 6 NY for PSEG, and Texas Eastern M3 for Western Hub.

5 Dark spreads use a heat rate of 10,000 Btu/kWh, zonal hourly LMPs, daily coal prices, and average transportation costs by coal type; Powder River Basin coal for COMED, Northern Appalachian coal for BGE and Western Hub, and Central Appalachian coal for PSEG.

- The CT plant is a single GE Frame 7HA.03 CT with an installed capacity of 409.3 MW, equipped with evaporative coolers, and selective catalytic reduction (SCR) for NO_x reduction, and dual fuel capability.
- The CC plant includes two single shaft 1x1 GE Frame 7HA.02 CTs, each with a single combustion turbine, heat recovery steam generator, and steam turbine with a total installed capacity of 1,362 MW, equipped with SCR for NO_x reduction, dry cooling, duct burners, and dual fuel capability.
- The CP is a subcritical steam unit with an installed capacity of 600.0 MW, equipped with selective catalytic reduction system (SCR) for NO_x control, a flue gas desulphurization (FGD) system with chemical injection for SO_x and mercury control, and a baghouse for particulate control.
- The DS plant is a single oil fired CAT 2 MW unit with an installed capacity of 2.0 MW using New York Harbor ultra low sulfur diesel.
- The nuclear plant includes two units and related facilities using the Westinghouse AP1000 technology with an installed capacity of 2,200 MW.
- The onshore wind installation includes 94 Siemens 3.2 MW wind turbines with an installed capacity of 300.8 MW.
- The offshore wind installation includes of 37 Siemens 11.0 MW wind turbines with an installed capacity of 406.0 MW.
- The solar installation is a 1,120 acre ground mounted tracking solar farm with an installed AC capacity of 200 MW.
- The battery storage unit is a 200 MW, 4 hour battery capable of providing 200 MW for 4 hours, or 800 MWh.

Net revenue calculations for the CT, CC and CP include the hourly effect of actual local ambient air temperature on plant heat rates and generator output for each of the three plant configurations.[6] [7] Plant heat rates account for the efficiency changes and corresponding cost changes resulting from ambient air temperatures.

CO_2, NO_x and SO_2 emission allowance costs are included in the hourly plant dispatch cost, the short run marginal cost.[8] CO_2, NO_x and SO_2 emission allowance costs were obtained from daily spot cash prices.[9]

The class average equivalent availability factor for each type of plant was calculated from PJM data and incorporated into all revenue calculations.[10]

Zonal net revenues reflect average zonal LMP, and fuel costs based on locational fuel indices and zone specific fuel delivery charges.[11] The delivered fuel cost for natural gas reflects the zonal, daily delivered price of natural gas from a specific pipeline and is from published commodity daily cash prices, with a basis adjustment for transportation costs.[12] The delivered cost of coal reflects the zone specific, delivered price of coal and was developed from the published prompt month prices, adjusted for rail transportation costs.[13] Net revenues are calculated for all zones except OVEC.[14]

Short run marginal cost includes fuel costs, emissions costs, and the short run marginal component of VOM costs.[15] [16] Starting in 2025, energy market offers include major maintenance costs. For the CT unit, the unit is dispatched with a start cost of $36,699/start. For the CC and CP unit, major maintenance is included as a cost per MWh. Unit costs used to dispatch the unit are shown, including all components, in Table 7-3.

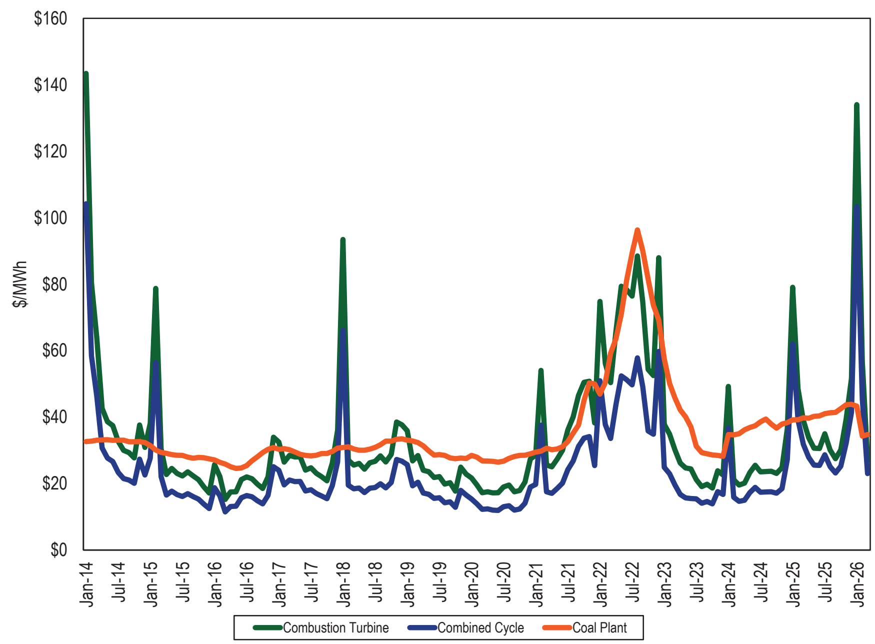
6 Hourly ambient conditions supplied by DTN.
7 Heat rates provided by Pasteris Energy, Inc. No load costs are included in the dispatch price since each unit type is dispatched at full load for every economic hour resulting in a single offer point.
8 CO_2 emission allowance costs only included for states participating in RGGI.
9 CO_2, NO_x and SO_2 emission daily prompt prices obtained from Evolution Markets, Inc.
10 Outage figures obtained from the PJM eGADS database.
11 Startup fuel burns and emission rates provided by Pasteris Energy, Inc. Startup station power consumption costs were obtained from the station service rates published quarterly by PJM and netted against the MW produced during startup at the preceding applicable hourly LMP. All starts associated with combined cycle units are assumed to be warm starts.
12 Gas daily cash prices obtained from Platts.
13 Coal prompt month prices obtained from Platts.
14 The Ohio Valley Electric Corporation (OVEC) includes a generating plant in Ohio and a generating plant in Indiana, and high voltage transmission lines, but does not occupy a single geographic footprint like the other control zones.
15 Fuel costs are calculated using the daily spot price and may not equal what individual participants actually paid
16 VOM rates provided by Pasteris Energy, Inc.

Table 7-3 Average operating costs: January through March, 2026

Unit Type	Operating Costs ($/MWh)	Heat Rate (Btu/kWh)	VOM ($/MWh)	Major Maintenance ($/MWh)	Start Costs ($/Start)
CT	$72.63	9,241	$0.43	$0.00	$36,669
CC	$57.29	6,369	$0.64	$2.88	$0
CP	$37.46	9,250	$5.09	$1.01	$0
DS	$215.80	9,660	$0.25	$0.00	$0
Nuclear	$0.00	NA	$0.00	$0.00	$0
Wind	$0.00	NA	$0.00	$0.00	$0
Wind (off shore)	$0.00	NA	$0.00	$0.00	$0
Solar	$0.00	NA	$0.00	$0.00	$0

A comparison of the monthly average operating cost of the theoretical CT, CC and CP plants since 2014 shows that, on average, the short run marginal costs of the CT plant and the CC plant have been less than those of the CP plant but the costs of the CT plant and the CC plant have been more volatile than the costs of the CP plant as a result of the higher volatility of gas prices compared to coal prices (Figure 7-4). The average monthly operating costs of a new CC and CT were greater than the marginal cost of a new CP in January and February 2026, but not in March. Marginal costs are based on spot fuel costs. Individual generation plants may have contracts for coal that differ significantly from spot prices.

Figure 7-4 Average short run marginal costs: 2014 through March 2026



The net revenue measure does not include the potentially significant contribution from the explicit or implicit sale of the option value of physical units or from bilateral agreements to sell output at a price other than the PJM day-ahead or real-time energy market prices, e.g., a forward price.

Gas prices, coal prices, and energy prices are reflected in new unit capacity factors. Table 7-4 shows the average capacity factor for new units. The capacity factors for a new CT, a new CC, and a new CP increased in the first three months of 2026 compared to the first three months of 2025.

Table 7-4 Average capacity factor: 2014 through March 2026

Jan-Mar	CT	CC	CP	DS	Nuclear	On Shore Wind	Solar
2014	44%	69%	74%	11%	91%	33%	11%
2015	61%	74%	67%	8%	92%	32%	13%
2016	74%	79%	43%	1%	92%	33%	14%
2017	51%	73%	41%	0%	94%	34%	13%
2018	58%	80%	40%	7%	94%	37%	13%
2019	47%	79%	27%	1%	93%	33%	13%
2020	53%	80%	6%	0%	93%	31%	12%
2021	38%	78%	33%	2%	93%	31%	12%
2022	37%	71%	36%	1%	92%	33%	14%
2023	43%	70%	5%	0%	94%	34%	13%
2024	57%	78%	27%	0%	92%	31%	14%
2025	50%	67%	48%	2%	92%	36%	15%
2026	71%	74%	50%	15%	92%	32%	14%

New Entrant Combustion Turbine

Energy market net revenue was calculated for a new CT plant economically dispatched by PJM. It was assumed that the CT plant had a minimum run time of two hours. The unit was first committed day ahead in profitable blocks of at least two hours, including start costs. If the unit was not already committed day ahead, it was run in real time in standalone profitable blocks of at least two hours, or any additional profitable hours bordering the profitable day-ahead or real-time block.

The new entrant CT is larger and more efficient than most CTs currently operating in PJM. The new entrant CT energy market net revenue results must therefore be interpreted carefully when comparing to existing CTs which are generally smaller and less efficient than the newest CT technology used by the new entrant CT.

New entrant CT plant energy market net revenues were higher in all zones in the first three months of 2026 as a result of higher spark spreads (Table 7-5).

Table 7-5 Energy net revenue for a new entrant gas fired CT under economic dispatch: January through March, 2014 through 2026 (Dollars per installed MW-year)[17]

	Jan-Mar													
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Change in 2026 from 2025
ACEC	$37,754	$12,776	$9,793	$5,094	$6,806	$7,471	$971	$2,519	$11,918	$1,695	$3,835	$1,963	$13,480	587%
AEP	$54,108	$28,204	$17,445	$8,061	$29,985	$9,977	$8,681	$7,386	$18,450	$12,380	$15,404	$22,217	$51,757	133%
APS	$67,470	$45,378	$13,746	$6,445	$36,990	$5,997	$2,111	$7,015	$12,276	$4,577	$20,649	$30,618	$111,319	264%
ATSI	$35,579	$23,015	$15,204	$8,790	$37,051	$10,895	$8,913	$9,488	$17,233	$10,038	$21,444	$26,129	$58,474	124%
BGE	$43,148	$12,147	$19,132	$8,307	$12,933	$5,766	$2,798	$8,385	$13,858	$4,775	$9,915	$11,737	$78,559	569%
COMED	$22,324	$11,462	$8,184	$3,957	$10,373	$4,047	$4,209	$3,279	$8,827	$5,801	$11,047	$9,241	$17,705	92%
DAY	$32,065	$20,233	$15,044	$7,517	$31,940	$11,113	$10,418	$13,494	$20,461	$11,963	$24,520	$25,157	$65,831	162%
DOM	$39,668	$16,211	$18,598	$7,708	$15,105	$7,316	$5,139	$6,897	$14,534	$9,912	$12,217	$14,128	$64,275	355%
DPL	$38,694	$12,217	$6,240	$3,796	$6,485	$3,500	$502	$11,557	$17,751	$3,812	$4,333	$5,544	$24,828	348%
DUKE	$29,200	$17,892	$14,061	$6,192	$38,188	$9,490	$8,904	$12,405	$18,741	$10,707	$22,062	$21,680	$62,346	188%
DUQ	$14,592	$9,130	$14,864	$4,724	$8,098	$3,872	$4,217	$4,285	$5,038	$8,827	$11,083	$7,158	$16,866	136%
EKPC	$49,038	$21,659	$15,107	$6,595	$20,778	$8,411	$7,595	$7,901	$18,881	$10,591	$15,102	$16,291	$33,221	104%
JCPLC	$41,229	$14,179	$7,559	$6,342	$7,018	$6,376	$990	$2,333	$10,957	$1,279	$3,807	$2,407	$15,017	524%
MEC	$41,388	$20,993	$13,828	$7,711	$11,234	$5,616	$5,731	$5,579	$19,247	$8,363	$11,150	$7,711	$15,972	107%
PE	$81,671	$58,960	$24,023	$9,259	$38,540	$10,088	$8,218	$11,934	$32,468	$16,618	$27,356	$37,168	$66,714	79%
PECO	$41,809	$20,891	$12,766	$6,174	$9,570	$5,030	$4,413	$3,208	$13,760	$3,414	$6,085	$4,824	$14,217	195%
PEPCO	$46,885	$13,007	$10,982	$6,099	$11,383	$4,754	$1,679	$5,131	$11,822	$3,399	$6,913	$8,807	$78,157	787%
PPL	$148,531	$84,974	$20,750	$10,291	$45,447	$7,185	$4,138	$8,804	$29,476	$11,364	$18,076	$23,259	$65,034	180%
PSEG	$52,790	$28,103	$15,489	$8,117	$10,758	$6,631	$1,107	$5,878	$14,460	$1,216	$4,564	$2,762	$15,679	468%
REC	$31,162	$16,289	$7,900	$5,640	$5,466	$5,443	$1,063	$11,775	$16,528	$2,421	$6,134	$3,939	$16,471	318%
PJM	$58,381	$24,386	$14,036	$6,841	$19,707	$6,949	$4,590	$7,463	$16,334	$7,158	$12,785	$14,137	$44,296	213%

New Entrant Combined Cycle

Energy market net revenue was calculated for a new CC plant economically dispatched by PJM. It was assumed that the CC plant had a minimum run time of four hours. The unit was first committed day ahead in profitable blocks of at least four hours, including start costs.[18] The unit was allowed to extend its run in real time if it was profitable to do so.

New entrant CC plant energy market net revenues were higher in all zones in the first three months of 2026 as a result of higher spark spreads (Table 7-6).

17 The energy net revenues presented for the PJM area in this section are calculated using the zonal average LMP.
18 All starts associated with combined cycle units are assumed to be warm starts.

Table 7-6 Energy net revenue for a new entrant CC under economic dispatch: January through March, 2014 through 2026 (Dollars per installed MW-year)[19]

	Jan-Mar													
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Change in 2026 from 2025
ACEC	$51,917	$21,960	$14,306	$11,375	$14,242	$15,408	$6,819	$5,979	$10,640	$2,590	$5,504	$8,289	$24,980	201%
AEP	$63,214	$35,476	$22,439	$14,388	$37,756	$18,967	$14,283	$15,052	$35,234	$23,401	$23,098	$31,097	$61,632	98%
APS	$79,776	$54,676	$25,811	$14,554	$46,949	$16,367	$11,146	$16,400	$26,257	$11,383	$29,802	$38,699	$116,074	200%
ATSI	$40,769	$31,458	$20,863	$14,986	$43,292	$19,794	$14,512	$18,167	$34,136	$21,081	$29,001	$34,230	$65,291	91%
BGE	$57,866	$21,830	$30,782	$16,487	$23,231	$15,669	$12,098	$17,573	$20,653	$12,285	$17,500	$20,906	$91,893	340%
COMED	$24,402	$18,254	$13,878	$8,627	$14,200	$9,662	$9,432	$7,621	$18,334	$13,220	$16,357	$14,917	$25,177	69%
DAY	$35,604	$28,773	$20,747	$14,010	$39,039	$20,098	$15,942	$22,208	$37,397	$23,344	$32,063	$33,488	$72,319	116%
DOM	$50,643	$25,250	$24,676	$14,431	$20,823	$16,407	$11,574	$14,918	$27,562	$21,155	$18,246	$25,295	$72,869	188%
DPL	$50,053	$18,656	$12,529	$5,832	$9,759	$4,873	$1,035	$12,599	$19,035	$5,009	$7,126	$13,113	$35,930	174%
DUKE	$31,977	$26,108	$19,795	$12,381	$44,259	$18,282	$14,548	$20,636	$35,334	$21,868	$29,446	$30,175	$69,010	129%
DUQ	$18,875	$12,222	$19,372	$10,714	$16,465	$10,886	$10,477	$10,658	$13,879	$19,823	$18,686	$13,999	$23,565	68%
EKPC	$57,036	$29,698	$20,355	$12,851	$29,400	$16,973	$13,540	$16,353	$34,287	$21,801	$23,306	$24,977	$47,064	88%
JCPLC	$57,370	$23,293	$12,163	$12,537	$14,412	$14,416	$6,985	$5,854	$8,413	$2,226	$5,935	$9,288	$26,754	188%
MEC	$52,805	$30,724	$17,860	$13,766	$19,939	$13,968	$11,572	$13,004	$23,692	$18,800	$19,340	$16,382	$31,291	91%
PE	$91,359	$59,225	$26,285	$15,380	$44,819	$19,147	$13,657	$20,663	$49,248	$27,081	$34,479	$45,274	$75,791	67%
PECO	$55,336	$32,397	$16,873	$12,277	$19,415	$12,909	$10,228	$9,982	$14,538	$10,883	$12,657	$12,747	$24,243	90%
PEPCO	$61,605	$23,012	$23,146	$13,829	$19,546	$14,156	$9,378	$11,412	$16,309	$7,647	$10,518	$18,539	$85,800	363%
PPL	$145,442	$78,794	$23,078	$15,942	$49,592	$14,995	$9,980	$16,706	$45,065	$21,615	$24,878	$30,920	$75,640	145%
PSEG	$72,991	$40,604	$19,821	$14,442	$21,129	$15,592	$7,789	$9,595	$10,796	$1,945	$6,971	$8,431	$26,958	220%
REC	$47,382	$23,878	$12,337	$11,761	$11,689	$13,869	$7,363	$13,360	$16,154	$3,396	$9,392	$10,786	$24,976	132%
PJM	$100,026	$31,814	$19,856	$13,029	$26,998	$15,122	$10,618	$13,937	$24,848	$14,527	$18,715	$22,078	$53,863	144%

New Entrant Coal Plant

Energy market net revenue was calculated for a new CP plant economically dispatched by PJM. It was assumed that the CP plant had a minimum run time of eight hours. The unit was first committed day ahead in profitable blocks of at least eight hours, including start costs. The unit was allowed to extend its run in real time if it was profitable to do so.

New entrant CP plant energy market net revenues were higher in all zones in the first three months of 2026 as a result of higher dark spreads (Table 7-7).

19 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

Table 7-7 Energy net revenue for a new entrant CP: January through March, 2014 through 2026 (Dollars per installed MW-year)[20]

	Jan-Mar													
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Change in 2026 from 2025
ACEC	$107,792	$40,142	$3,745	$1,178	$28,013	$3,213	$0	$3,211	$5,701	$1,201	$4,480	$11,650	$65,164	459%
AEP	$70,843	$23,058	$7,315	$8,104	$25,314	$5,842	$351	$12,337	$10,989	$182	$11,588	$33,748	$65,306	94%
APS	$82,000	$30,858	$1,920	$4,398	$26,869	$2,782	$0	$5,977	$6,193	$502	$9,419	$35,459	$105,611	198%
ATSI	$78,162	$24,868	$5,334	$9,185	$26,251	$5,642	$53	$9,672	$10,838	$231	$10,655	$32,270	$57,687	79%
BGE	$128,660	$45,329	$11,098	$4,976	$32,968	$3,458	$73	$9,554	$14,019	$1,848	$9,595	$21,079	$124,817	492%
COMED	$64,272	$19,375	$3,431	$6,920	$9,375	$5,332	$66	$10,349	$28,239	$10,727	$17,382	$26,749	$51,631	93%
DAY	$71,016	$23,143	$5,092	$7,464	$22,695	$5,662	$325	$14,065	$10,634	$170	$12,419	$33,170	$65,130	96%
DOM	$109,775	$50,579	$13,462	$5,084	$35,980	$5,116	$384	$11,383	$27,235	$2,531	$14,983	$43,456	$119,086	174%
DPL	$131,295	$53,979	$6,464	$3,809	$33,539	$4,046	$6	$11,384	$15,972	$2,625	$7,068	$18,235	$80,465	341%
DUKE	$65,469	$20,425	$4,336	$5,817	$27,387	$4,441	$101	$12,785	$9,633	$181	$11,784	$30,285	$62,024	105%
DUQ	$61,674	$16,396	$4,816	$7,965	$25,460	$4,699	$27	$8,965	$8,870	$205	$9,419	$28,862	$52,800	83%
EKPC	$65,433	$19,528	$3,750	$5,444	$16,902	$3,322	$55	$11,588	$10,416	$156	$11,453	$30,750	$63,095	105%
JCPLC	$112,807	$41,387	$2,170	$1,327	$28,138	$2,940	$0	$3,215	$6,930	$1,123	$4,468	$11,353	$66,416	485%
MEC	$124,027	$49,857	$4,409	$4,229	$33,221	$4,316	$525	$8,670	$27,403	$2,333	$12,249	$35,032	$81,811	134%
PE	$92,537	$38,559	$4,808	$3,194	$24,903	$3,599	$35	$9,517	$22,472	$1,506	$14,034	$40,268	$71,604	78%
PECO	$105,865	$39,385	$1,975	$1,169	$27,881	$2,761	$0	$4,481	$12,370	$1,478	$6,933	$19,126	$69,036	261%
PEPCO	$106,471	$32,196	$2,494	$1,062	$25,772	$1,733	$0	$5,175	$7,692	$1,646	$7,561	$17,185	$117,107	581%
PPL	$105,142	$38,500	$2,031	$1,309	$27,030	$1,634	$0	$4,743	$12,199	$1,424	$6,940	$17,506	$73,344	319%
PSEG	$141,330	$60,005	$5,254	$3,272	$31,064	$4,276	$0	$4,396	$14,469	$1,102	$4,952	$11,985	$68,004	467%
REC	$138,906	$61,121	$4,860	$3,287	$29,033	$4,966	$0	$8,166	$17,485	$1,312	$5,787	$13,051	$68,326	424%
PJM	$98,174	$36,434	$4,938	$4,459	$26,890	$3,989	$100	$8,482	$13,988	$1,624	$9,658	$25,561	$76,423	199%

New Entrant Nuclear Plant

Energy market net revenue was calculated assuming that the nuclear plant was dispatched day ahead by PJM for all available plant hours. The unit runs for all hours and output reflects the class average equivalent availability factor.[21]

New entrant nuclear plant energy market net revenues were higher in all zones in the first three months of 2026 as a result of higher quark spreads (Table 7-8).

20 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.
21 The annual class average equivalent availability factor was used in the calculation of energy market net revenues.

Table 7-8 Energy net revenue for a new entrant nuclear plant: January through March, 2014 through 2026 (Dollars per installed MW-year)[22]

	Jan-Mar													
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Change in 2026 from 2025
ACEC	$211,846	$115,640	$48,725	$58,221	$94,760	$60,423	$37,593	$55,190	$102,930	$56,927	$55,917	$98,494	$158,191	61%
AEP	$138,944	$79,965	$52,917	$58,719	$81,608	$58,767	$40,931	$61,127	$98,835	$63,536	$60,622	$97,370	$144,498	48%
APS	$160,110	$97,683	$55,589	$60,569	$92,244	$60,182	$40,555	$60,590	$104,382	$65,867	$62,706	$102,770	$200,294	95%
ATSI	$147,452	$81,034	$52,730	$60,761	$85,634	$60,612	$41,365	$60,525	$97,928	$63,827	$61,128	$98,592	$138,185	40%
BGE	$221,336	$117,188	$72,903	$67,346	$105,209	$64,215	$43,501	$68,896	$119,282	$73,785	$70,433	$117,280	$236,744	102%
COMED	$121,565	$67,311	$47,298	$54,992	$57,591	$52,559	$38,015	$57,449	$80,606	$54,163	$52,802	$69,678	$101,088	45%
DAY	$138,517	$77,939	$52,634	$59,527	$80,788	$60,909	$42,956	$65,079	$101,345	$66,272	$64,247	$97,389	$145,593	49%
DOM	$190,797	$112,959	$62,378	$63,021	$102,639	$62,157	$40,958	$63,882	$117,847	$70,088	$67,860	$114,205	$218,411	91%
DPL	$224,316	$126,346	$61,073	$63,399	$100,951	$60,325	$38,079	$69,344	$114,601	$58,926	$57,725	$103,576	$171,417	65%
DUKE	$131,887	$74,773	$51,588	$57,464	$86,563	$58,821	$41,383	$63,281	$99,134	$64,682	$61,540	$93,643	$141,783	51%
DUQ	$127,759	$70,888	$52,008	$59,245	$84,336	$58,959	$41,119	$58,969	$94,431	$62,450	$58,645	$94,200	$131,469	40%
EKPC	$131,844	$73,721	$50,862	$56,994	$72,894	$57,057	$40,988	$61,600	$100,027	$63,735	$60,692	$94,241	$142,534	51%
JCPLC	$218,343	$116,586	$46,100	$59,689	$94,793	$59,323	$37,785	$54,901	$106,644	$57,806	$56,743	$100,455	$161,091	60%
MEC	$207,794	$111,544	$46,218	$59,539	$95,281	$59,162	$38,361	$57,647	$115,503	$63,277	$61,832	$103,155	$165,234	60%
PE	$170,103	$98,672	$50,863	$58,911	$87,072	$59,494	$39,506	$59,862	$109,907	$64,444	$66,000	$110,021	$156,262	42%
PECO	$209,402	$114,373	$45,162	$57,657	$94,548	$57,937	$36,838	$54,446	$102,865	$54,644	$54,082	$96,681	$155,165	60%
PEPCO	$217,980	$114,824	$65,798	$65,002	$102,966	$63,377	$42,283	$65,197	$117,467	$71,732	$69,283	$117,043	$238,678	104%
PPL	$208,338	$113,104	$46,485	$59,062	$91,735	$55,819	$36,183	$55,245	$105,871	$58,668	$55,041	$94,795	$160,245	69%
PSEG	$234,034	$124,111	$48,419	$60,394	$97,373	$61,330	$37,947	$60,042	$112,895	$59,048	$57,877	$100,779	$164,057	63%
REC	$231,133	$125,393	$47,495	$60,714	$94,786	$61,717	$38,526	$66,729	$120,425	$62,811	$64,030	$108,364	$168,285	55%
PJM	$182,175	$100,703	$52,862	$60,061	$90,189	$59,657	$39,744	$61,000	$106,146	$62,834	$60,960	$100,637	$164,961	64%

New Entrant Diesel

Energy market net revenue was calculated for a DS plant economically dispatched by PJM in real time.

New entrant DS plant energy market net revenues were higher in all zones in the first three months of 2026 as a result of higher and more volatile energy prices (Table 7-9).

22 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues because fuel costs for nuclear units are included in the NEI nuclear costs.

Table 7-9 Energy market net revenue for a new entrant DS: January through March, 2014 through 2026 (Dollars per installed MW-year)

	Jan-Mar													
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Change in 2026 from 2025
ACEC	$32,171	$11,172	$1,895	$131	$9,687	$1,171	$19	$760	$5,193	$209	$512	$473	$21,059	4,356%
AEP	$14,072	$2,816	$316	$18	$3,182	$228	$121	$1,129	$526	$275	$322	$1,170	$14,673	1,154%
APS	$17,632	$6,050	$391	$64	$5,853	$225	$79	$718	$727	$284	$502	$2,622	$50,758	1,836%
ATSI	$13,724	$2,448	$256	$70	$2,327	$203	$127	$688	$524	$307	$245	$583	$7,889	1,254%
BGE	$48,591	$9,773	$2,207	$843	$11,091	$588	$226	$2,349	$3,729	$402	$1,307	$6,210	$68,827	1,008%
COMED	$11,036	$1,626	$152	$0	$603	$164	$96	$1,304	$392	$217	$218	$319	$4,471	1,302%
DAY	$13,842	$2,296	$269	$17	$1,401	$246	$143	$1,362	$531	$283	$573	$703	$11,161	1,489%
DOM	$42,074	$9,235	$1,282	$390	$13,183	$385	$145	$1,180	$3,572	$317	$1,732	$9,471	$74,173	683%
DPL	$35,919	$12,810	$1,670	$732	$11,197	$1,176	$19	$10,663	$6,142	$786	$957	$2,460	$32,052	1,203%
DUKE	$13,051	$1,892	$399	$11	$2,689	$207	$121	$1,597	$489	$268	$319	$618	$11,092	1,694%
DUQ	$12,607	$2,016	$255	$72	$2,615	$181	$152	$715	$511	$288	$244	$526	$7,208	1,271%
EKPC	$14,101	$2,087	$493	$10	$1,485	$205	$122	$1,861	$505	$270	$470	$1,470	$14,154	863%
JCPLC	$32,414	$11,631	$456	$209	$10,693	$1,131	$17	$707	$4,934	$221	$490	$456	$20,391	4,375%
MEC	$31,497	$10,905	$425	$167	$10,574	$357	$109	$903	$5,658	$261	$589	$788	$24,896	3,058%
PE	$15,656	$5,284	$266	$95	$4,610	$94	$145	$696	$618	$253	$320	$870	$15,941	1,732%
PECO	$31,741	$11,085	$421	$173	$9,516	$1,071	$21	$734	$5,107	$202	$544	$705	$22,984	3,162%
PEPCO	$50,549	$8,848	$1,182	$394	$11,047	$466	$168	$1,124	$3,910	$316	$1,489	$6,289	$75,337	1,098%
PPL	$32,438	$11,661	$397	$199	$8,376	$82	$23	$755	$2,701	$243	$483	$573	$23,182	3,947%
PSEG	$31,987	$11,287	$520	$205	$9,756	$1,481	$19	$1,131	$5,266	$219	$488	$502	$20,393	3,960%
REC	$29,526	$12,515	$507	$200	$8,823	$1,325	$21	$5,124	$5,167	$220	$472	$1,091	$19,580	1,695%
PJM	$29,787	$7,372	$688	$200	$6,935	$549	$94	$1,775	$2,810	$292	$614	$1,895	$27,011	1,326%

New Entrant Onshore Wind Installation

Energy market net revenues for an onshore wind installation were calculated hourly by zone assuming the unit generated at the average hourly capacity factor of all operating wind units in the zone with an installed capacity greater than 3 MW.[23]

Onshore wind energy market net revenues excluding RECs in the AEP, APS, and PE were higher in the first three months of 2026 as a result of increases in energy prices.

23 Net revenues are calculated for zones in which there are sufficient operating units to determine capacity factor for a new entrant unit.

Table 7-10 Energy market net revenue for an onshore wind installation (Dollars per installed MW-year): January through March, 2014 through 2026

	Jan-Mar													
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Change in 2026 from 2025
AEP	$45,406	$26,566	$21,777	$22,697	$38,566	$23,727	$13,525	$18,024	$35,754	$23,155	$22,084	$39,107	$46,732	19%
APS	$53,819	$33,489	$19,391	$24,579	$39,477	$19,314	$13,487	$17,251	$33,236	$23,017	$21,296	$43,231	$77,277	79%
COMED	$39,397	$23,379	$16,746	$21,821	$24,103	$20,127	$11,754	$18,216	$27,570	$19,795	$17,750	$24,848	$24,114	(3%)
PE	$66,094	$43,528	$21,076	$25,331	$41,510	$20,090	$12,783	$17,270	$34,758	$20,404	$18,162	$38,003	$45,569	20%

Wind units in the four zones were assumed to receive the higher of the MD or PA Tier I REC for the purposes of calculating RECs revenue.[24] Renewable energy credits were between 27 and 89 percent of the total energy market net revenue of an onshore wind installation.

Table 7-11 RECs revenue for an onshore wind installation (Dollars per installed MW-year): January through March, 2014 through 2026

	Jan-Mar													
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Change in 2026 from 2025
AEP	$11,245	$11,601	$10,807	$3,988	$5,573	$5,660	$7,027	$10,523	$19,155	$25,788	$27,310	$23,458	$19,706	(16%)
APS	$12,105	$11,296	$8,733	$4,082	$4,964	$4,448	$6,781	$10,144	$15,933	$24,475	$24,840	$24,124	$20,576	(15%)
COMED	$13,057	$11,750	$9,231	$4,222	$5,422	$5,498	$6,991	$12,050	$19,583	$26,724	$29,488	$25,441	$21,496	(16%)
PE	$13,521	$13,483	$9,992	$4,320	$5,359	$4,772	$6,727	$10,600	$16,356	$22,305	$20,366	$20,531	$16,467	(20%)

New Entrant Offshore Wind Installation

Energy market net revenues for an offshore wind installation were calculated hourly for relevant zones assuming the unit generated at a 40 percent capacity factor.

Offshore wind energy market net revenues excluding RECs were higher in the first three months of 2026 as a result of higher energy prices.

Table 7-12 Energy market net revenue for an offshore wind installation (Dollars per installed MW-year): January through March, 2014 through 2026

	Jan-Mar													
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Change in 2026 from 2025
ACEC	$85,651	$48,092	$21,071	$24,600	$40,720	$26,205	$16,368	$22,664	$47,210	$22,908	$23,108	$39,968	$61,702	54%
DOM	$88,644	$45,463	$25,403	$26,668	$45,330	$25,880	$17,241	$27,419	$51,619	$28,667	$28,684	$52,561	$95,236	81%
DPL	$91,499	$52,339	$24,464	$26,906	$43,334	$25,814	$16,556	$33,490	$54,108	$24,587	$23,238	$42,434	$67,958	60%

24 RECs prices obtained from Evolution Markets, Inc.

The offshore wind unit in ACEC was assumed to receive NJ wind RECs. The offshore wind unit in DOM and DPL was assumed to receive the higher of the MD or PA Tier I REC for the purposes of calculating RECs revenue.[25] Renewable energy credits were between 22 and 38 percent of the total energy market net revenue of an offshore wind installation.

Table 7-13 RECs revenue for an offshore wind installation (Dollars per installed MW-year): January through March, 2014 through 2026

	Jan-Mar													
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Change in 2026 from 2025
ACEC	$13,819	$13,997	$10,451	$4,420	$5,441	$5,750	$8,428	$13,421	$20,265	$27,726	$31,482	$24,530	$23,588	(4%)
DOM	$13,718	$13,716	$10,180	$4,212	$5,243	$5,715	$8,375	$13,419	$20,340	$27,294	$30,296	$23,640	$21,158	(10%)
DPL	$13,718	$13,716	$10,180	$4,212	$5,243	$5,715	$8,375	$13,419	$20,340	$27,294	$30,296	$23,640	$21,158	(10%)

New Entrant Solar Installation

Energy market net revenues for a solar installation were calculated hourly assuming the unit was generating at the average hourly capacity factor of operating solar units in the zone with an installed capacity greater than 3 MW.[26]

Solar energy market net revenues excluding RECs in the first three months of 2026 were higher in ACEC, DOM, and DPL as a result of higher energy prices. Solar energy market net revenues excluding RECs in the first three months of 2026 were lower in JCPLC and PSEG as a result of lower capacity factors.

Table 7-14 Energy market net revenue for a solar installation (Dollars per installed MW-year): January through March, 2014 through 2026

	Jan-Mar													
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Change in 2026 from 2025
ACEC	$21,536	$13,316	$5,993	$6,914	$10,062	$7,282	$4,438	$5,187	$11,826	$5,528	$5,009	$11,211	$11,887	6%
DOM	-	-	$11,030	$12,432	$16,098	$10,274	$6,915	$9,150	$19,472	$10,914	$10,293	$22,543	$29,440	31%
DPL	-	-	$8,621	$9,593	$12,531	$8,845	$5,452	$7,086	$13,396	$7,862	$6,346	$12,880	$19,039	48%
JCPLC	$20,041	$10,930	$4,953	$6,140	$8,959	$6,448	$3,984	$4,666	$10,983	$5,145	$4,191	$9,704	$7,977	(18%)
PSEG	$19,380	$14,236	$6,048	$6,760	$10,192	$7,759	$4,895	$6,894	$13,527	$5,994	$4,809	$10,942	$9,019	(18%)

The solar installation was assumed to receive the highest of the DC, MD or NJ Solar REC, based on locational eligibility, for the purposes of calculating RECs revenue.[27] Renewable energy credits were between 66 and 479 percent of the total energy market net revenue of a solar installation.

25 RECs prices obtained from Evolution Markets, Inc.
26 Net revenues are calculated for zones in which there are sufficient operating units to determine capacity factor for a new entrant unit.
27 RECs prices obtained from Evolution Markets, Inc.

Table 7-15 RECs revenue for a solar installation (Dollars per installed MW-year): January through March, 2014 through 2026

	Jan-Mar													
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Change in 2026 from 2025
ACEC	$41,783	$61,011	$77,407	$58,852	$58,108	$63,190	$58,863	$60,395	$64,866	$55,709	$58,796	$62,129	$48,766	(22%)
DOM	-	-	$20,073	$4,500	$3,647	$18,748	$29,338	$26,295	$25,413	$22,702	$24,553	$25,320	$19,377	(23%)
DPL	-	-	$17,082	$3,595	$2,869	$17,161	$24,688	$24,457	$17,899	$20,519	$19,775	$18,938	$14,800	(22%)
JCPLC	$40,306	$48,240	$63,743	$51,389	$52,376	$56,826	$52,807	$56,603	$58,249	$51,629	$49,391	$53,886	$38,183	(29%)
PSEG	$35,001	$54,050	$76,049	$56,814	$57,974	$64,597	$64,327	$62,180	$65,401	$58,461	$54,099	$56,948	$38,808	(32%)

Historical New Entrant CC Revenue Adequacy

Total unit net revenues include energy and capacity market revenues. Analysis of the total unit revenues of theoretical new entrant CCs for three representative locations shows that CC units that entered the PJM markets in 2007 have covered 94 percent of their total costs in the BGE Zone, 82 percent of their total costs in the PSEG Zone, and 52 percent of their total costs in the COMED Zone, including the return on and of capital, on a cumulative basis through March 2026. The analysis also shows that theoretical new entrant CCs that entered the PJM markets in 2012 have covered over 100 percent of their total costs on a cumulative basis in the BGE Zone, 93 percent of their total costs in PSEG Zone, and 65 percent of their total costs in the COMED Zone. Energy market revenues alone were not sufficient to cover total costs in any scenario, which demonstrates the critical role of the capacity market revenue in covering total costs. Covering 100 percent of total costs in this analysis includes earning the assumed rate of return. It is equivalent to being paid gross CONE, calculated using the defined parameters including the cost of capital. Units earned a positive rate of return even when earning less than the rate of return used in the gross CONE calculation.

Under cost of service regulation, units are guaranteed that they will cover their total costs, assuming that the costs were determined to be reasonable. To the extent that units built in the PJM markets did not cover their total costs, investors were worse off and customers were better off than under cost of service regulation, ignoring the benefits of competition on increasing efficiency, reducing costs and improving technology and ignoring the possibility of over earning under cost of service regulation.

Figure 7-5 compares cumulative energy market net revenues and energy market net revenues plus capacity market revenues to cumulative levelized costs for a new entrant CC that began operation on January 1, 2007, and a new entrant CC that began operation on January 1, 2012. The solid black line shows the total net revenue required to cover total costs. The solid colored lines show net energy revenue by zone. The dashed colored lines show the sum of net energy and capacity revenue by zone.

Figure 7-5 Historical new entrant CC revenue adequacy: 2007 through March 2026 and 2012 through March 2026 [28]

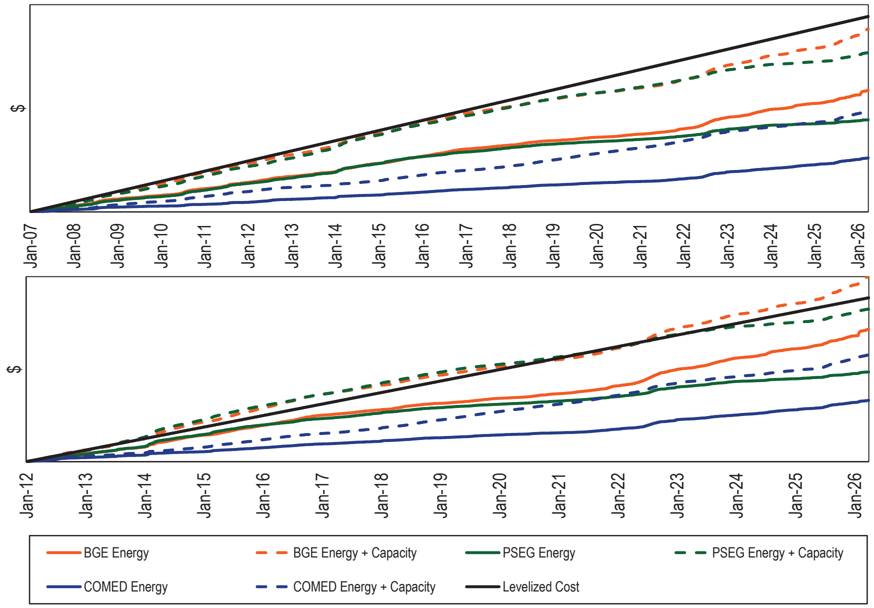


Table 7-16 shows the percent of levelized total costs recovered from the start date through March 2026. Table 7-16 also shows the return (IRR) earned from the start date through March 2026. For example, for a CC built in BGE in 2012, the resource would have earned a 14 percent IRR compared to the 12 percent used in the gross CONE calculation. In contrast, for a CC built in ComEd in 2012, the resource would have earned a 2 percent IRR compared to the 12 percent used in the gross CONE calculation.

Table 7-16 Percent of levelized total costs recovered

2007 through March 2026 and 2012 through March 2026	2007 CC	2012 CC
Percent of levelized costs covered at 12% IRR		
BGE	94%	113%
COMED	52%	65%
PSEG	82%	93%
IRR at which levelized costs are covered		
BGE	9%	14%
COMED	0%	2%
PSEG	7%	11%

The assumptions used for this analysis are shown in Table 7-17.

Table 7-17 Assumptions for analysis of new entry in 2007 and 2012

	2007 CC	2012 CC
Project Cost	$658,598,000	$665,995,000
Fixed O&M ($/MW-Year)	$20,016	$20,126
End of Life Value	$0	$0
Loan Term	20 years	20 years
Percent Equity (%)	50%	50%
Percent Debt (%)	50%	50%
Loan Interest Rate (%)	7%	7%
Cost of Equity (%)	12.0%	12.0%
Federal Income Tax Rate (%)	35%	35%
State Income Tax Rate (%)	9%	9%
General Escalation (%)	2.5%	2.5%
Technology	GE Frame 7FA.04	GE Frame 7FA.05
ICAP (MW)	601	655
Depreciation MACRS 150% declining balance	20 years	20 years
IRR (%)	12.0%	12.0%

Cost to Build vs Cost to Acquire

The MMU presented the cost to buy a new CT and a new CC during the Quadrennial Review process in 2025. (See Table 7-18.)

28 The gas pipeline pricing points used in this analysis are Zone 6 non-NY for BGE, Chicago City Gate for COMED, and Texas Eastern M3 for PSEG.

Table 7-18 Capital cost build up of a new EMAAC CT and CC[29]

Capital Costs ($ in 000s)	Combustion Turbine	Combined Cycle
Plant Proper EPC	$424,390	$1,610,970
Electric Interconnect/System Upgrades	$13,616	$39,672
Gas Interconnect	$20,228	$28,216
Water and Sewer Connection	$0	$7,771
Equipment Spares	$6,567	$11,943
Initial Fuel and Other Inventory	$4,988	$9,977
Mobilization and Startup	$2,837	$7,041
Land Purchase/Land Reservation Payment	$2,866	$9,171
Construction Period/Upfront Land Lease	$0	$0
Decommissioning Bond Costs	$0	$0
Development Expenses	$8,208	$10,944
Legal Fees	$2,551	$3,279
Permits	$2,760	$3,690
Emission Reduction Credits	$43,122	$105,459
Financing Fees	$5,667	$20,175
Interest During Construction	$0	$0
Owner's Contingency	$10,610	$40,274
Sales Tax	$549	$1,910
Other	$0	$0
Total Project Overnight Cost-No IDC ($ in 000s)	$548,960	$1,910,493
Total Project Cost ($/kW)	$1,253	$1,345

Buying an existing resource is an alternative to buying a new unit. Selected recent transactions including gas plants or primarily thermal generation portfolios in the US with announced prices are shown in Table 7-19. Not all transactions are in PJM. Recent transactions for new combined cycles are close to or at a premium to the MMU estimate of total project cost in $/kW.

29 The MMU retained Pasteris Energy, Inc. to develop the revenue requirements of a new entrant ("Gross CONE") combustion turbine ("CT") and combined cycle ("CC") power plant located in five PJM Locational Deliverability Areas ("LDA") on a 2028 dollar basis for commercial operation in the 2028/2029 Delivery Year as part of the Quadrennial Review. Stantec Consulting Services, Inc. ("Stantec") a power plant design and engineering firm with CT and CC plant design experience was contracted by Pasteris Energy, Inc. to determine the plant proper capital cost estimate for the CONE CT and CC power plant at the five locations within PJM. The power plant construction estimates were developed based on data from recent actual construction proposals by Stantec and input obtained from multiple construction contractors. For these estimates, labor rates and labor productivity for each CONE Area were verified and used to develop the direct and indirect construction costs.

Table 7-19 Selected recent transactions[30]

Date Announced	Date Closed	Buyer	Seller	Description of Assets	Unit Type	Fuel	Location	Price ($ in millions)	MW	$/kW
1/15/2026	-	Talen Energy	Energy Capital Partners	Waterford (OH) Darby (OH) Lawrenceburg (IN)	1 Combustion Turbine 2 Combined Cycles	Natural Gas	IN, OH	$3,450	2,600	$1,327
1/5/2026	-	Vistra	Cogentrix (Quantum Capital Group)	10 units	2 Combustion Turbine 7 Combined Cycles 1 Cogeneration Unit	Natural Gas	CT, MD, ME, NH, NJ, PA, RI, TX	$4,000	5,500	$727
9/15/2025	-	Blackstone	Ardian	Hill Top Energy Center	1 Combined Cycle	Natural Gas	PA	$1,000	620	$1,613
9/15/2025	9/24/2025	CPS Energy	PROENERGY	4 units	4 Combustion Turbines	Natural Gas	TX	$1,387	1,632	$850
9/11/2025	9/11/2025	PowerTransitions (Partners Group)	Talen Energy	Camden Power Plant (NJ) Dartmouth Power Plant (MA)	2 Combustion Turbines	Natural Gas	NJ, MA	$450	226	$1,991
7/17/2025	11/25/2025	Talen Energy	Caithness, BlackRock	Guernsey Power Station (OH) Moxie Freedom Energy Center (PA)	2 Combined Cycles	Natural Gas	OH, PA	$3,500	2,941	$1,190
5/15/2025	10/22/2025	Vistra	Lotus Infrastructure Partners	7 units Greenleaf (CA) Garrison (DE) Beaver Falls (NY) Fairless (PA) Manchester (RI)	2 Combustion Turbines 5 Combined Cycles	Natural Gas	CA, DE, NY, PA, RI	$1,900	2,600	$731
5/12/2025	1/30/2026	NRG Energy	LS Power	18 units	18 units	Natural Gas	9 states in Northeast, TX	$12,000	13,000	$923
4/14/2025	6/9/2025	Capital Power	LS Power	Rolling Hills (OH) Hummel (PA)	2 Combined Cycles	Natural Gas	OH, PA	$2,200	2,147	$1,025
3/18/2025	6/16/2025	Partners Group	Middle River	Middle River portfolio 11 units	9 Combustion Turbines 2 Combined Cycle	Natural Gas	CA	$2,200	1,900	$1,158
3/12/2025	4/10/2025	NRG	Rockland Capital	6 units Victoria, Victoria Port II, SJRR, Port Comfort, Chamon, Wharton	5 Combustion Turbines 1 Combined Cycle	Natural Gas	TX	$560	738	$759
1/24/2025	8/5/2025	Blackstone	Ares Management	Potomac Energy Center	1 Combined Cycle	Natural Gas	VA	$1,000	774	$1,292
1/10/2025	1/7/2026	Constellation	Calpine	Calpine portfolio 79 units	79 units	Natural Gas Geothermal	USA	$26,600	27,000	$985
8/5/2024	1/31/2025	Quantum Capital Group	Carlyle	Cogentrix Energy 11 units	11 units	Natural Gas	MA, MD, ME, NH NJ, PA, RI, TX	$3,000	5,300	$566
6/28/2024	6/30/2025	AEP	J-Power USA	Green Country Power Plant	1 Combined Cycle	Natural Gas	OK	$730	795	$918
3/27/2024	5/1/2024	CPS Energy	Talen	Barney Davis, Nueces Bay, Laredo	1 Combustion Turbine 2 Combined Cycles	Natural Gas	TX	$785	1,710	$459
11/20/2023	2/9/2024 and 2/16/2024	Capital Power Corporation	CSG Investments	Harquahala (AZ) La Paloma (CA)	2 Combined Cycles	Natural Gas	AZ, CA	$1,100	1,608	$684
11/13/2023	9/29/2025	TotalEnergies	TexGen	Wolf Hollow I, Colorado Bend I, La Porte	1 Combustion Turbine 2 Combined Cycles	Natural Gas	TX	$635	1,500	$423
9/23/2021	9/30/2022	Alabama Power	Harbert Power Fund V	Calhoun Generating Facility	4 Combustion Turbines	Natural Gas	AL	$179	743	$241
8/13/2021	2/18/2022 and 2/23/2022	ArcLight Energy Partners Fund VII	PSEG	PSEG Fossil portfolio 13 units	13 units	Coal Natural Gas	NJ, CT, MD, NY	$1,920	6,750	$284
2/28/2021	12/1/2021	Generation Bridge (ArcLight Energy Partners Fund VII)	NRG Energy	8 units Sunrise, Long Beach (CA) Middletown, Montville, Devon, CT Jets (CT) Arthur Kill, Oswego (NY)	1 Combined Cycle 7 CT/Oil	Natural Gas, Oil	CA, CT, NY	$620	4,900	$127

30 All transaction information is public.

The average transaction price paid in $/kW has been generally increasing as shown in Table 7-20. There is a range in the data in part a result of the fact that some of the transactions include portfolios of resources and in part due to the relative ages of the acquired resources.

Table 7-20 Selected recent transactions price trends

Year Announced	Natural Gas Average $/kW
2026	$1,027
2025	$1,138
2024	$648
2023	$554

Nuclear Net Revenue Analysis

The analysis of nuclear plants includes annual avoidable costs and incremental capital expenditures from the Nuclear Energy Institute (NEI) based on NEI's calculations of average costs for all U.S. nuclear plants.[31] [32] The analysis includes the most recent operating cost data and incremental capital expenditure data for single unit plants and multi unit plants published by NEI, which is for 2023.[33] NEI average operating costs have decreased since their peak in 2012 (a 7.5 percent decrease from 2012 through 2023 for all plants including single and multiple unit plants in nominal dollars; a 33.0 percent decrease in real 2023 dollars).[34] NEI average incremental capital expenditures have decreased since their peak in 2012 (a 32.8 percent decrease from 2012 through 2023 for all plants including single and multiple unit plants in nominal dollars; a 51.1 percent decrease in real 2023 dollars).[35] NEI's incremental capital expenditures peaked in 2012 as a result of regulatory requirements following the 2011 accident at the Fukushima nuclear plant in Japan.

31 Operating costs from: Nuclear Energy Institute (February 2025). "Nuclear Costs in Context," <https://www.nei.org/resources/reports-briefs/nuclear-costs-in-context>. Individual plants may vary from the average due to factors such as geographic location, local labor costs, the timing of refueling outages and other unit specific factors. This is the most current NEI data available.

32 The NEI costs for Hope Creek were treated as that of a two unit configuration because the unit is located in the same area as Salem 1 & 2. The net surplus of Hope Creek is sensitive to the accuracy of this assumption.

33 NEI also provides average costs by plant run by operators with one plant or multiple plants, by market, and by type of nuclear reactor. Plants run by operators with multiple plants have lower average costs than plants run by operators with a single plant. Plants participating in wholesale markets have lower average costs than plants in regulated markets. PWR reactors have lower average generating costs than BWR reactors.

34 Operating costs in this paragraph are operating costs as specified by NEI and do not include fuel costs or capital expenditures. Operating costs for single unit plants decreased by 2.6 percent from 2022 to 2023 in nominal dollars. Operating costs for multiple unit plants increased by 6.0 percent from 2022 to 2023 in nominal dollars.

35 Capital expenditures have decreased 20.6 percent since 2012 for single unit plants and 35.0 percent for multiple unit plants in nominal dollars.

The results for nuclear plants are sensitive to small changes in PJM energy and capacity prices, both actual and forward prices.[36] When gas prices are high and LMPs are high as a result, net revenues to nuclear plants increase. In 2014, the polar vortex resulted in a significant increase in net revenues to nuclear plants. When gas prices are low and LMPs are low as a result, net revenues to nuclear plants decrease. In 2016, PJM energy prices were then at the lowest level since the introduction of competitive markets on April 1, 1999, and remained low in 2017. As a result, in 2016 and 2017, a significant proportion of nuclear plants did not cover annual avoidable costs based on current year prices.[37] In 2018, high gas prices and high LMPs resulted in a significant increase in net revenues for nuclear plants in PJM. Energy prices in 2018 were significantly higher than in 2017. Although energy prices in 2019 were lower than in 2016, higher capacity market revenues more than offset the difference. In 2020, PJM energy prices were at the lowest level since the introduction of competitive markets, even lower than in 2016. Average energy prices in 2022 were higher than energy prices in any year since the inception of PJM markets in 1999. Based on forward prices as of December 31, 2025, expected nuclear plant energy revenues for 2026, 2027 and 2028 are higher than actual revenues in all years since 2014, with the exception of 2022. The actual net revenue results for individual nuclear plants are a function of the degree to which actual unit costs are less than or greater than the benchmark NEI data.

Table 7-21 shows energy market prices, Table 7-22 and Table 7-23 show capacity market prices and Table 7-24 shows nuclear cost data for the 16 nuclear plants in PJM in addition to Oyster Creek, which retired September 17, 2018, and Three Mile Island, which retired September 20, 2019.[38] [39] The analysis excludes the Catawba 1 nuclear unit. Partial data is provided for the Cook, North Anna, and Surry nuclear units.[40] The AEP Cook nuclear units

36 A change in the capacity market price of $24 per MW-day translates into a change in capacity revenue of $1.00 per MWh for a nuclear power plant operating at a capacity factor of 100 percent. A change in the capacity market price of $24 per MW-day translates into a change in capacity revenue of $1.05 per MWh for a nuclear power plant operating at a capacity factor of 0.951 percent.

37 The MMU submitted testimony in New Jersey on the same issues of nuclear economics. *Establishing Nuclear Diversity Certificate Program*. Bill No. S-877 New Jersey Senate Environment and Energy Committee. (2018). *Revised Statement of Joseph Bowring*.

38 Installed capacity is from NEI fact sheets accessed April 23, 2025 <https://www.nei.org/resources/fact-sheets/u-s-nuclear-plants>.

39 Constellation plans to restore TMI Unit 1 to service. Exelon. "Constellation to Launch Crane Clean Energy Center, Restoring Jobs and Carbon-Free Power to The Grid," (September 20, 2024) <https://www.constellationenergy.com/newsroom/2024/Constellation-to-Launch-Crane-Clean-Energy-Center-Restoring-Jobs-and-Carbon-Free-Power-to-The-Grid.html>.

40 Capacity market revenues are not included for the FRR units because the units were not in the capacity market.

are designated FRR. North Anna 1 and 2 and Surry 1 and 2 were part of the Dominion FRR for the 2022/2023 and 2023/2024 and 2024/2025 Delivery Years.[41] [42] [43] FRR units receive cost of service revenues and are not subject to PJM market revenues. Duke's Catawba 1 is not in PJM but is pseudo tied to PJM.

For nuclear plants, all calculations are based on publicly available data in order to avoid revealing confidential information. Historical nuclear unit revenue is based on day-ahead LMP at the relevant node. Nuclear unit capacity revenue assumes that the unit cleared its full unforced capacity at the BRA locational clearing price. Unforced capacity is determined using the annual class average EFORd or ELCC rate.[44]

Table 7-21 Nuclear unit day-ahead LMP: 2008 through 2025

	ICAP	Average DA LMP ($/MWh)																	
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Beaver Valley	1,808	$49.46	$31.51	$35.59	$37.43	$30.34	$34.24	$41.86	$30.35	$27.07	$29.11	$36.35	$26.22	$20.33	$37.07	$67.02	$29.63	$30.28	$43.49
Braidwood	2,337	$48.10	$27.76	$31.48	$32.02	$27.51	$30.26	$37.34	$25.97	$24.30	$24.99	$27.11	$22.88	$18.23	$33.74	$58.20	$25.78	$23.31	$33.71
Byron	2,300	$47.61	$23.98	$28.49	$28.09	$24.25	$29.22	$35.05	$21.00	$17.94	$23.79	$26.96	$22.19	$17.66	$32.81	$57.70	$25.36	$23.74	$33.96
Calvert Cliffs	1,726	$78.63	$41.05	$51.27	$46.53	$35.19	$40.27	$57.88	$40.30	$32.64	$31.57	$38.79	$28.00	$21.88	$41.24	$78.11	$35.45	$37.05	$54.51
Cook	2,177	$52.26	$32.20	$36.52	$37.41	$30.09	$34.14	$40.49	$29.94	$26.93	$28.03	$31.44	$25.07	$19.59	$34.81	$63.46	$28.88	$28.28	$42.50
Davis Besse	894	-	-	-	$39.68	$31.68	$36.10	$47.21	$31.94	$27.80	$28.85	$34.44	$26.33	$20.54	$37.34	$68.07	$29.63	$30.46	$45.69
Dresden	1,797	$48.76	$28.27	$32.73	$33.07	$28.42	$31.82	$39.22	$27.45	$25.89	$26.35	$28.25	$23.41	$18.73	$34.32	$59.35	$25.11	$24.36	$33.93
Hope Creek	1,172	$73.34	$39.43	$48.03	$45.52	$33.07	$37.43	$51.99	$32.41	$23.20	$26.78	$32.93	$22.45	$17.32	$30.16	$60.64	$22.97	$26.42	$40.08
LaSalle	2,265	$47.96	$27.71	$31.53	$31.93	$27.56	$30.94	$37.88	$26.28	$23.95	$24.71	$27.19	$22.75	$18.14	$33.54	$57.90	$25.55	$23.05	$33.92
Limerick	2,242	$73.49	$39.49	$48.23	$45.27	$33.09	$37.28	$51.71	$32.65	$23.37	$26.99	$33.08	$22.68	$17.31	$31.05	$61.25	$23.16	$26.06	$39.97
North Anna	1,892	$75.14	$39.89	$50.59	$45.47	$33.87	$38.55	$53.37	$38.05	$30.50	$31.27	$38.44	$27.39	$21.06	$39.99	$76.51	$33.75	$35.11	$52.50
Oyster Creek	608	$75.49	$40.43	$49.29	$46.74	$33.69	$38.62	$52.85	$33.10	$23.79	$27.52	NA	NA	NA	NA	NA	NA	NA	NA
Peach Bottom	2,550	$73.09	$39.32	$47.70	$44.73	$32.81	$37.37	$51.52	$31.98	$23.07	$26.76	$32.63	$21.58	$16.93	$30.77	$61.29	$23.01	$26.08	$39.97
Perry	1,240	-	-	$36.99	$38.76	$31.68	$36.69	$46.14	$32.77	$27.84	$29.91	$37.24	$26.76	$20.49	$37.76	$68.56	$30.39	$31.23	$45.36
Quad Cities	1,819	$47.28	$24.81	$27.53	$26.79	$20.43	$25.94	$30.71	$19.47	$18.04	$23.09	$25.54	$21.13	$15.95	$31.39	$57.82	$25.01	$23.42	$34.53
Salem	2,285	$73.41	$39.51	$48.02	$45.50	$33.06	$37.40	$51.96	$32.37	$23.18	$26.76	$32.90	$22.43	$17.32	$30.12	$60.59	$22.95	$26.40	$40.04
Surry	1,676	$71.96	$39.02	$49.30	$45.01	$33.62	$37.98	$51.75	$37.91	$30.08	$31.08	$38.50	$26.65	$20.41	$39.30	$74.21	$32.74	$33.65	$49.76
Susquehanna	2,494	$69.96	$38.24	$45.95	$44.78	$32.10	$36.76	$50.93	$32.47	$23.66	$27.14	$32.42	$21.08	$16.03	$30.36	$59.60	$23.77	$24.13	$36.03
Three Mile Island	803	$72.46	$39.11	$46.72	$44.15	$32.43	$36.83	$50.47	$30.94	$22.96	$27.12	$31.76	NA	NA	NA	NA	NA	NA	NA

41 See "Resources Designated in 2022/2023 FRR Capacity Plans as of April 23, 2021," <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2022-2023/2022-2023-resources-designated-in-frr-plans.ashx>.
42 See "Resources Designated in 2023/2024 FRR Capacity Plans as of May 19, 2021," <https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2023-2024/2023-2024-resources-designated-in-frr-plans.pdf>.
43 See "Resources Designated in 2024/2025 FRR Capacity Plans as of November 8, 2022," <https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2024-2025/2024-2025-resources-designated-in-frr-plans.pdf>.
44 ELCC rates used starting with the 2025/2026 Delivery Year. See BRA Class Ratings <https://www.pjm.com/planning/resource-adequacy-planning/effective-load-carrying-capability>.

Table 7-22 BRA capacity market clearing prices ($/MW-Day): 2007/2008 through 2027/2028 [45] [46]

	ICAP	BRA Capacity Price ($/MW-Day)																				
	(MW)	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28
Beaver Valley	1,808	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$165	$100	$77	$140	$50	$34	$29	$270	$329	$333
Braidwood	2,337	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196	$69	$34	$29	$270	$329	$333
Byron	2,300	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196	$69	$34	$29	$270	$329	$333
Calvert Cliffs	1,726	$189	$210	$237	$174	$110	$133	$226	$137	$167	$119	$120	$165	$100	$86	$140	$96	$49	$49	$270	$329	$333
Cook	2,177	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Davis Besse	894	-	-	-	-	$109	$20	$28	$126	$357	$114	$120	$165	$100	$77	$171	$50	$34	$29	$270	$329	$333
Dresden	1,797	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196	$69	$34	$29	$270	$329	$333
Hope Creek	1,172	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	$166	$98	$49	$54	$270	$329	$333
LaSalle	2,265	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196	$69	$34	$29	$270	$329	$333
Limerick	2,242	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	$166	$98	$49	$54	$270	$329	$333
North Anna	1,892	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$165	$100	$77	$140	NA	NA	NA	$444	$329	$333
Oyster Creek	608	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	-	-	-	-	-	-	-
Peach Bottom	2,550	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	$166	$98	$49	$54	$270	$329	$333
Perry	1,240	-	-	-	-	$109	$20	$28	$126	$357	$114	$120	$165	$100	$77	$171	$50	$34	$29	$270	$329	$333
Quad Cities	1,819	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196	$69	$34	$29	$270	$329	$333
Salem	2,285	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	$166	$98	$49	$54	$270	$329	$333
Surry	1,676	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$165	$100	$77	$140	NA	NA	NA	$444	$329	$333
Susquehanna	2,494	$41	$112	$191	$174	$110	$133	$226	$137	$167	$119	$120	$165	$100	$86	$140	$96	$49	$49	$270	$329	$333
Three Mile Island	803	$41	$112	$191	$174	$110	$133	$226	$137	$167	$119	$120	$165	$100	$86	$140	-	-	-	-	-	-

45 Oyster Creek retired September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>. Three Mile Island retired September 20, 2019. Exelon. "Three Mile Island Generating Station Unit 1 Retires from Service After 45 Years," (September 20, 2019) <https://www.exeloncorp.com/newsroom/three-mile-island-generating-station-unit-1-retires>. For the 2022/2023 Delivery Year, Surry is part of Dominion FRR.

46 Cook is designated FRR. North Anna and Surry are in Dominion FRR beginning with the 2022/2023 Delivery Year. North Anna and Surry are in the PJM Capacity Market beginning with the 2025/2026 Delivery Year.

Table 7-23 Nuclear unit capacity market revenue ($/MWh): 2008 through 2027[47] [48]

	ICAP	Capacity Revenue ($/MWh)																			
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Beaver Valley	1,808	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$6.42	$5.61	$3.81	$4.93	$3.80	$1.76	$1.35	$7.40	$13.24	$14.42
Braidwood	2,337	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.20	$8.58	$8.35	$5.28	$2.10	$1.35	$7.40	$13.24	$14.42
Byron	2,300	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.20	$8.58	$8.35	$5.28	$2.10	$1.35	$7.40	$13.24	$14.42
Calvert Cliffs	1,726	$8.73	$9.59	$8.64	$5.87	$5.38	$8.21	$7.53	$6.74	$6.04	$5.26	$6.42	$5.62	$4.07	$5.10	$4.97	$2.97	$2.15	$7.77	$13.24	$14.42
Cook	2,177	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Davis Besse	894	NA	NA	NA	NA	$2.49	$1.08	$3.70	$11.40	$9.33	$5.17	$6.42	$5.61	$3.81	$5.73	$4.36	$1.76	$1.35	$7.40	$13.24	$14.42
Dresden	1,797	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.20	$8.58	$8.35	$5.28	$2.10	$1.35	$7.40	$13.24	$14.42
Hope Creek	1,172	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	$7.98	$7.24	$7.05	$7.59	$5.48	$3.00	$2.26	$7.84	$13.24	$14.42
LaSalle	2,265	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.20	$8.58	$8.35	$5.28	$2.10	$1.35	$7.40	$13.24	$14.42
Limerick	2,242	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	$7.98	$7.24	$7.05	$7.59	$5.48	$3.00	$2.26	$7.84	$13.24	$14.42
North Anna	1,892	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$6.42	$5.61	$3.81	$4.93	$2.52	NA	NA	$11.32	$16.38	$14.42
Oyster Creek	608	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	-	-	-	-	-	-	-	-	-	-
Peach Bottom	2,550	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	$7.98	$7.24	$7.05	$7.59	$5.48	$3.00	$2.26	$7.84	$13.24	$14.42
Perry	1,240	NA	NA	NA	NA	$2.49	$1.08	$3.70	$11.40	$9.33	$5.17	$6.42	$5.61	$3.81	$5.73	$4.36	$1.76	$1.35	$7.40	$13.24	$14.42
Quad Cities	1,819	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.20	$8.58	$8.35	$5.28	$2.10	$1.35	$7.40	$13.24	$14.42
Salem	2,285	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	$7.98	$7.24	$7.05	$7.59	$5.48	$3.00	$2.26	$7.84	$13.24	$14.42
Surry	1,676	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$6.42	$5.61	$3.81	$4.93	$2.52	NA	NA	$11.32	$16.38	$14.42
Susquehanna	2,494	$3.57	$6.72	$7.82	$5.87	$5.38	$8.21	$7.53	$6.74	$6.04	$5.26	$6.42	$5.61	$4.06	$5.10	$4.97	$2.97	$2.15	$7.77	$13.24	$14.42
Three Mile Island	803	$3.57	$6.72	$7.82	$5.87	$5.38	$8.21	$7.53	$6.74	$6.04	$5.26	$6.42	-	-	-	-	-	-	-	-	-

47 Capacity revenue through the 2024/2025 Delivery Year is calculated by adjusting the BRA Capacity Price for calendar year, by the class average EFORd, and by the annual class average capacity factor. Class average EFORd and capacity factor is from *2025 Annual State of the Market Report for PJM*, Volume 2, Section 5: Capacity Market. Capacity revenue beginning the 2025/2026 Delivery Year is calculated by adjusting the BRA Capacity Price for calendar year, by the class average ELCC. See BRA Class Ratings <https://www.pjm.com/planning/resource-adequacy-planning/effective-load-carrying-capability>.

48 Oyster Creek retired September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>. Three Mile Island retired September 20, 2019. Exelon. "Three Mile Island Generating Station Unit 1 Retires from Service After 45 Years," (September 20, 2019) <https://www.exeloncorp.com/newsroom/three-mile-island-generating-station-unit-1-retires>. Constellation is planning to restart Three Mile Island Unit 1. Constellation. "Constellation to Launch Crane Clean Energy Center, Restoring Jobs and Carbon-Free Power to The Grid," (September 20, 2024) <https://www.constellationenergy.com/newsroom/2024/Constellation-to-Launch-Crane-Clean-Energy-Center-Restoring-Jobs-and-Carbon-Free-Power-to-The-Grid.html>.

Table 7-24 Nuclear unit costs: 2008 through 2024[49] [50]

	ICAP		NEI Costs ($/MWh)															
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Beaver Valley	1,808	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18	$28.63	$29.53	$29.53
Braidwood	2,337	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18	$28.63	$29.53	$29.53
Byron	2,300	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18	$28.63	$29.53	$29.53
Calvert Cliffs	1,726	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18	$28.63	$29.53	$29.53
Cook	2,177	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18	$28.63	$29.53	$29.53
Davis Besse	894	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66	$42.00	$38.40	$39.64	$37.42	$41.08	$41.62	$41.62
Dresden	1,797	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18	$28.63	$29.53	$29.53
Hope Creek	1,172	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18	$28.63	$29.53	$29.53
LaSalle	2,265	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18	$28.63	$29.53	$29.53
Limerick	2,242	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18	$28.63	$29.53	$29.53
North Anna	1,892	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18	$28.63	$29.53	$29.53
Oyster Creek	608	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66	-	-	-	-	-	-	-
Peach Bottom	2,550	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18	$28.63	$29.53	$29.53
Perry	1,240	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66	$42.00	$38.40	$39.64	$37.42	$41.08	$41.62	$41.62
Quad Cities	1,819	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18	$28.63	$29.53	$29.53
Salem	2,285	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18	$28.63	$29.53	$29.53
Surry	1,676	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18	$28.63	$29.53	$29.53
Susquehanna	2,494	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18	$28.63	$29.53	$29.53

Hope Creek, Quad Cities, and Salem have all received state subsidies since 2019.[51] [52] The NJ Board of Public Utilities, having received no applications as of December 1, 2023, closed the third eligibility period of the ZEC program for the period beginning June 1, 2025.[53] This was a result of the introduction of a new federal nuclear subsidy under the Inflation Reduction Act. Braidwood, Byron, Dresden, and LaSalle will receive a state subsidy if necessary to meet a target net revenue value, in dollars per MWh, from the energy and capacity markets.[54] All existing nuclear plants will receive a federal subsidy if necessary to meet a target revenue value, in dollars per MWh, from the energy market.[55]

The Inflation Reduction Act added a significant new federal subsidy for existing nuclear power plants.[56] All existing nuclear plants will receive the Zero Emission Nuclear Power Production Credit (Nuclear PTC) if revenues from energy, ancillary, capacity markets, and any state subsidies are between $25.00/MWh and $43.75/MWh, adjusted for inflation. The Nuclear PTC of $3.00/MWh is increased by a factor of five to $15.00/MWh if certain prevailing wage requirements are

49 Operating costs from: Nuclear Energy Institute (February 2025). "Nuclear Costs in Context," <https://www.nei.org/resources/reports-briefs/nuclear-costs-in-context>. Operating Costs for 2024 and beyond are set equal to 2023 costs.

50 Oyster Creek retired on September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>. Three Mile Island retired September 20, 2019. Exelon. "Three Mile Island Generating Station Unit 1 Retires from Service After 45 Years," (September 20, 2019) <https://www.exeloncorp.com/newsroom/three-mile-island-generating-station-unit-1-retires>.

51 Illinois Commerce Commission, Report to the General Assembly in Compliance with Section 1-75(d-5) of the [CEJA, Public Act 102-0662,] 20 ILCS 3855/1-75(d-5)(F)(2) (August 2019). The report finds that while total ZECs payments are limited by rate impact caps and volume caps, the law's limitation does not unduly constrain the procurement of ZECs.

52 *Application of PSEG Nuclear, LLC for the Zero Emission Certificate Program – Hope Creek,* Order Determining the Eligibility of Hope Creek Nuclear Generator to Receive ZECs, BPU Docket No. ER20080559 (April 27, 2021). *Application of PSEG Nuclear, LLC for the Zero Emission Certificate Program – Salem 1*, Order Determining the Eligibility of Salem Unit 1 Nuclear Generator to Receive ZECs, BPU Docket No. ER20080557 (April 27, 201). *Application of PSEG Nuclear, LLC for the Zero Emission Certificate Program – Salem 2, Order Determining the Eligibility of Salem Unit 2 Nuclear Generator to Receive ZECs*. BPU Docket No. ER20080557 (April 27, 2021).

53 See *New Jersey BPU, In the Matter of the Third Eligibility Period for the Zero Emission Certificate Program Pursuant to N.J.S.A. 48:3-87.3 TO 87.7*, Order Closing the Third Eligibility Period of the Zero Emission Certificate Program, Docket No. EO23080548 (February 14, 2024).

54 CEJA, Public Act 102-0662, 20 ILCS 3855/1-75.

55 See Inflation Reduction Act of 2022, Public Law 117-169 (August 16, 2022).

56 See Inflation Reduction Act of 2022, Public Law 117-169 (August 16, 2022).

met. The Nuclear PTC creates a revenue floor of $40.00/MWh and does not create a revenue ceiling. If nuclear revenues are greater than $43.75/MWh, the Nuclear PTC subsidy does not apply and units keep all profits.

Table 7-25 shows the subsidy received by nuclear units in PJM in $/MWh since 2019.

Table 7-25 Nuclear unit subsidies in $/MWh: 2019 through 2026[57]

	Subsidy ($)							
	2019	2020	2021	2022	2023	2024	2025	2026
Beaver Valley	$0.0	$0.0	$0.0	$0.0	$0.0	$146.4	$0.0	$0.0
Braidwood	$0.0	$0.0	$0.0	$0.0	$0.0	$292.8	$41.1	$0.0
Byron	$0.0	$0.0	$0.0	$0.0	$0.0	$286.8	$36.6	$0.0
Calvert Cliffs	$0.0	$0.0	$0.0	$0.0	$0.0	$52.5	$0.0	$0.0
Cook	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Davis Besse	$0.0	$0.0	$0.0	$0.0	$0.0	$71.3	$0.0	$0.0
Dresden	$0.0	$0.0	$0.0	$0.0	$0.0	$216.6	$29.0	$0.0
Hope Creek	$67.4	$95.6	$97.5	$97.1	$98.3	$118.0	$40.7	$0.0
LaSalle	$0.0	$0.0	$0.0	$0.0	$0.0	$283.8	$36.7	$0.0
Limerick	$0.0	$0.0	$0.0	$0.0	$0.0	$231.3	$0.0	$0.0
North Anna	$0.0	$0.0	$0.0	$0.0	$0.0	$109.2	$0.0	$0.0
Oyster Creek	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Peach Bottom	$0.0	$0.0	$0.0	$0.0	$0.0	$262.6	$0.0	$0.0
Perry	$0.0	$0.0	$0.0	$0.0	$0.0	$92.6	$0.0	$0.0
Quad Cities	$245.3	$244.9	$249.8	$209.2	$79.0	$85.0	$69.6	$17.7
Salem	$131.5	$186.5	$190.2	$189.4	$191.6	$230.5	$66.1	$0.0
Surry	$0.0	$0.0	$0.0	$0.0	$0.0	$113.2	$0.0	$0.0
Susquehanna	$0.0	$0.0	$0.0	$0.0	$0.0	$291.2	$0.0	$0.0
Three Mile Island	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0

Table 7-26 shows the surplus or shortfall in $/MWh for the 16 nuclear plants in PJM, and Oyster Creek and Three Mile Island, calculated using historic LMP and cost data. In 2020, no nuclear plants covered their fuel costs, operating costs, and incremental capital expenditures as a result of lower energy prices. In 2021 and 2022, all nuclear plants more than covered their fuel costs, operating costs, and capital expenditures as a result of higher energy prices. In 2023, only two nuclear plants covered their fuel costs, operating costs, and incremental capital expenditures as a result of lower energy and capacity prices. In 2024, all nuclear plants with the exception of Davis Besse covered their fuel costs, operating costs, and incremental capital expenditures. The surplus or shortfall assumes that the unit receives the DA LMP, reactive capability revenue, cleared its full unforced capacity at the BRA locational clearing price, receives a subsidy if qualified, and has costs equal to the NEI average costs.[58] Unforced capacity is determined using the annual class average EFORd or ELCC rate.[59]

The market revenues are based in part on the sale of capacity. Some nuclear plants did not clear the capacity market in some years as a result of decisions by plant owners about how to offer the plants in the capacity market auctions. When nuclear plants do not clear in the capacity market, it is a result of the offer behavior of the plants and does not accurately reflect the economic viability of the plants. This analysis is intended to define whether the plants are receiving a retirement signal from the PJM markets. If the plants are viable including both energy and capacity market revenues based on actual clearing prices, then the PJM markets indicate that the plant is economically viable. If plant owners decide to offer so as to not clear in the capacity market, that does not change the market signals to the plants. Such decisions may reflect a variety of considerations. Quad Cities and a portion of Byron's capacity did not clear in the 2019/2020 Auction.[60] Quad Cities did not clear in the 2020/2021 Auction.[61] Dresden and most of Byron did not clear in the 2021/2022 Auction.[62] Beaver Valley, Davis Besse, and Perry did not clear in the 2021/2022 Auction.[63] Byron, Dresden, and Quad Cities did not clear in the 2022/2023 Auction.[64]

57 Quad Cities ZECS prices by delivery year are from the Illinois Power Agency final payment calculation notices. Quad Cities subsidies for calendar year 2025 include five months of capacity revenue from the 2024/2025 Delivery Year subsidies and seven months of subsidies revenue for the 2025/2026 Delivery Year.

58 Installed capacity is from NEI. "Maps of U.S. Nuclear Plants," <https://www.nei.org/resources/map-of-us-nuclear-plants>.

59 ELCC rates used starting with the 2025/2026 Delivery Year. See BRA Class Ratings <https://www.pjm.com/planning/resource-adequacy-planning/effective-load-carrying-capability>.

60 Exelon. "Exelon Announces Outcome of 2019-2020 PJM Capacity Auction," (May 25, 2016) <http://www.exeloncorp.com/newsroom/pjm-auction-results-2016>.

61 Exelon, "Exelon Announces Outcome of 2020-2021 PJM Capacity Auction," (May 24, 2017) <http://www.exeloncorp.com/newsroom/pjm-auction-results-release-2017>.

62 Exelon, "Exelon Announces Outcome of 2021-2022 PJM Capacity Auction," (May 24, 2018) <http://www.exeloncorp.com/newsroom/exelon-announces-outcome-of-2021-2022-pjm-capacity-auction>.

63 PRNewswire. "FirstEnergy Solutions Comments on Results of PJM Capacity Auction," (May 24, 2018) <https://www.prnewswire.com/news-releases/firstenergy-solutions-comments-on-results-of-pjm-capacity-auction-300654549.html>.

64 NuclearNewswire. "Byron, Dresden, Quad Cities Fail to Clear in PJM Capacity Auction," (June 8, 2021) <https://www.ans.org/news/article-2967/byron-dresden-quad-cities-fail-to-clear-in-pjm-capacity-auction/>.

Nuclear unit revenue is a combination of energy market revenue, ancillary services market revenue and capacity market revenue. Negative energy market prices do not have a significant impact on nuclear unit revenue. Since 2014, negative energy market prices have affected nuclear plants' annual total revenues by an average of 0.1 percent. Negative LMPs reduced nuclear plant total revenues by an average of 0.0 percent and a maximum of 0.6 percent in 2014, an average of 0.2 percent and a maximum of 1.2 percent in 2015, an average of 0.1 percent and a maximum of 0.7 percent in 2016, an average of 0.0 percent and a maximum of 0.6 percent in 2017, an average of 0.0 percent and a maximum of 0.0 percent in 2018, an average of 0.0 percent and a maximum of 0.2 percent in 2019, an average of 0.1 percent and a maximum of 1.7 percent in 2020, an average of 0.0 percent and a maximum of 0.3 percent in 2021, an average of 0.0 percent and a maximum of 0.0 percent in 2022, an average of 0.0 percent and a maximum of 0.1 percent in 2023, an average of 0.6 percent and a maximum of 4.9 percent in 2024, an average of 0.1 percent and a maximum of 0.8 percent in 2025, and an average of 0.0 percent and a maximum of 0.0 percent in the first three months of 2026.[65]

Table 7-26 shows the surplus or shortfall for the 16 nuclear plants in PJM in $/MWh, including subsidies.

Table 7-26 Nuclear unit surplus (shortfall) based on public data in $/MWh: 2008 through 2025

	ICAP	Surplus (Shortfall) ($/MWh)																	
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Beaver Valley	1,808	$26.3	$6.3	$10.5	$8.8	($3.3)	$1.4	$11.7	$3.2	($0.4)	$2.6	$13.9	$3.7	($2.7)	$15.0	$42.4	$2.1	$12.0	$21.6
Braidwood	2,337	$24.9	$2.5	$6.4	$3.4	($6.1)	($2.6)	$7.2	($1.2)	($3.2)	($1.6)	$5.9	$3.9	($0.0)	$15.1	$35.0	($1.5)	$10.3	$13.9
Byron	2,300	$24.5	($1.3)	$3.4	($0.6)	($9.4)	($3.6)	$4.9	($6.1)	($9.6)	($2.8)	$5.8	$3.2	($0.6)	$14.1	$34.5	($1.9)	$10.6	$13.9
Calvert Cliffs	1,726	$60.6	$20.9	$28.6	$17.9	$4.5	$14.6	$31.6	$14.1	$7.2	$6.1	$16.3	$5.4	($0.9)	$19.4	$54.6	$9.1	$13.5	$32.9
Cook	2,177	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Davis Besse	894	NA	NA	NA	NA	($13.2)	($7.0)	$6.6	($1.2)	($4.0)	($8.4)	($0.9)	($6.3)	($15.1)	$5.9	$31.6	($10.0)	($0.0)	$11.7
Dresden	1,797	$25.6	$3.0	$7.6	$4.4	($5.2)	($1.0)	$9.1	$0.3	($1.6)	($0.1)	$7.1	$4.5	$0.5	$15.7	$36.2	($2.1)	$10.8	$14.0
Hope Creek	1,172	$54.0	$17.0	$24.5	$16.9	$2.6	$12.4	$26.0	$6.3	($1.9)	$1.6	$12.3	$8.8	$7.8	$21.0	$48.0	$6.9	$11.7	$23.0
LaSalle	2,265	$24.8	$2.5	$6.4	$3.3	($6.1)	($1.9)	$7.7	($0.9)	($3.6)	($1.9)	$6.0	$3.7	($0.2)	$14.8	$34.7	($1.8)	$10.0	$13.9
Limerick	2,242	$54.1	$17.1	$24.7	$16.6	$2.6	$12.2	$25.7	$6.5	($2.1)	$1.5	$12.1	$1.6	($2.6)	$11.6	$38.2	($3.3)	$11.2	$18.4
North Anna	1,892	$52.0	$14.6	$25.5	$16.8	$0.2	$5.7	$23.2	$10.9	$3.0	$4.7	$16.0	$4.8	($2.0)	$17.9	NA	NA	NA	$34.5
Oyster Creek	608	$47.5	$8.4	$15.9	$7.2	($8.2)	$3.3	$16.4	($4.7)	($11.6)	($9.9)	NA	NA	NA	NA	NA	NA	NA	NA
Peach Bottom	2,550	$53.7	$16.9	$24.2	$16.1	$2.3	$12.3	$25.5	$5.8	($2.2)	$1.4	$11.9	$0.6	($2.8)	$11.4	$38.3	($3.3)	$11.3	$18.5
Perry	1,240	NA	NA	NA	NA	($13.2)	($6.4)	$5.5	($0.3)	($4.0)	($7.4)	$1.9	($5.9)	($15.2)	$6.2	$32.0	($9.3)	$0.0	$11.3
Quad Cities	1,819	$24.1	($0.4)	$2.4	($1.8)	($13.2)	($6.9)	$0.6	($7.7)	($9.5)	($3.5)	$4.3	$18.8	$14.4	$29.4	$48.7	$3.1	$1.2	$17.3
Salem	2,285	$54.0	$17.1	$24.5	$16.9	$2.6	$12.4	$26.0	$6.2	($2.1)	$1.5	$12.2	$8.5	$7.5	$20.7	$47.6	$6.6	$11.4	$22.7
Surry	1,676	$48.8	$13.8	$24.2	$16.4	($0.0)	$5.1	$21.6	$10.8	$2.6	$4.5	$16.0	$4.2	($2.5)	$17.4	NA	NA	NA	$31.9
Susquehanna	2,494	$46.8	$15.2	$22.4	$16.1	$1.4	$11.1	$24.6	$6.3	($1.6)	$1.8	$10.1	($1.7)	($6.9)	$8.3	$35.9	($2.8)	$10.7	$14.3
Three Mile Island	803	$40.7	$6.5	$13.3	$4.6	($9.6)	$0.9	$13.7	($6.8)	($12.4)	($10.3)	($3.8)	NA	NA	NA	NA	NA	NA	NA

Table 7-27 shows the surplus or shortfall for the 16 nuclear plants in PJM in dollars, including subsidies.

65 Analysis is based on actual unit generation and energy market and capacity market revenues. Negative prices in the DA and RT market were set to zero for comparison. Results round to 0.0 percent.

Table 7-27 Nuclear unit surplus (shortfall) based on public data ($M): 2008 through 2025

	ICAP	Surplus (Shortfall) ($ in millions)																	
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Beaver Valley	1,808	$393.5	$93.3	$156.3	$131.1	($49.4)	$21.0	$174.8	$47.7	($8.9)	$35.7	$204.3	$51.0	($42.5)	$223.0	$632.2	$28.2	$178.2	$321.7
Braidwood	2,337	$482.3	$48.3	$122.8	$65.2	($118.7)	($49.6)	$138.9	($22.7)	($65.2)	($33.3)	$110.8	$70.7	($4.2)	$290.0	$674.9	($32.4)	$197.7	$266.6
Byron	2,300	$465.5	($24.2)	$64.1	($10.5)	($178.9)	($68.6)	$93.2	($116.7)	($185.2)	($55.5)	$106.4	$56.6	($14.8)	$267.5	$654.7	($40.0)	$201.5	$263.3
Calvert Cliffs	1,726	$865.9	$297.3	$406.9	$254.8	$64.5	$208.4	$449.6	$201.4	$100.7	$84.7	$229.8	$74.0	($15.3)	$275.3	$778.7	$128.6	$191.9	$470.9
Cook	2,177	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Davis Besse	894	NA	NA	NA	NA	($98.0)	($51.4)	$48.6	($8.6)	($31.5)	($63.7)	($8.4)	($47.2)	($111.5)	$42.1	$232.3	($76.7)	($1.9)	$85.4
Dresden	1,797	$380.7	$44.6	$112.9	$65.7	($77.7)	($15.0)	$134.6	$4.4	($26.5)	($5.5)	$102.2	$62.2	$4.1	$231.7	$536.2	($34.9)	$159.3	$205.6
Hope Creek	1,172	$523.2	$164.8	$237.0	$163.2	$24.8	$119.9	$251.6	$60.5	($23.2)	$11.2	$114.5	$79.9	$70.3	$200.6	$461.3	$63.3	$109.7	$220.3
LaSalle	2,265	$464.9	$45.9	$119.9	$61.5	($114.1)	($35.3)	$144.7	($16.3)	($69.8)	($37.5)	$109.0	$66.1	($5.6)	$277.3	$648.5	($35.8)	$186.8	$259.2
Limerick	2,242	$1,003.7	$316.3	$457.2	$307.6	$47.8	$226.5	$476.3	$120.1	($41.1)	$25.3	$221.7	$28.2	($48.7)	$213.8	$707.9	($63.4)	$208.5	$341.6
North Anna	1,892	$813.9	$228.5	$397.7	$262.7	$3.5	$89.3	$362.6	$170.2	$44.3	$71.2	$246.5	$71.4	($33.3)	$279.3	NA	NA	NA	$540.6
Oyster Creek	608	$239.0	$42.4	$79.7	$35.9	($41.1)	$16.4	$82.3	($23.4)	($58.2)	($49.6)	NA	NA	NA	NA	NA	NA	NA	NA
Peach Bottom	2,550	$1,133.0	$356.3	$508.8	$338.5	$48.4	$259.6	$537.6	$122.6	($53.0)	$23.7	$242.9	$9.1	($63.3)	$237.2	$805.9	($75.2)	$237.3	$388.4
Perry	1,240	NA	NA	NA	NA	($135.8)	($65.3)	$56.6	($3.5)	($43.2)	($77.5)	$16.9	($61.1)	($155.2)	$62.6	$327.2	($98.4)	($1.1)	$115.1
Quad Cities	1,819	$363.1	($6.7)	$36.3	($27.7)	($199.0)	($103.5)	$8.6	($115.3)	($145.0)	($54.5)	$62.7	$274.3	$207.9	$439.8	$728.9	$42.0	$12.7	$257.4
Salem	2,285	$1,021.3	$322.8	$461.9	$317.9	$48.2	$233.1	$490.0	$117.1	($45.5)	$21.3	$222.5	$155.5	$136.9	$390.3	$898.3	$123.0	$213.8	$415.5
Surry	1,676	$676.9	$190.3	$334.4	$226.4	($0.4)	$71.2	$298.9	$148.8	$33.5	$60.4	$219.1	$53.2	($38.4)	$237.8	NA	NA	NA	$440.6
Susquehanna	2,494	$965.9	$312.8	$461.6	$332.2	$29.4	$229.0	$506.6	$129.9	($39.7)	$31.2	$201.0	($34.4)	($141.3)	$172.0	$742.6	($58.4)	$223.5	$296.6
Three Mile Island	803	$270.5	$42.9	$88.2	$30.2	($63.7)	$5.9	$90.7	($45.2)	($82.3)	($68.1)	($25.3)	NA	NA	NA	NA	NA	NA	NA

In order to evaluate the expected viability of nuclear plants, analysis was based on forward energy market prices for 2026, 2027, and 2028 and known capacity market prices for 2026, 2027, and 2028. The purpose of the forward analysis is to evaluate whether current forward prices are consistent with nuclear plants covering their annual avoidable costs over the next three years. While the forward capacity market prices are known through the 2027/2028 Delivery Year, actual energy prices will vary from forward values. Nuclear plants may choose to sell their output at a range of forward prices and for a range of future years.

Table 7-28 shows PJM energy prices (LMP), annual fuel, and operating and capital expenditures used for the analysis of the period 2026 through 2028. Capacity revenues for calendar year 2026 include five months of capacity revenue from the 2025/2026 Delivery Year and seven months of capacity revenue for the 2026/2027 Delivery Year. Capacity revenues for calendar year 2028 include five months of capacity revenue from the 2027/2028 Delivery Year and seven months of capacity revenue assuming a clearing price of $333.44/MW-Day for the 2028/2029 Delivery Year.[66] The 2028/2029 BRA has not yet been run. The LMPs are based on forward prices with a basis adjustment for the specific plant locations.[67] Forward prices are as of March 31, 2026. The capacity prices are known through May 31, 2028, based on PJM capacity auction results.

66 The price of $333.44/MW-day in unforced capacity was the clearing price for the 2027/2028 Base Residual Auction.
67 Forward prices are reported for PJM trading hubs which are adjusted to reflect the historical differences between prices at the trading hub and prices at the relevant plant locations. The basis adjustment is based on 2025 data.

Table 7-28 Forward prices in PJM energy markets, capacity revenue, and annual costs

	ICAP	Average Forward LMP ($/MWh)			Ancillary Revenue ($/MWh)	Capacity Revenue ($/MWh)			2024 NEI Costs ($/MWh)		
	(MW)	2026	2027	2028	Reactive	2026	2027	2028	Fuel	Operating	Capital
Beaver Valley	1,808	$55.93	$57.48	$56.37	$0.21	$13.24	$14.42	$14.50	$5.27	$18.03	$6.23
Braidwood	2,337	$43.65	$42.57	$41.95	$0.17	$13.24	$14.42	$14.50	$5.27	$18.03	$6.23
Byron	2,300	$46.49	$44.97	$44.28	$0.15	$13.24	$14.42	$14.50	$5.27	$18.03	$6.23
Calvert Cliffs	1,726	$75.78	$66.41	$65.02	$0.19	$13.24	$14.42	$14.50	$5.27	$18.03	$6.23
Cook	2,177	$53.56	$53.62	$52.56	$0.13	NA	NA	NA	$5.27	$18.03	$6.23
Davis Besse	894	$58.69	$57.90	$56.80	$0.21	$13.24	$14.42	$14.50	$5.50	$25.40	$10.72
Dresden	1,797	$47.05	$45.85	$45.17	$0.23	$13.24	$14.42	$14.50	$5.27	$18.03	$6.23
Hope Creek	1,172	$55.86	$53.56	$52.51	$0.47	$13.24	$14.42	$14.50	$5.27	$18.03	$6.23
LaSalle	2,265	$44.25	$43.10	$42.46	$0.13	$13.24	$14.42	$14.50	$5.27	$18.03	$6.23
Limerick	2,242	$55.41	$53.15	$52.10	$0.10	$13.24	$14.42	$14.50	$5.27	$18.03	$6.23
North Anna	1,892	$73.03	$66.39	$65.02	$0.18	$16.38	$14.42	$14.50	$5.27	$18.03	$6.23
Peach Bottom	2,550	$55.47	$53.14	$52.09	$0.31	$13.24	$14.42	$14.50	$5.27	$18.03	$6.23
Perry	1,240	$58.49	$59.40	$58.25	$0.21	$13.24	$14.42	$14.50	$5.50	$25.40	$10.72
Quad Cities	1,819	$47.18	$45.67	$44.95	$0.13	$13.24	$14.42	$14.50	$5.27	$18.03	$6.23
Salem	2,285	$55.81	$53.53	$52.48	$0.35	$13.24	$14.42	$14.50	$5.27	$18.03	$6.23
Surry	1,676	$68.90	$63.23	$61.89	$0.16	$16.38	$14.42	$14.50	$5.27	$18.03	$6.23
Susquehanna	2,494	$49.90	$48.38	$47.37	$0.32	$13.24	$14.42	$14.50	$5.27	$18.03	$6.23

The MMU also calculates the capacity price that would be required to cover the net avoidable costs for each nuclear plant.

Based on the FERC order allowing the inclusion of major maintenance in energy offers, major maintenance costs can no longer be included in gross ACR values offered in the capacity market.[68] The MMU calculates the capacity price that would be required to cover the net avoidable costs for each nuclear plant with major maintenance included in avoidable costs and with major maintenance excluded from avoidable costs. For the case including major maintenance, gross ACR is NEI total cost including fuel, operating cost, and incremental capital expenditures. For the case excluding major maintenance, gross ACR is NEI total cost including fuel and operating cost, excluding capital expenditures as a proxy for fixed VOM, given that NEI does not provide a breakout of major maintenance. NEI incremental capital expenditures are likely to be a conservatively low estimate of major maintenance expense.

All generating plants including nuclear plants must cover their gross avoidable costs, including major maintenance, to remain economically viable. All of the MMU analysis of nuclear plant economics includes gross avoidable costs as reported by NEI unless explicitly stated otherwise.

In Table 7-29, the capacity price required to cover avoidable costs in $/MWh is calculated by taking the total NEI costs in $/MWh and subtracting the total expected energy and ancillary services revenues in $/MWh. Total expected energy revenue is the unit's ICAP multiplied by the average forward LMP multiplied by the class average capacity factor. Total expected ancillary services revenue is unit specific reactive capability revenue.[69] The capacity price required to cover avoidable costs in $/MW-day is calculated by multiplying the required price in $/MWh by 24. Plants may have actual operating costs higher or lower than the NEI average.

In Table 7-29, the capacity price required to cover avoidable costs is $0/MW-day for all units in 2026, 2027 and 2028 using NEI data as reported including capital expenditures, and is $0/MW-day for all plants, excluding capital expenditures as a proxy for major maintenance, in 2026, 2027 and 2028.[70] Net revenues based on forward energy prices alone are greater than or equal to avoidable costs in 2026, 2027 and 2028 without any contribution from capacity market revenues for all plants. The result is that net ACR values for 2026, 2027 and 2028 in Table 7-29 are zero.

68 See 167 FERC ¶ 61,030 at P 41 (2019).

69 Reactive Supply & Voltage Control Revenue Requirements available from PJM <https://www.pjm.com/markets-and-operations/billing-settlements-and-credit.aspx>.

70 PJM's tariff definition of avoidable costs excludes major maintenance. PJM includes major maintenance costs in the definition of short run marginal costs in energy offers.

Table 7-29 Net ACR

	ICAP (MW)	Net ACR ($/MWh) 2026	2027	2028	Net ACR ($/MW-Day) 2026	2027	2028	Net ACR Excluding Capital ($/MW-Day) 2026	2027	2028
Beaver Valley	1,808	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Braidwood	2,337	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Byron	2,300	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Calvert Cliffs	1,726	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Cook	2,177	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Davis Besse	894	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Dresden	1,797	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Hope Creek	1,172	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
LaSalle	2,265	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Limerick	2,242	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
North Anna	1,892	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Peach Bottom	2,550	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Perry	1,240	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Quad Cities	1,819	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Salem	2,285	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Surry	1,676	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Susquehanna	2,494	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Table 7-30 shows the surplus or shortfall that would be received net of avoidable costs and incremental capital expenditures by year, based on forward prices, on a per MWh basis. The fuel and operating costs are the 2024 NEI fuel, operating, and capital costs. Plants may have operating costs higher or lower than the NEI average. Table 7-30 shows the total dollar surplus or shortfall and adjusts energy revenues and operating costs using the annual class average capacity factor.

The 2025 nuclear unit surplus values are shown in Table 7-30 based on forward prices as of March 31, 2026, NEI average costs, and expected subsidy values.[71] The current analysis, based on forward prices for energy, known forward prices for capacity, and an assumed clearing price of $333.44/MW-Day for the 2028/2029 Delivery Year, shows that all PJM nuclear plants analyzed are expected to have a surplus without any subsidy amount in 2026, 2027 and 2028.[72]

Table 7-30 Nuclear unit forward annual surplus (shortfall) for 2026, 2027 and 2028[73 74 75]

	Surplus (Shortfall) ($/MWh) 2026	2027	2028	Subsidy ($/MWh) 2026	2027	2028	Surplus (Shortfall) Excluding Subsidy ($ in millions) 2026	2027	2028	Surplus (Shortfall) Including Subsidy ($ in millions) 2026	2027	2028
Beaver Valley	$39.73	$42.37	$41.34	$0.00	$0.00	$0.00	$510.4	$620.48	$622.62	$510.4	$620.5	$622.6
Braidwood	$27.44	$27.46	$26.91	$0.00	$0.00	$0.00	$420.5	$511.83	$523.10	$420.5	$511.8	$523.1
Byron	$30.27	$29.86	$29.24	$0.00	$0.00	$0.00	$467.9	$549.55	$559.66	$467.9	$549.6	$559.7
Calvert Cliffs	$59.57	$51.30	$49.99	$0.00	$0.00	$0.00	$777.9	$720.79	$719.03	$777.9	$720.8	$719.0
Cook	NA	NA	NA	$0.00	$0.00	$0.00	NA	NA	NA	NA	NA	NA
Davis Besse	$30.40	$30.70	$29.68	$0.00	$0.00	$0.00	$182.9	$219.90	$220.77	$182.9	$219.9	$220.8
Dresden	$30.86	$30.74	$30.13	$0.00	$0.00	$0.00	$374.5	$442.61	$450.58	$374.5	$442.6	$450.6
Hope Creek	$39.77	$38.45	$37.47	$0.00	$0.00	$0.00	$335.6	$363.98	$365.75	$335.6	$364.0	$365.7
LaSalle	$28.02	$27.99	$27.42	$0.00	$0.00	$0.00	$418.4	$505.92	$516.65	$418.4	$505.9	$516.6
Limerick	$39.17	$38.04	$37.06	$0.00	$0.00	$0.00	$630.7	$688.52	$692.00	$630.7	$688.5	$692.0
North Anna	$59.95	$51.28	$49.98	$0.00	$0.00	$0.00	$865.3	$839.23	$788.13	$865.3	$839.2	$788.1
Peach Bottom	$39.31	$38.03	$37.06	$0.00	$0.00	$0.00	$720.4	$782.86	$786.88	$720.4	$782.9	$786.9
Perry	$30.20	$32.20	$31.12	$0.00	$0.00	$0.00	$251.6	$320.46	$321.17	$251.6	$320.5	$321.2
Quad Cities	$30.95	$30.56	$29.92	$1.17	$1.17	$0.00	$380.4	$445.34	$452.81	$398.2	$463.1	$452.8
Salem	$39.67	$38.42	$37.44	$0.00	$0.00	$0.00	$652.4	$709.08	$712.52	$652.4	$709.1	$712.5
Surry	$55.82	$48.12	$46.86	$0.00	$0.00	$0.00	$708.7	$699.18	$654.39	$708.7	$699.2	$654.4
Susquehanna	$33.75	$33.27	$32.34	$0.00	$0.00	$0.00	$587.5	$666.81	$671.32	$587.5	$666.8	$671.3

71 Gross receipts used to calculate the unit subsidy include energy revenue, ancillary services revenue, capacity revenue, and state ZECs subsidies, and assumes the unit meets prevailing wage requirements and receives the Zero Emission Nuclear Power Production Credit 5 times multiplier. Effectively, nuclear power plants will receive the higher of the state or federal subsidy amount.

72 On February 20, 2025, PJM filed with FERC to establish a maximum price of approximately $325/MW-day in unforced capacity and a minimum price of approximately $175/MW-day, both in unforced capacity (UCAP) terms for all capacity auctions for the 2026/2027 and 2027/2028 Delivery Years. See Docket No. ER25-135

73 The state subsidy value for Braidwood, Byron, Dresden, and LaSalle is calculated by taking the applicable Baseline Cost less forward energy prices and known capacity prices.

74 The federal subsidy value for nuclear plants is defined in the Inflation Reduction Act of 2022, Public Law 117-169 (August 16, 2022).

75 North Anna and Surry are in Dominion FRR beginning with the 2022/2023 Delivery Year. North Anna and Surry rejoined the PJM Capacity Market beginning with the 2025/2026 Delivery Year.

8 Environmental and Renewable Energy Regulations

Environmental requirements and renewable energy mandates have a significant impact on PJM markets. State and federal environmental regulatory requirements affect the economic viability of resources. State and federal environmental policies also affect the viability of new resources and the cost of entry. State and federal subsidies for renewable generation have made new solar resources cost competitive with existing coal resources and contributed to the significant level of wind and solar resources entering the market. State and federal subsidies for nuclear generation have increased net revenue for some nuclear plants. Longstanding subsidies for nuclear, coal and oil generation have also significantly affected the economic viability of generation resources using those fuels.

Overview

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.[1] On February 19, 2026, the EPA finalized repeal of the core changes of the 2024 amendments to the rule, including the revised filterable particulate matter (fPM) emission standard, restoring the 0.030 lbs/MMBtu standard that became effective in 2012, and eliminating the requirement to use PM Continuous Emissions Monitoring Systems (CEMS).[2]
- **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.[3] (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.[4] On February 28, 2022, the EPA issued a federal implementation plan for implementation of CSAPR (also known as the Good Neighbor Plan),[5] 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.[6] 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. On January 27, 2026, the EPA proposed approving state implementation plan submissions from eight states, including PJM states Kentucky and Tennessee, for the 2015 ozone NAAQS.[7] Upon becoming final, these states' interstate transport obligations would be resolved without the federal Good Neighbor Plan requirements.
- **NSR/NSPS.** 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.[8] 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.[9]

  New Source Performance Standards (NSPS) set uniform, technology-based emission limits for specific source categories nationwide, pursuant

1 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)

2 See *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units: Final Repeal*, EPA–HQ–OAR–2018–0794; FRL–6716.4–02–OAR, 91 Fed. Reg. 9088 (February 24, 2026).

3 CAA § 110(a)(2)(D)(i)(I).

4 *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).

5 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).

6 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.

7 See *Interstate Transport Plan Review for the 2015 Ozone NAAQS*, EPA–HQ–OAR–2025–0192; FRL–12716–01–OAR, 91 Fed. Reg. 4026 (January 30, 2026).

8 42 U.S.C § 7470 et seq.

9 40 CFR § 52.21.

to Section 111 of the CAA. Numeric emission limits based on the Best System of Emission Reduction (BSER). On January 9, 2026, EPA finalized amendments to NSPS for stationary combustion turbines and stationary gas turbines establishing subcategories for new, modified, or reconstructed stationary combustion turbines based on size, rates of utilization, design efficiency, and fuel type. The EPA determined that combustion controls are BSER for NOX emissions for most new, modified, or reconstructed stationary combustion turbines. For one subcategory, new large turbines with high capacity factors, the BSER for NOX is combustion controls with the addition of selective catalytic reduction (SCR).

- **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.[10] Environmental regulations allow stationary emergency RICE that do not meet the emissions limits and are 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.** The EPA has for years regulated CO_2 as a pollutant using CAA provisions that apply to pollutants not subject to NAAQS.[11] [12] On February 12, 2026, the EPA rescinded the 2009 finding greenhouse gas (GHG) emissions (e.g., CO_2, methane) endanger public health and welfare, removing the legal foundation for EPA GHG regulation.[13] The EPA concluded it lacks statutory authority under CAA Section 202(a) to regulate GHGs for climate change purposes (citing West Virginia v. EPA, Loper Bright, and arguments about "major questions").[14]

- **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.[15]

- **Waters of the United States.** On November 17, 2025, the EPA and the Army Corps of Engineers proposed a rule revising the definition of Waters of the United States in the CWA to fully implement Sackett v. EPA's narrowed requirement that wetlands have a "continuous surface connection" to relatively permanent waters in to be jurisdictional.[16]

- **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.[17] On December 23, 2025, EPA extended the deadlines promulgated in the 2024 rule.[18]

- **Coal Ash.** The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.[19]

10 See 40 CFR § 63.6640(f).
11 See CAA § 111.
12 On April 2, 2007, the U.S. Supreme Court overruled the EPA's determination that it was not authorized to regulate greenhouse gas emissions under the CAA and remanded the matter to the EPA to determine whether greenhouse gases endanger public health and welfare. Massachusetts v. EPA, 549 U.S. 497. On December 7, 2009, the EPA determined that greenhouse gases, including carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride, endanger public health and welfare. See *Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act*, 74 Fed. Reg. 66496, 66497 (Dec. 15, 2009). In a decision dated June 26, 2012, the U.S. Court of Appeals for the D.C. Circuit upheld the endangerment finding, rejecting challenges brought by industry groups and a number of states. Coalition for Responsible Regulation, Inc., et al. v. EPA, No 09-1322.
13 See *Rescission of the Greenhouse Gas Endangerment Finding and Motor Vehicle Greenhouse Gas Emission Standards under the Clean Air Act*, EPA-HQ-OAR-2025-0194; FRL-12715-02- OAR, 91 Fed. Reg. 7686 (February 18, 2026).
14 See *id.* at 7702-7710.
15 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).
16 See Sackett v. EPA, 598 U.S. 651 (2023); *Updated Definition of "Waters of the United States,"* EPA-HQ-OW-2025-0322; FRL 11132.1-01-OW, 90 Fed. Reg. 52498 (November 20, 2025).
17 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).
18 See *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category—Deadline Extensions*, EPA-HQ-OW-2009-0819, 90 Fed. Reg. 61328 (December 31, 2025).
19 42 U.S.C. §§ 6901 *et seq.*

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, Vermont and Virginia (as of July 1, 2026) that applies to power generation facilities. The most recent RGGI auction, held on March 11, 2026, cleared at $24.99 per short ton, or $27.55 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 33.7 percent for a new combustion turbine (CT) unit, $16.85 per MWh or 29.4 percent for a new combined cycle (CC) unit and $43.12 per MWh or 115.1 percent for a new coal plant (CP).

- **Offshore Wind.** New Jersey, Maryland and Virginia have taken significant steps to promote offshore wind. New Jersey and Maryland enacted legislation for offshore wind renewable energy credits (ORECs) in 2010.[20] On January 20, 2025, the Trump Administration issued a Presidential Memorandum withdrawing "from disposition for wind energy leasing all areas within the Offshore Continental Shelf."[21] The withdrawal effectively puts on hold indefinitely the offshore wind projects in New Jersey and Maryland. On May 5, 2025, the Attorneys General of New Jersey and Maryland, along with the 16 other states, filed suit against the withdrawal of offshore leasing.[22]

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, 2026, 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 $14.6 billion over the ten year period from 2014 through 2023, an average annual RPS compliance cost of $1.5 billion. The compliance cost for 2023, the most recent year with almost complete data, was $2.9 billion.[23]

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, 2026, 97.8 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

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

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

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

23 The 2023 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.

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.

Renewable Generation

- **Renewable Generation.** Wind and solar generation was 7.1 percent of total generation in PJM in the first three months of 2026. RPS Tier I generation was 8.4 percent of total generation in PJM and RPS Tier II generation was 1.9 percent of total generation in PJM in the first three months of 2026. Only Tier I generation is defined to be renewable but Tier I 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 2026, Tier I generation from PJM generators met only 48.5 percent of the Tier I RPS requirements.

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.)

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 are not always clear. The price of carbon implied by REC prices ranges from $8.89 per tonne in Ohio to $65.30 per tonne in Virginia. The price of carbon implied by SREC prices ranges from $66.90 per tonne in Pennsylvania to $840.02 per tonne in Washington, DC. The effective prices for carbon compare to the RGGI clearing price in March 2026 of $27.55 per tonne and to the social cost of carbon which is estimated in the range of $50 per tonne.[24] [25] 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.[26] 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.

24 "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>.

25 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>.

26 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 2025 REC and SREC prices in the PJM jurisdictions with RPS. Additional cost impacts are provided in Table 8-9.

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 ten year period from 2014 through 2023 for the ten jurisdictions that had RPS was $1.5 billion, or a total of $14.6 billion over ten years. The RPS compliance cost for 2023, the most recent year for which there is almost complete data, was $2.9 billion.[27] 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 $8.9 billion per year if the carbon price were $24.99 per short ton and emissions levels were five percent below 2025 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 $17.8 billion if the carbon price were $50 per short ton and emission levels were five percent below 2025 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 $24.99 per short ton would be about $6.0 billion. The costs of a carbon price are the impact on energy market prices, net of the revenue returned to states/customers.

Federal Environmental Regulation

The U.S. Environmental Protection Agency (EPA) administers the Clean Air Act (CAA), the Clean Water Act (CWA) and the Resource Conservation and Recovery Act (RCRA), all of which address pollution created by electric power production. The administration of these statutes is relevant to the operation of PJM markets.

The CAA regulates air emissions by providing for the establishment of acceptable levels of emissions of hazardous air pollutants. The EPA issues technology based standards for major sources and area sources of emissions.[28] [29]

The CWA regulates discharges from point sources that affect water quality and temperature.

27 The 2023 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.
28 42 U.S.C. § 7401 et seq. (2000).
29 The EPA defines a "major source" as a stationary source or group of stationary sources that emit or have the potential to emit 10 tons per year or more of a hazardous air pollutant or 25 tons per year or more of a combination of hazardous air pollutants. An "area source" is any stationary source that is not a major source.

The Resource Conservation and Recovery Act (RCRA) regulates the disposal of solid and hazardous waste.[30] Regulation of coal ash or coal combustion residuals affects coal fired power plants.

The EPA's actions have affected and will continue to affect the cost to build and operate generating units in PJM, which in turn affects wholesale energy prices and capacity prices.

CAA: NESHAP/MATS

Section 112 of the CAA requires the EPA to promulgate emissions control standards, known as the National Emission Standards for Hazardous Air Pollutants (NESHAP), from both new and existing area and major sources. On December 21, 2011, the EPA issued its Mercury and Air Toxics Standards rule (MATS), which applies the CAA maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, acid gas, nickel, selenium and cyanide.

The EPA's MATS rule applies the CAA maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide.[31] On February 13, 2023, the EPA issued a final rule reaffirming that it remains appropriate and necessary to regulate hazardous air pollutants (HAP), including mercury, from power plants after considering cost.[32] This action revokes a 2020 finding that it was not appropriate and necessary to regulate coal and oil fired power plants under CAA § 112, and would restore the basis for the MATS rule.

On April 24, 2024, the EPA finalized a strengthened and updated MATS rule reflecting recent developments in control technologies and the performance of coal fired plants.[33] The core proposal revised the (non Hg) fPM emission standard, from 0.030 to 0.010 lbs/MMBtu.[34]

The new administration has taken steps to weaken the enforcement of the MATS rule. In April 2025, in an administrative decision by the EPA under Administrator Lee Zeldin, citing Section 112(i)(4) of the CAA, 47 coal-fired power plants were exempted from MATS compliance for two years. The decision was based on a determination of a need to prolong the life of aging coal plants and support national energy interests. This action is temporary and does not repeal the MATS rule. Repeal of the MATS has been identified as an EPA regulatory goal.[35]

Potentially 16,661 MW of generation in PJM is covered by the two year exemption. Most of the units have either not indicated plans to retire or have repowered, so the impact of the extension alone may not be direct and immediate.

On February 19, 2026, the EPA finalized repeal of the core changes of the 2024 amendments, including the revised filterable particulate matter (fPM) emission standard, restoring the 0.030 lbs/MMBtu standard that became effective in 2012, and eliminating the requirement to use PM Continuous Emissions Monitoring Systems (CEMS).[36]

CAA: NAAQS/CSAPR

The CAA requires each state to attain and maintain compliance with particulate matter (PM) and ozone national ambient air quality standards (NAAQS).[37] Under NAAQS, the EPA establishes emission standards for six air pollutants, including NO_X, SO_2, O_3 at ground level, PM, CO, and Pb, and approves state plans to implement these standards, known as State Implementation Plans (SIPs).

30 42 U.S.C. §§ 6901 *et seq.*

31 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).

32 See *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Revocation of the 2020 Reconsideration, and Affirmation of the Appropriate and Necessary Supplemental Finding*, Final Action, EPA–HQ–OAR–2018–0794, 88 Fed. Reg. 13959 (March 6, 2023).

33 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).

34 *Id.* at 38518.

35 See EPA, EPA Launches Biggest Deregulatory Action in U.S. History (March 12, 2025) ("March 12th EPA Deregulation Notice"), which can be accessed at: <*https://www.epa.gov/newsreleases/epa-launches-biggest-deregulatory-action-us-history*>.

36 See *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units: Final Repeal*, EPA–HQ–OAR–2018–0794; FRL–6716.4–02–OAR, 91 Fed. Reg. 9088 (February 24, 2026).

37 The particulate matter (PM) regulated under the CAA is classified as either PM_{10}, which refers to PM less than 10 microns, and $PM_{2.5}$, which refers PM less than 2.5 microns. $PM_{2.5}$ is referred to as fine particular matter and poses the greatest risk to health. Examples of $PM_{2.5}$ include combustion particles, metals, and organic compounds.

In January 2015, the EPA began implementation of the Cross-State Air Pollution Rule (CSAPR) to address the CAA's requirement that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS. CSAPR requires specific states in the eastern and central United States to reduce power plant emissions of SO_2 and NO_x that cross state lines and contribute to ozone and fine particle pollution in other states. CSPAR requires reductions to levels consistent with the 1997 ozone and fine particle emissions and 2006 fine particle emission NAAQS. CSAPR covers 28 states, including all of the PJM states except Delaware, and also excluding the District of Columbia.

On March 15, 2021, in response to a court holding in *Wisconsin v. EPA*,[38] the EPA finalized decreases to allowable emissions under the Cross-State Air Pollution Rule (CSAPR) and the 2008 ozone NAAQS for 10 PJM states.[39] On February 28, 2022, the EPA proposed a Federal Implementation Plan (FIP) (at that time termed the Transport Rule) for 26 states that addresses the contribution of those states to problems in other states in attaining and maintaining the 2015 Ozone NAAQS.[40] The proposed FIP requirements would establish ozone season NO_x emissions budgets for electric generating units in the PJM states, excluding North Carolina and the District of Columbia.

On March 15, 2023, the EPA finalized Federal Implementation Plan (FIP) requirements for 23 states that addresses the contribution of those states to problems in other states in attaining and maintaining the 2015 Ozone NAAQS.[41] The FIP, also known as the Good Neighbor Plan, resolves the CAA good neighbor obligations of the affected states and applies when no state implementation plan has been approved. The FIP requirements establish ozone season NO_x emissions budgets for electric generating units in the following PJM states: Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, Virginia and West Virginia. The list of PJM jurisdictions excludes North Carolina, the District of Columbia, Tennessee and Delaware. Electric generating units in the indicated states would be required to participate in a revised version of the CSAPR NO_x Ozone Season Group 3 Trading Program that was previously established in the 2021 CSAPR Update.

The EPA's emissions budgets for each PJM state for each ozone season for 2023 through 2029, and beyond are shown in Table 8-1.

Table 8-1 CSAPR NO_x ozone season group 3 state budgets: 2023 through 2029[42]

	Emissions Budget (Tons)							
PJM State	2023	2024	2025	2026	2027	2028	2029	2030+
Illinois	7,474	7,325	7,325	5,889*	5,363*	4,555*	4,050*	*
Indiana	12,440	11,413	11,413	8,410*	8,135*	7,280*	5,808*	*
Kentucky	13,601	12,999	12,472	10,190*	7,908*	7,837*	7,392*	*
Maryland	1,206	1,206	1,206	842*	842*	842*	842*	*
Michigan	10,727	10,275	10,275	6,743*	5,691*	5,691*	4,656*	*
New Jersey	773	773	773	773*	773*	773*	773*	*
Ohio	9,110	7,929	7,929	7929*	7,929*	6,911*	6,409*	*
Pennsylvania	8,138	8,138	8,138	7,512*	7,158*	7,158*	4,828*	*
Virginia	3,143	2,756	2,756	2,565*	2,373*	2,373*	1,951*	*
West Virginia	13,791	11,958	11,958	10,818*	9,678*	9,678*	9,678*	*

*The budget for these years will be subsequently determined and equal the greater of the value above or that derived from the dynamic budget method.

On February 7, 2024, the EPA issued a final rule reducing the primary annual $PM_{2.5}$ standard to 9.0 µg/m³ from 12.0 µg/m³.[43] The rule does not change other $PM_{2.5}$ standards. The proposal responds to the directive in Executive Order 13990 for review of a 2020 Particulate Matter NAAQS Decision that left $PM_{2.5}$ standards unchanged.

On June 27, 2024, the Supreme Court of the United States granted a stay of the FIP and therefore the EPA's enforcement of CSAPR pending judicial review.[44] 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 emissions budgets described in Table 8-1 are not effective. The EPA had previously rejected all proposed state implementation plans for PJM states.

38 Wisconsin v. EPA, 938 F.3d 303, 318–20 (D.C. Cir. 2019).
39 *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).
40 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).
41 See *Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality*, Final Rule, EPA-HQ-OAR-2021-0668.
42 *Id.* at 35 (Table I.B-1).
43 *See Reconsideration of the National Ambient Air Quality Standards for Particulate Matter.* Proposed Rule, Docket No. EPA-HQ-OAR-2015-0072; FRL-8635-01- OAR, 89 Fed. Reg. 16202 (March 6, 2024).
44 Ohio v. EPA, Slip Op. No. 23A349. (S. Ct. June 27, 2024).

The new EPA Administrator has indicated plans to terminate the Good Neighbor Plan and revive negotiation of state implementation plans with the affected states.[45] The Court proceeding reviewing the Good Neighbor Plan is currently in abeyance, and the EPA has informed the D.C. Circuit that it is preparing a proposed rulemaking as part of reconsideration of the Good Neighbor Plan.[46]

On January 27, 2026, the EPA proposed approving state implementation plan submissions from eight states, including PJM states Kentucky and Tennessee, for the 2015 ozone NAAQS.[47] Upon becoming final, these states' interstate transport obligations would be resolved without the federal Good Neighbor Plan requirements.

Figure 8-1 shows average, monthly settled prices for NO_x and SO_2 emissions allowances including CSAPR related allowances for 2020 through 2025. Figure 8-1 also shows the average, monthly settled price for the Regional Greenhouse Gas Initiative (RGGI) CO_2 allowances.

The RGGI CO_2 allowance price averaged $24.72 in the first three months of 2026, a 16.2 percent increase in comparison with the average price in the first three months of 2025. The CSAPR annual NO_x allowance price averaged $3.50 in the first three months of 2026, a 10.8 percent increase in comparison with the average price in the first three months of 2025. The group 2 CSAPR Seasonal NO_x allowance price averaged $892.58 in the first three months of 2026, a 5.7 percent increase in comparison with the average price in the first three months of 2025.[48] The components of real-time LMP analysis shows that NO_x cost contributed $0.17 to the load-weighted average real-time LMP in the first three months of 2025, compared to $0.00 in the first three months of 2025.[49] CO_2 cost (RGGI) contributed $1.83 to the load-weighted average real-time LMP in the first three months of 2026, compared to $1.73 in the first three months of 2025.[50]

45 March 12th EPA Deregulation Notice; Fact Sheet, Good Neighbor Plan (GNP) Powering the Great American Comeback Fact Sheet (March 12, 2025), which can be accessed at: <*https://www.epa.gov/system/files/documents/2025-03/good-neighbor-plan_powering-the-great-american-comeback_fact-sheet.pdf*> .

46 Utah v. EPA, Status Report, D.C. Cir Case No. 23-1157, et al. (November 24, 2025).

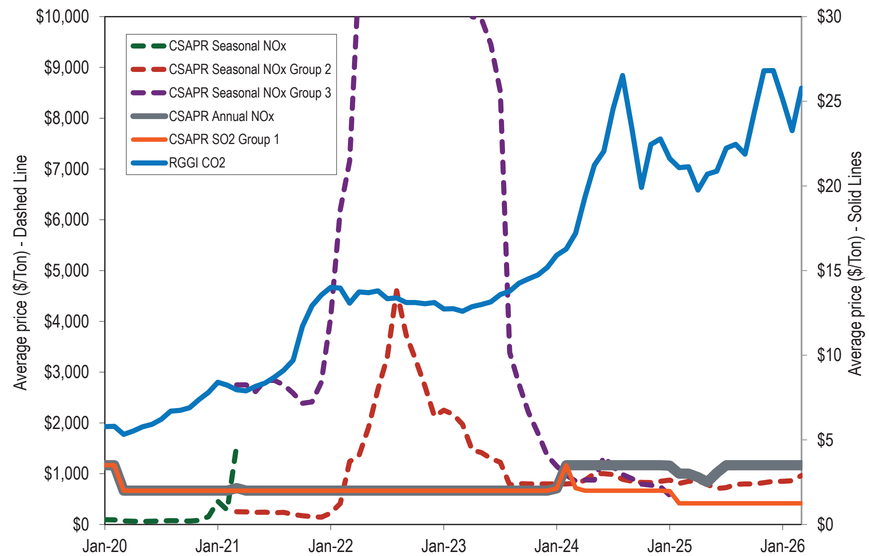
47 See *Interstate Transport Plan Review for the 2015 Ozone NAAQS*, EPA-HQ-OAR-2025-0192; FRL-12716-01-OAR, 91 Fed. Reg. 4026 (January 30, 2026).

48 Tennessee is the only PJM state that remains in the CSAPR NO_x Ozone Season Group 2 Trading Program.

49 See Components of LMP in the *2026 Annual State of the Market Report for PJM January through March*, Section 3: Energy Market.

50 Id.

Figure 8-1 Spot monthly average emission price comparison: 2020 through March 2026[51]



CAA: NSR/NSPS

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.[52] NSR requires permits before construction commences. In PJM, permits are issued by state environmental regulators, or in a process involving state and regional EPA regulators.[53]

51 The CSAPR Seasonal NOx Group 3 price peaked at an average price of $44,826 in March, 2022.

52 42 U.S.C § 7470 et seq.

53 CAA permitting in EPA Region 2 (New Jersey) is the responsibility of the state's environmental regulatory authority; CAA permitting in Region 3 (Delaware, District of Columbia, Maryland, Pennsylvania, Virginia, West Virginia) is the shared responsibility of each state's environmental regulatory authority and EPA Region 3; CAA permitting in Region 4 (Kentucky and North Carolina) is the shared responsibility of each state's environmental regulatory authority and EPA Region 4; CAA permitting in EPA Region 5 (Illinois, Indiana, Michigan and Ohio) is the responsibility of each state's environmental regulatory authority.

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.[54] The first part considers whether a modification would cause a significant emission increase of a regulated NSR pollutant. The second part considers whether any identified increase is also a significant net emission increase.[55]

New Source Performance Standards (NSPS) sets uniform, technology-based emission limits for specific source categories nationwide, pursuant to Section 111 of the CAA. Numeric emission limits based on the Best System of Emission Reduction (BSER) apply to specific listed source categories (e.g., combustion turbines, boilers) that are new, modified, or reconstructed after a certain date.

On January 9, 2026, the EPA finalized amendments to NSPS for stationary combustion turbines and stationary gas turbines establishing subcategories for new, modified, or reconstructed stationary combustion turbines based on size, rates of utilization, design efficiency, and fuel type. The EPA determined that combustion controls are BSER for NOX emissions for most new, modified, or reconstructed stationary combustion turbines. For one subcategory, new large turbines with high capacity factors (e.g. 12 calendar month capacity factors greater than 45 percent), the BSER for NOX is combustion controls with the addition of selective catalytic reduction (SCR).[56]

CAA: RICE

On January 14, 2013, the EPA signed a final rule amending its rules regulating emissions from a wide variety of stationary reciprocating internal combustion engines (RICE). RICE include certain types of electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power, including facilities located behind the meter.[57] These rules include: National Emission Standard for Hazardous Air Pollutants (NESHAP) for Reciprocating Internal Combustion Engines (RICE); New Source Performance Standards (NSPS) of Performance for Stationary Spark Ignition Internal Combustion Engines; and Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (collectively RICE Rules). The RICE Rules apply to emissions such as formaldehyde, acrolein, acetaldehyde, methanol, CO, NO_x, volatile organic compounds (VOCs) and PM.

EPA regulations require that RICE that do not meet the EPA emissions standards (stationary emergency RICE) may operate for only 100 hours per year and only to provide emergency DR during an Energy Emergency Alert 2 (EEA2), or if there are five percent voltage/frequency deviations.[58] Under PJM rules, an EEA2 is automatically triggered when PJM initiates an emergency load response event. Demand resources that rely on RICE to provide load reductions are constrained to a maximum of 100 hours.

Up to 50 hours of the maximum 100 hours can be operated in limited non emergency conditions.[59] By letter issued February 27, 2025, EPA indicated, in response to an inquiry from Duke Energy, that RICE can be operated for up to 50 hours per year to prevent the interruption of power supply in a local area when under an EEA1 and transition to EEA2 is likely without further action.[60]

PJM does not prevent emergency stationary RICE that does not meet emissions standards from participating in PJM markets as DR. Some emergency stationary RICE that does not meet emissions standards are now included in DR portfolios. Some DR registrations reflect a participant's reliance on behind the meter generation having environmental restrictions that limit the resource's ability to operate only in emergency conditions. PJM's DRHUB does not

54 40 CFR § 52.21.

55 *Id.*

56 See *New Source Performance Standards Review for Stationary Combustion Turbines and Stationary Gas Turbines*, EPA–HQ–OAR–2024–0419; FRL–11542–02– OAR, 91 Fed. Reg. 1910 (2026).

57 See *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines*, EPA–HQ–OAR–2008–0708, 78 Fed. Reg. 6674 (January 30, 2013); 40 CFR Parts 60 and 63.

58 Emergency Operations, EOP-011-1, North American Electric Reliability Corporation, <https://www.nerc.com/pa/Stand/Reliability%20 Standards/EOP-011-1.pdf> (Accessed March 2, 2020).

59 See 40 CFR 63.6640(f)(4)(ii) (RICE located at area sources of hazardous air pollutants (HAP)1 can operate for up to 50 hours per year in non-emergency situations to supply power as part of a financial arrangement with another entity). The following conditions must be met: (i) The engine is dispatched by the local balancing authority or local transmission and distribution system operator. (ii) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region. (iii) The dispatch follows reliability, emergency operation or similar protocols that follow specific North American Electric Reliability Corporation (NERC), regional, state, public utility commission or local standards or guidelines. (iv) The power is provided only to the facility itself or to support the local transmission and distribution system. (v) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

60 EPA letter to Duke Energy <*https://www.epa.gov/system/files/documents/2025-05/response-to-duke-energy.pdf*>. The EPA describes Duke's program: "the Mandatory 50 program is deployed when forecasted grid reserves fall below Duke Energy's thresholds for maintaining reliable service—specifically, under Energy Emergency Alert (EEA) Level 1 when transition to EEA Level 2 is imminent without further action. The program would fall below other emergency demand response programs in Duke Energy's resource stack and is constrained to 50 hours per calendar year. The letter states that the program prevents the need for rotating load shed, which would create local disturbances that could result in use of all generators throughout the affected areas."

explicitly identify RICE generators, only whether it is an internal combustion engine. Emergency stationary RICE should be prohibited from participation as DR either when registered individually or as part of a portfolio if it does not meet emissions standards. Emergency RICE with a limit of 100 hours per year cannot comply with the requirement to be available during the entire delivery year to be a capacity resource. PJM should not allow locations that rely upon emergency stationary RICE to register as DR individually or in portfolios. Registration of DR should be based on a finding that registered locations are capable of providing load reductions without an hourly limit. Reliance on the prospect of penalties to deter registration of ineligible resources as DR in lieu of a substantive ex ante review is not appropriate. The MMU recommends that emergency stationary 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.

CAA: Greenhouse Gas Emissions

EPA has for years regulated CO_2 as a pollutant using CAA provisions that apply to pollutants not subject to NAAQS.[61] [62] On February 12, 2026, EPA rescinded the 2009 finding that greenhouse gas (GHG)_emissions (e.g., CO_2 methane) endanger public health and welfare, removing the legal foundation for EPA GHG regulation.[63] EPA concluded it lacks statutory authority under CAA Section 202(a) to regulate GHGs for climate change purposes (citing West Virginia v. EPA, Loper Bright, and arguments about "major questions").[64]

61 See CAA § 111.

62 On April 2, 2007, the U.S. Supreme Court overruled the EPA's determination that it was not authorized to regulate greenhouse gas emissions under the CAA and remanded the matter to the EPA to determine whether greenhouse gases endanger public health and welfare. Massachusetts v. EPA, 549 U.S. 497. On December 7, 2009, the EPA determined that greenhouse gases, including carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride, endanger public health and welfare. See *Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act*, 74 Fed. Reg. 66496, 66497 (Dec. 15, 2009). In a decision dated June 26, 2012, the U.S. Court of Appeals for the D.C. Circuit upheld the endangerment finding, rejecting challenges brought by industry groups and a number of states. Coalition for Responsible Regulation, Inc., et al. v. EPA, No 09-1322.

63 See *Rescission of the Greenhouse Gas Endangerment Finding and Motor Vehicle Greenhouse Gas Emission Standards under the Clean Air Act*, EPA-HQ-OAR-2025-0194; FRL-12715-02- OAR, 91 Fed. Reg. 7686 (February 18, 2026).

64 See *id.* at 7702-7710.

CWA: WOTUS Definition

The Clean Water Act (CWA) applies to navigable waters, which are defined as waters of the United States (WOTUS).[65] [66] The definition of WOTUS is a threshold issue that determines the hydrological scope of the CWA's applicability. Over the past decade, attempts to define WOTUS have been repeatedly addressed by the Courts, and no durable definition has resulted.[67] Establishing a durable definition is important to the electric industry, which needs to plan for compliance with the CWA and related regulations.

The scope of the CWA expanded as a result of an April 23, 2020, decision of the U.S. Supreme Court in *County of Maui v. Hawaii Wildlife Fund*, which held that the discharge of pollutants via groundwater requires a CWA permit.[68] Groundwater is not itself WOTUS. However, if pollutants pass through groundwater from a point source to WOTUS, a permit may be required.[69] The Court held that discharge into groundwater "is the functional equivalent of a direct discharge."[70] The existence of a functional discharge will depend on an analysis including time and distance, and other factors.[71] Additional litigation or administrative action may clarify the functional discharge analysis.[72] *County of Maui* reduces the importance of the precise definition of WOTUS because WOTUS is generally part of the watershed.[73]

On May 25, 2023, a decision of the U.S. Supreme Court held that "jurisdiction over an adjacent wetland under the CWA" requires "first, ... a relatively permanent body of water connected to traditional interstate navigable waters ... and second, that the wetland has a continuous surface connection with

65 33 U.S.C. 1251 et seq.; 33 U.S.C. § 1362(7) ("The term "navigable waters" means the waters of the United States, including the territorial seas.").

66 For more details, see the *2019 Annual State of the Market Report for PJM*, Appendix H: "Environmental and Renewable Energy Regulations."

67 See, e.g., Rapanos v. U.S., 547 U.S. 715 (2006); Solid Waste Agency of Northern Cook County v. U.S. Army Corps of Engineers, 531 U.S. 159 (2001); U.S. v. Riverside Bayview Homes, Inc., 474 U.S. 121 (1985).

68 590 U.S. 165 (April 23, 2020).

69 *Id.*

70 *Id.* at 1.

71 *Id.* at 16 ("The difficulty with this approach, we recognize, is that it does not, on its own, clearly explain how to deal with middle instances. But there are too many potentially relevant factors applicable to factually different cases for this Court now to use more specific language. Consider, for example, just some of the factors that may prove relevant (depending upon the circumstances of a particular case): (1) transit time, (2) distance traveled, (3) the nature of the material through which the pollutant travels, (4) the extent to which the pollutant is diluted or chemically changed as it travels, (5) the amount of pollutant entering the navigable waters relative to the amount of the pollutant that leaves the point source, (6) the manner by or area in which the pollutant enters the navigable waters, (7) the degree to which the pollution (at that point) has maintained its specific identity. Time and distance will be the most important factors in most cases, but not necessarily every case.").

72 *Id.*

73 See *id.* at 5 ("Virtually all water, polluted or not, eventually makes its way to navigable water. This is just as true for groundwater.").

that water, making it difficult to determine where the 'water' ends and the 'wetland' begins."[74] The Court's definition of adjacent wetlands significantly reduced the range of waters meeting that definition compared to the range covered in the 2022 rule.[75]

On March 24, 2025, the EPA and the Army Corps of Engineers issued a memorandum in response to requests for further clarification on the definition of adjacent wetlands, stating: "[A]n interpretation of 'continuous surface connection' which allows for wetlands far removed from and not directly abutting covered waters to be jurisdictional as adjacent wetlands has the potential to violate the direct abutment requirement for 'adjacent wetlands' under the plurality's standard and now *Sackett's* endorsement of that standard.[footnote omitted] Therefore, any components of guidance or training materials that assumed a discrete feature established a continuous surface connection are rescinded."[76]

On November 17, 2025, the EPA and the Army Corps of Engineers proposed a rule revising the definition of WOTUS to fully implement *Sackett v. EPA*'s narrowed requirement that wetlands have a "continuous surface connection" to relatively permanent waters in to be jurisdictional.[77]

CWA: Effluents

The EPA regulates under its National Pollutant Discharge Elimination System (NPDES) permitting authority discharges from and intakes to power plants, including water cooling systems at steam electric power generating stations, under the CWA.[78] The regulations, Effluent Limitations Guidelines and Standards (ELGs), are national industry-specific wastewater regulations based on the performance of demonstrated wastewater treatment technologies.

On June 9, 2022, the EPA proposed the Water Quality Certification Improvement Rule (WQCIR), which would expand the grounds on which states may condition or block, projects in federal permit proceedings.[79] The WQCIR would provide each state certifying agency a role in determining the "reasonable period of time" to review the request and encourage their adoption of an "activity as a whole" analytical approach that would consider the impacts of the entire project rather than just the specific discharge needing certification.[80]

The EPA has been implementing ELGs established in its 2015 and 2020 rules.[81] [82] The 2015 Rule established limitations and standards applicable to discharges from steam electric generating units from bottom ash (BA) transport water, flue gas desulfurization (FGD) wastewater, fly ash (FA) transport water, flue gas mercury control wastewater, gasification wastewater, combustion residual leachate, and non chemical metal cleaning wastes. The 2020 Rule revised the limitations and standards for BA transport water and FGD wastewater, leaving the other limitations and standards in place. The 2020 Rule applied less stringent effluent limits to three new subcategories of units: High FGD flow plants, low utilization generating units, and generating units that will permanently cease the combustion of coal by 2028.

Units subject to the generally applicable limits had to comply with the 2020 Rule as soon as possible on or after October 13, 2021, but no later than December 31, 2025.[83]

Plants are required to inform regulators of their plans to comply with the new rule by upgrading their plants with pollution control equipment or committing to retiring their units by 2028.[84]

Executive Order 13990 called for review and improvement of the 2020 Rule.

On April 25, 2024, pursuant to CWA, the EPA issued a rule strengthening the 2015 and 2020 ELGs for coal-fired power plants ("2024 Effluents Rule").[85] The 2024 Effluents Rule would reduce discharges by an estimated 660–672 million

74 See Sackett v. EPA, 598 U.S. 651 (2023).
75 See *Revised Definition of "Waters of the United States,"* Final Rule, Docket No. EPA-HQ-OW-2021-0602; FRL-6027.4-01-OW, 88 Fed. Reg. 3004 (January 18, 2023).
76 See *WOTUS Notice: The Final Response to SCOTUS; Establishment of a Public Docket; Request for Recommendations*, Docket No. EPA-HQ-OW-2025-0093; FRL-12683-01-OW, 90 Fed. Reg. 13428.
77 See *Updated Definition of "Waters of the United States,"* EPA-HQ-OW-2025-0322; FRL 11132.1-01- OW, 90 Fed. Reg. 52498 (November 20, 2025).
78 See 40 CFR Part 423. For more details, see the *2019 Annual State of the Market Report for PJM*, Appendix H: "Environmental and Renewable Energy Regulations."
79 See *Clean Water Act Section 401 Water Quality Certification Improvement Rule*, Proposed Rule, 87 Fed. Reg. 35318 (June 9, 2022).
80 *Id.* at 35343-35349.
81 See *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, Docket No. EPA-HQ-OW-2009-0819; FRL-9930-48- OW, 80 Fed. Reg. 67838 (November 3, 2015).
82 See *Steam Electric Reconsideration Rule*, Docket No. EPA-HQ-OW-2009-0819; FRL-10014-41-OW, 85 Fed. Reg. 64650 (October 13, 2020).
83 *Id.* at 64652.
84 85 Fed. Reg. 64650, 64679-82; 88 Fed. Reg. 18440 (March 29, 2023); 40 CFR § 423.19(f)(1).
85 See *Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, EPA Docket No. EPA-HQ-OW-2009-0819; FRL-8794-01- OW, Final Rule, 89 Fed. Reg. 40198 (May 9, 2024) ("2024 Effluents Rule"); CWA §§ 301, 304, 306, 307, 308, 402 & 501.

pounds per year, including toxic and bio accumulative pollutants, such as arsenic, lead, mercury, selenium, chromium, and cadmium.[86]

This 2024 Effluents Rule establishes a zero discharge of pollutants limitation for three wastewaters generated at coal-fired power plants: flue gas desulfurization wastewater, bottom ash transport water, and combustion residual leachate.[87] The regulation also establishes numeric discharge limitations for mercury and arsenic for combustion residual leachate (CRL) that is discharged through groundwater and for a fourth waste stream, called legacy wastewater, that is discharged from certain surface impoundments.[88] The regulation also eliminates less stringent requirements for two subcategories of facilities (high flow facilities and low utilization energy generating units) that were contained in the 2020 regulation.[89]

The 2024 Effluents Rule allows additional time for compliance for some plants that have installed, or are in the process of installing, additional treatment technologies to meet the 2015 and 2020 ELGs.[90] The rule allows some plants to continue to meet the 2015 and 2020 ELGs while they are in the process of closing and converting to use other fuels such as natural gas.[91] On December 23, 2025, the EPA finalized a rule extending the deadlines promulgated in the 2024 Effluents Rules, updating the rule's transfer provisions to allow facilities to switch between compliance alternatives, and creating authority for alternative applicability dates and paperwork submission dates, based on site-specific factors.[92] The rule extends implementation dates by: (i) providing six more years (to December 31, 2031) for existing steam electric power plants to assess potential compliance pathways for their continued operations; (ii) extending compliance deadlines by five years (to December 31, 2034) related to zero-discharge limitations for flue gas desulfurization wastewater, bottom ash transport water, and combustion residual leachate; and (iii) providing more time for compliance with three zero-discharge limitations for power plants that send wastewater to wastewater treatment plants for processing. The agency's proposal would align these deadlines with the deadlines for power plants that discharge directly to waterways.

RCRA: Coal Ash

The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.[93] Solid waste is regulated under subtitle D. Subtitle D criteria are not directly enforced by the EPA. Subtitle C governs the disposal of hazardous waste. Hazardous waste is subject to direct regulatory control by the EPA from the time it is generated until its ultimate disposal.

On April 17 2015, the EPA published a rule under Subtitle D of RCRA, the Coal Combustion Residuals rule (2015 CCRR), which sets criteria for the disposal of coal combustion residues (CCRs), or coal ash, produced by electric utilities and independent power producers.[94] CCRs include fly ash (trapped by air filters), bottom ash (scooped out of boilers) and scrubber sludge (filtered using wet limestone scrubbers). These residues are typically stored on site in ponds (surface impoundments) or sent to landfills.

In 2016, RCRA was amended to establish a permitting scheme allowing states to apply to the EPA for approval to operate a permit program that implements the CCR rule. Such state programs could include alternative state standards, provided that the EPA determines that they are ''at least as protective as'' the EPA CCR regulations.[95]

Effective August 9, 2018, the EPA approved certain revisions to the 2015 CCRR ("2018 CCRR Revisions") partly in response to the 2016 amendments.[96]

The 2018 CCRR Revisions provide for two types of alternative performance standards. The first type of standards allows a state director (if a state has an EPA approved CCR permit program) or the EPA (if no state program) to suspend groundwater monitoring requirements if there is evidence that there is no potential for migration of hazardous constituents to the uppermost

86 *Id.* at 40198, 40203.
87 *Id.* at 40198.
88 *Id.* at 40252.
89 *Id.* at 40200.
90 *Id.*
91 *Id.* at 40246.
92 See *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category—Deadline Extensions*, EPA-HQ-OW-2009-0819, 90 Fed. Reg. 61328 (December 31, 2025).
93 42 U.S.C. §§ 6901 *et seq.*
94 *See Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals from Electric Utilities*, 80 Fed. Reg. 21302 (April 17, 2015).
95 The Water Infrastructure Improvements for the Nation Act (WIIN Act).
96 See *Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals from Electric Utilities; Amendments to the National Minimum Criteria (Phase One, Part One)*, EPA Docket No. EPA-HQ-OLEM-2017-0286, 83 Fed. Reg. 36435 (July 30, 2018).

aquifer during the active life of the unit and during post closure care. The second type allows issuance of technical certifications by a state director in lieu of a professional engineer.

The 2018 CCRR Revisions revised the groundwater protection standards for health-based levels for four contaminants: cobalt at 6 mg/L; lithium at 40 mg/L; molybdenum at 100 mg/L and lead at 15 mg/L. Standards for other monitored contaminants follow the Maximum Contaminant Level (MCL) established under the Safe Water Drinking Act.

The 2018 CCRR Revisions extended the deadline for closing coal ash units in two situations: (i) detection of a statistically significant increase above a groundwater protection standard from an unlined surface impoundment; or (ii) inability to comply with the location restriction regarding placement above the uppermost aquifer. The exceptions in the 2018 CCRR to the standards in the 2015 CCRR and relaxation of the deadlines create a less stringent federal rule.

The U.S. Court of Appeals for the D.C. Circuit invalidated certain provisions of the 2015 CCRR and remanded it to the EPA.[97]

On July 29, 2020, the EPA finalized revisions to the CCR rule in compliance with the court orders ("Revised CCRR").[98] The Revised CCRR requires (i) unlined surface impoundments (ponds) and ponds failing restrictions on the minimum depth to or interaction with an aquifer to cease receiving waste as soon as technically feasible and no later than April 11, 2021; and (ii) removal of compacted soil lined and clay lined ponds from classification as lined and exempt from CCRR.[99]

In response to the RCRA amendments, the EPA proposed a new rule to implement a federal CCR permit program in nonparticipating states, noticed February 20, 2020.[100] This proposal includes requirements for federal CCR permit applications, content and modification, as well as procedural requirements. The EPA would implement this permit program at CCR units located in states that have not submitted their own CCR permit program for approval. No PJM state has yet applied for EPA approval of its own CCR permit program.

The new EPA Administrator has indicated plans to prioritize expeditious state permit reviews and update the CCR permit program.[101]

State Environmental Regulation

State Coal Ash Regulations

In Virginia, the Waste Management Board amended the Virginia Solid Waste Management Regulations in December 2015, to incorporate the EPA's 2015 CCRR, and did not adopt the less stringent 2018 CCRR Revisions. On July 1, 2019, Virginia enacted legislation directing the closure of coal ash ponds located in the Chesapeake Bay Watershed and owned by Dominion Energy.[102] Dominion is developing plans to remove coal ash ponds at power stations in the Chesapeake Bay Watershed. The removed coal ash must be recycled (at least 6.8 million cubic yards) or disposed of in a modern, lined landfill. The Virginia DEQ is addressing closing ash ponds under two types of environmental permits: wastewater discharge permits covering the removal of treated water from the ponds; or solid waste permits covering the permanent closure of the ponds.

97 Utility Solid Waste Activities Group, et al. v. EPA, 901 F.3d 414 (D.C. Cir. August 21, 2018); Waterkeeper Alliance Inc. et al. v. EPA, No. 18-1289 (D.C. Cir. March 13, 2019).
98 See *Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals from Electric Utilities; A Holistic Approach to Closure Part A: Deadline to Initiate Closure*, EPA-HQ-OLEM-2019-0172; FRL-10002- 02-OLEM, 85 Fed. Reg. 53516 (August 28, 2020).
99 *Id.* at 53516-53517, 53536.
100 *See Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals from Electric Utilities; Federal CCR Permit Program*, EPA-HQ-OLEM-2019-0361, 85 Fed. Reg. 9940 (February 20, 2020).
101 March 12th EPA Deregulation Notice.
102 Va. Code § 10.1-1402.03.

Table 8-2 shows the compliance status of affected units with Virginia Solid Waste Management Regulations:[103]

Table 8-2 Compliance status of affected units with Virginia Solid Waste Management Regulations

Plant	CCR Compliance Status
Bremo Bluff Power Station	As of April 2020, ash has been removed from the East and West Ponds. Plans for closure by removal of ash from the remaining North Pond impoundment are under development and will be addressed by the Virginia DEQ in a separate future permitting action.
Chesapeake Energy Center	The facility filed a proposed modification of its permit in March 2025 for removal of ash from the landfill, historical area, and impoundment.
Chesterfield Power Station	Dominion Energy Virginia submitted the required solid waste permit application for closure by removal and groundwater monitoring of the Upper and Lower Ash Ponds in February 2020, and it is currently under review. The application outlines the removal of ash to either an offsite permitted landfill or offsite beneficial reuse. The application estimates that it will take approximately 13 years to complete closure by removal activities.
Clinch River Power Station	The ash pond was closed and capped prior to January 1, 2019. Clinch River Plant ceased burning coal in 2015 and no longer produces CCR material. The Plant now uses natural gas as fuel. All units are currently being monitored and maintained in post-closure care.
Clover Power Station	The station also has had a permitted CCR landfill since 1993. The permit has been modified to incorporate EPA CCR Rule requirements applicable to existing landfills.
Possum Point	The impoundments at this facility (coal ash ponds) are subject to the EPA CCR Rule and the requirements of Virginia Waste Management Act.

Effective April 21, 2021, in response to a statutory mandate,[104] the Illinois Environmental Protection Agency (Illinois EPA) promulgated rules for coal combustion residual surface impoundments with the Illinois Pollution Control Board.[105] The proposed rules contain standards for the storage and disposal of coal combustion residuals in surface impoundments. The rules include a permitting program intended to meet federal standards.[106] The Illinois EPA identified 73 coal combustion residuals surface impoundments at power stations, some lined with impermeable materials and some not.[107] The Illinois EPA believes that as many as six lined surface impoundments may comply with the federal liner standards.[108]

State Emissions Regulations

States have in some cases enacted emissions regulations more stringent or potentially more stringent than federal requirements:[109]

- **Illinois Climate and Equitable Jobs Act (CEJA).** On September 16, 2021, the Climate and Equitable Jobs Act (CEJA) became law. CEJA created an expanded nuclear subsidy program. CEJA mandates 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. The emissions caps are based on average emissions over a three year period from 2018 through 2020. The capped emissions are CO_2e and co-pollutants.[110] [111] New investor owned, gas fired units will have emissions caps after three years of operation. The resultant emissions caps are very low for some units and higher for others. More than 10,000 MW of capacity are currently affected, most of which have requested that the MMU calculate a unit specific opportunity cost. The MMU calculates opportunity costs for units that make requests and provide required data.

  CEJA includes provisions promoting the development of batteries and utility scale solar at the sites of up to five closed coal plants, two of which may be located in PJM. CEJA grants a subsidy of $110,000/MW for battery projects with at least 37 MW of capacity, capped at $28 million per year. A solar resource at a defined site may elect to receive either the battery subsidies or to sell premium RECs for $30 each.

- **New Jersey HEDD.** Units that run only during peak demand periods have relatively low annual emissions, and have less reason to make investments in emissions reductions under the EPA transport rules. New Jersey addressed the issue of NO_x emissions on peak energy demand days with

103 Virginia Department of Environmental Quality website: <*https://www.deq.virginia.gov/permits/waste/coal-ash*>.
104 Ill. Public Act 101-171 (a.k.a. SB 09).
105 The proposed rule amends the Illinois Administrative Code to create a new Part 845 in Title 35.
106 See *In the Matter of Standards for the Disposal of Coal Combustion Residuals in Surface Impoundments*, No. R 2020-019 (March 30, 2020) at 1 (Proposed New 35 Ill. Adm. Code 845).
107 In the Matter of Standards for the Disposal of Coal Combustion Residuals in Surface Impoundments, No. R 2020-019 (March 30, 2020) at 3 (Proposed New 35 Ill. Adm. Code 845z0.
108 *Id.*
109 For more details, see the *2019 State of the Market Report for PJM*, Appendix H: "Environmental and Renewable Energy Regulations."
110 Carbon dioxide equivalent (CO2e) emissions means the total emissions of six greenhouse gases (carbon dioxide, nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride). Co-pollutants mean the six criteria pollutants identified by the US EPA pursuant to the Clean Air Act: Carbon Monoxide, Lead, Nitrogen Dioxide, Ozone, Particle Pollution, and Sulfur Dioxide.
111 See Energy Transition Act, Public Act 102-0662, Section 90-55, which amends section 9.15 (k-5) FOR the Illinois Environmental Protection Act.

a rule that defines peak energy usage days, referred to as high electric demand days or HEDD, and imposes operational restrictions and emissions control requirements on units responsible for significant NO_X emissions on such high energy demand days. New Jersey's HEDD rule, which became effective May 19, 2009, applies to HEDD units, which include units that have a NO_X emissions rate on HEDD equal to or exceeding 0.15 lbs/MMBtu and lack identified emission control technologies.

- **New Jersey Control and Prohibition of Carbon Dioxide Emissions.** On December 2, 2022, New Jersey implemented rules restricting new power plants to CO_2 emissions less than 860 pounds per megawatt hour, and banning sales of No. 4 and No. 6 fuel oil.[112] The rule limits existing electric generating units to no more than 1,700 lbs of CO_2 per megawatt hour of the gross energy input, by January 1, 2024, to no more than 1,300 pounds per megawatt hour by 2027, and to no more than 1,000 pounds per megawatt hour by 2035.
- **Climate Solutions Now Act of 2022.** One April 8, 2022, Maryland enacted a requirement for reduction of statewide greenhouse gas emissions by 60 percent from 2006 levels by 2031 and net-zero emissions by 2045.[113]
- **Illinois Air Quality Standards (NO_X, SO_2 and Hg).** The State of Illinois has promulgated its own standards for NO_X, SO_2 and Hg (mercury) known as Multi-Pollutant Standards (MPS) and Combined Pollutants Standards (CPS). MPS and CPS establish standards that are more stringent and take effect earlier than comparable Federal regulations, such as the EPA's MATS.

Some states proposed legislation in 2024 designed to reduce or eliminate greenhouse gas and other emissions. The proposed legislation is summarized in Table 8-3.

112 See N.J.A.C. 7:27F.

113 See Maryland SB 528.

Table 8-3 Summary of proposed environmental regulatory activity affecting PJM resources by jurisdiction

Jurisdiction	Bill/Docket No.	Environmental Regulatory Activity
Delaware	SB 205	153rd Gen. Assembly: Would require any entity seeking to begin the business of using 30 MW of electricity or greater to first obtain a Certificate to Operate (COP) from the PSC.
	HB 233	153rd Gen. Assembly: Act requires regulated utilities to establish a separate rate for data centers to avoid cost shifts to other customers.
	HCR 94	153rd Gen. Assembly: Resolution urging PJM to maintain price collars at the current rate and encouraging reforms to the interconnection queue.
Illinois	HB 3758/SB 2497	104th General Assembly: Bill requiring energy storage procurement and reforms to the grid interconnection process.
Indiana	HB 1434	2026 Reg. Sess.: Requires utilities to report votes at RTO stakeholder meetings.
	HB 1245	2026 Reg. Sess.: Requires the IURC to conduct a study to evaluate the effect of new and additional electricity demand from data centers on: (1) the costs incurred by energy utilities to meet that demand; and (2) retail electric rates for all customer classes of energy utilities.
Kentucky	HB 593	2026 Reg. Sess.: Requires utilities to file tariff for service to data centers that protect customers rates and reliability.
Maryland	SB 596	2026 Reg. Sess.: Exempts certain large load customers from requirements to obtain a CPCN; requires the PSC to establish a certain process for large load customers to interconnect to the electric system; establishes requirements for a large load customer to interconnect to the electric system and contract for service; and authorizes certain large load customers to receive certain prioritization.
	SB 801	2026 Reg. Sess.: Requires the Governor to withdraw the State from RGGI by January 1, 2027; authorizing the State to rejoin on certain conditions.
Michigan		No current activity.
New Jersey	A 2938/S 2462	2026-2027 Reg. Sess.: "Grid Reliability Protection Act" prohibits State agencies from decommissioning electric generation facilities under certain circumstances.
	A 4710	2026-2027: "Clean Energy AI Incentivization Act" directs BPU to incentivize artificial intelligence centers to bring their own self-sufficient, clean energy.
	S 4062/A 4801	2026-2027 Reg. Sess.: Establishes certain protections against demand by large-load addition customers in State.
	A 796	2026-2027 Reg. Sess.: Requires electric public utilities to develop and apply special rules for certain data centers to protect non-data center customers from increased costs.
North Carolina		No current activity.
Ohio	SB 381	136th Gen. Assembly: Requires PUCO approval to connect data centers to electrical grid.
Pennsylvania	HB 782	2025-2026 Reg. Sess.: Requires public utilities to report lobbying and political activities expenses to exclude them from rates; requires electric distribution companies to be in an RTO and to report voting in PJM processes.
	SB 1068	2025-2026 Reg. Sess.: An Act providing for the abrogation of regulations relating to the CO2 Budget Trading Program.
	HR 361	2025-2026 Reg. Sess.: Directs the Joint State Government Commission to study the costs and benefits of Pennsylvania's continued membership in PJM, including potential alternatives for grid management, reliability, and affordability amid rising prices and demand.
	SR 188	2025-2026 Reg. Sess.: Directs the Joint State Government Commission to study the costs and benefits of continued membership in PJM, with specific reference to the upcoming December 2025 capacity auction for 2027-2028 and broader reliability/price issues.
	HB 1834	2025-2026 Reg. Sess.: Provides for PUC regulation of commercial data centers, including impacts on the PJM grid (e.g., requiring assessments of effects on PJM's regional transmission system from large loads).
	SB 991	2025-2026 Reg. Sess.: Streamlines permitting for data centers (often at former power sites) to accelerate development amid PJM demand pressure.
Tennessee	HB 1847/SB 2128	114th Gen. Assembly: Requires the owner/operator of a data center to pay for and the electric utility to ensure that the owner/operator pays for full cost of infrastructure needed to support the data center.
	SB 2681	114th Gen. Assembly: "BYOG" Act requires that new data centers with estimated peak load above100 MW must derive 50% of their electricity supply from new, carbon-free energy sources located onsite or through direct interconnection.
Virginia	SB 619	2026 Reg. Sess.: Prohibits any person from operating a high-load facility (demand exceeds 90 MW) not operational before January 1, 2027, without a CPCN.
Washington, D.C.		No current activity.
West Virginia	HB 5657	2026 Reg. Sess.: The Electric Choice and Competition Act permits retail competition for the purchase and sale of electric power for certain non-residential retail customers.

Clean Energy Standards

- In April 2020, Virginia enacted the Virginia Clean Economy Act, which orders the closure of most coal generation in state by 2024, most fossil fuel generation by 2045, and adopts a 100 percent clean energy standard by 2045.[114] The legislation mandates Chesterfield Power Station Units 5 & 6 and Yorktown Power Station Unit 3 to be retired by the end of 2024, Altavista, Southampton and Hopewell to be retired by the end of 2028 and Virginia Power's remaining

114 Va. HB 1526/SB 851.

fossil fuel units to be retired by the end of 2045, unless the retirement of such generating units will compromise grid reliability or security.[115] The legislation also imposes a temporary moratorium on Certificates of Public Convenience and Necessity for fossil fuel generation, unless the resources are needed for grid reliability.[116]

Opportunity Cost

- PJM generators are subject to environmental constraints that limit generation. These constraints are specified in the operating permits issued by the jurisdictional environmental authority. Schedule 2 of the PJM Operating Agreement provides that the opportunity cost associated with the environmental constraints may be included in a generator's cost-based offer.[117] Opportunity cost associated with a physical equipment limitation or a fuel supply limitation, under certain circumstances, may also qualify for inclusion in the cost-based offer.[118]
- More than 10,000 MW of capacity are currently affected by CEJA, most of which have requested that the MMU calculate a unit specific opportunity cost. The CEJA operating limits have resulted in significant opportunity cost adders to cost-based energy market offers for affected units.
- The MMU calculates opportunity costs for units that make requests and provide the required data. The MMU calculated opportunity cost adders for 168 generators in the first three months of 2026. The calculations are generally done one time per week and the resulting opportunity cost is effective for a seven day period. More frequent calculations are done in cases where the constraints are tight and the opportunity cost is expected to vary significantly from day to day.

RGGI

The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey (as of January 1, 2020), New York, Rhode Island, Vermont and Virginia (2021–2023, and effective July 1, 2026) to cap CO_2 emissions from power generation facilities.[119] Virginia withdrew from RGGI effective January 1, 2024 and rejoined effective July 1, 2026.

Delaware, Maryland and New Jersey are members of RGGI, and Virginia was a member from January 1, 2021 through 2023. New Jersey, a founding member of RGGI, opted out in 2011 but rejoined RGGI in 2020.[120] Virginia joined RGGI on January 1, 2021, and left RGGI on December 31, 2023. A decision issued November 18, 2024, by the Floyd County Circuit Court of Virginia determined that the Governor lacked the authority to remove Virginia from RGGI.[121] Virginia is rejoining RGGI effective July 1, 2026. Pennsylvania took action to join RGGI on April 23, 2022, but such action was enjoined by court order on appeal.[122] [123] After Pennsylvania legislation explicitly removed the RGGI regulation from the Pennsylvania Code in November 12, 2025, the Pennsylvania Supreme Court dismissed the appeal as moot without a decision on the merits.[124] [125]

Table 8-4 shows the RGGI CO_2 auction clearing prices and quantities, in short tons and metric tonnes, for the 3rd control period through the 6th control period.[126] The clearing price for the auction held March 11, 2026, was $24.99 per allowance (equal to one short ton of CO_2).[127] The March auction cleared above the 2026 Cost Containment Reserve (CCR) trigger price of $18.22, exhausting the CCR reserve for 2026.[128] All RGGI auctions held since March

115 See Dominion Energy, Inc., et al., SEC Form 10-Q (Quarter ending June 30, 2020).
116 *Id.*
117 PJM Operating Agreement, Schedule 2,
118 Id. at 5(b).

119 RGGI provides a link on its website to state statutes and regulations authorizing its activities, which can be accessed at: <*http://www.rggi.org/design/regulations*>.
120 "Statement on New Jersey Greenhouse Gas Rule," RGGI Inc. (June 17, 2019) <*https://www.rggi.org/sites/default/files/Uploads/Press-Releases/2019_06_17_NJ_Announcement_Release.pdf*>.
121 See Association of Energy Conservation Professionals v. Virginia State Air Pollution Control Board, Case No. CL23000173-00.
122 CO2 Budget Trading Program, 52 Pa.B. 2471 (April 23, 2022), codified 25 Pa. Code Ch. 145; *see also* Executive Order–2019-07. Commonwealth Leadership in Addressing Climate Change through Electric Sector Emissions Reductions, Tom Wolf, Governor, October 3, 2019, <https://www.governor.pa.gov/newsroom/executive-order-2019-07-commonwealth-leadership-in-addressing-climate-change-through-electric-sector-emissions-reductions/> .
123 See *Bowfin KeyCon Holdings, LLC v. Pennsylvania Department of Environmental Protection*, 347 M.D. 2022 (November 1, 2023) ("held that the Pennsylvania [DEP]'s CO2 Budget Trading Program Regulation is an unconstitutional tax, declared the rule to be void, and enjoined DEP from enforcing it"); *Ramez Ziadeh, et al. v. Pennsylvania Legislative Reference Bureau*, Memorandum Opinion, Commonwealth Court of Pennsylvania Case No. No. 41 M.D. 2022 (July 8, 2022); *Ramez Ziadeh, et al. v. Pennsylvania Legislative Reference* Bureau, Order Granting Application to Vacate, Commonwealth Court of Pennsylvania Case No. No. 41 M.D. 2022 (July 25, 2022).
124 See Pennsylvania Act 45 of 2025, HB 416.
125 See *Shirley v. Pennsylvania Legislative Reference Bureau* (No. 247 M.D. 2022); Supreme Court Docket Nos. 81 MAP 2022, 83 MAP 2022, or 85 MAP 2022 (January 6, 2026).
126 Each control period is three years in duration. The 3rd control period covers 2015 through 2017. The 4th control period covers 2018 through 2020. The 5th control period covers 2021 through 2023. The 6th control period covers 2024 through 2026.
127 RGGI measures carbon in short tons (short ton equals 2,000 pounds) while world carbon markets measure carbon in metric tonnes (metric tonne equals 1,000 kilograms or 2,204.6 pounds).
128 RGGI auctions employ a price cap called the Cost Containment Reserve (CCR) trigger price. When demand for allowances exceeds the supply at the CCR trigger price, the auction is cleared by setting the price equal to the CCR trigger price and drawing on allowances that are held in reserve. In the March 2026 auction, the reserve allowances were not sufficient to meet the demand at the CCR trigger price and the auction cleared above the CCR trigger price. Since the CCR allowances for 2026 have been exhausted, the CCR trigger price of $18.22 will not affect the remaining RGGI auctions in 2026.

2024 have cleared above the CCR trigger price. The March 2026 auction clearing price decreased 6.5 percent from the last auction clearing price of $26.73 in December 2025. The auction clearing price in March 2026 was 26.5 percent higher than the auction clearing price in March 2025.

Table 8-4 RGGI CO_2 allowance auction prices and quantities in short tons and metric tonnes: 3rd, 4th, 5th and 6th Control Periods[129]

	Short Tons				Metric Tonnes			
Auction Date	Clearing Price	Quantity Offered	Cost Containment Reserve	Quantity Sold	Clearing Price	Quantity Offered	Cost Containment Reserve	Quantity Sold
March 11, 2015	$5.41	15,272,670		15,272,670	$5.96	13,855,137		13,855,137
June 3, 2015	$5.50	15,507,571		15,507,571	$6.06	14,068,236		14,068,236
September 9, 2015	$6.02	15,374,294	10,000,000	25,374,294	$6.64	13,947,329	9,071,850	23,019,179
December 2, 2015	$7.50	15,374,274		15,374,274	$8.27	13,947,311		13,947,311
March 9, 2016	$5.25	14,838,732		14,838,732	$5.79	13,461,475		13,461,475
June 1, 2016	$4.53	15,089,652		15,089,652	$4.99	13,689,106		13,689,106
September 7, 2016	$4.54	14,911,315		14,911,315	$5.00	13,527,321		13,527,321
December 7, 2016	$3.55	14,791,315		14,791,315	$3.91	13,418,459		13,418,459
March 8, 2017	$3.00	14,371,300		14,371,300	$3.31	13,037,428		13,037,428
June 7, 2017	$2.53	14,597,470		14,597,470	$2.79	13,242,606		13,242,606
September 8, 2017	$4.35	14,371,585		14,371,585	$4.80	13,037,686		13,037,686
December 8, 2017	$3.80	14,687,989		14,687,989	$4.19	13,324,723		13,324,723
March 14, 2018	$3.79	13,553,767		13,553,767	$4.18	12,295,774		12,295,774
June 13, 2018	$4.02	13,771,025		13,771,025	$4.43	12,492,867		12,492,867
September 9, 2018	$4.50	13,590,107		13,590,107	$4.96	12,328,741		12,328,741
December 5, 2018	$5.35	13,360,649		13,360,649	$5.90	12,120,580		12,120,580
March 13, 2019	$5.27	12,883,436		12,883,436	$5.81	11,687,660		11,687,660
June 5, 2019	$5.62	13,221,453		13,221,453	$6.19	11,994,304		11,994,304
September 4, 2019	$5.20	13,116,447		13,116,447	$5.73	11,899,044		11,899,044
December 4, 2019	$5.61	13,116,444		13,116,444	$6.18	11,899,041		11,899,041
March 11, 2020	$5.65	16,208,347		16,208,347	$6.23	14,703,969		14,703,969
June 3, 2020	$5.75	16,336,298		16,336,298	$6.34	14,820,045		14,820,045
September 2, 2020	$6.82	16,192,785		16,192,785	$7.52	14,689,852		14,689,852
December 2, 2020	$7.41	16,237,495		16,237,495	$8.17	14,730,412		14,730,412
March 3, 2021	$7.60	23,467,261		23,467,261	$8.38	21,289,147		21,289,147
June 2, 2021	$7.97	22,987,719		22,987,719	$8.79	20,854,114		20,854,114
September 8, 2021	$9.30	22,911,423		22,911,423	$10.25	20,784,899		20,784,899
December 1, 2021	$13.00	23,121,518	3,919,482	27,041,000	$14.33	20,975,494	3,555,695	24,531,190
March 9, 2022	$13.50	21,761,269		21,761,269	$14.88	19,741,497		19,741,497
June 1, 2022	$13.90	22,280,473		22,280,473	$15.32	20,212,511		20,212,511
September 7, 2022	$13.45	22,404,023		22,404,023	$14.83	20,324,594		20,324,594
December 7, 2022	$12.99	22,233,203		22,233,203	$14.32	20,169,628		20,169,628
March 8, 2023	$12.50	21,522,877		21,522,877	$13.78	19,525,231		19,525,231
June 7, 2023	$12.73	22,026,639		22,026,639	$14.03	19,982,237		19,982,237
September 6, 2023	$13.85	21,948,358		21,948,358	$15.27	19,911,221		19,911,221
December 6, 2023	$14.88	22,090,709	5,565,291	27,656,000	$16.40	20,040,360	5,048,749	25,089,108
March 13, 2024	$16.00	15,855,879	8,416,278	24,272,157	$17.64	14,384,216	7,635,121	22,019,337
June 5, 2024	$21.03	16,053,188		16,053,188	$23.18	14,563,211		14,563,211
September 4, 2024	$25.75	15,943,608		15,943,608	$28.38	14,463,802		14,463,802
December 4, 2024	$20.05	15,943,608		15,943,608	$22.10	14,463,802		14,463,802
March 12, 2025	$19.76	15,392,222	8,134,778	23,527,000	$21.78	13,963,593	7,379,749	21,343,341
June 4, 2025	$19.93	15,244,479		15,244,479	$21.97	13,829,563		13,829,563
September 3, 2025	$22.25	15,177,783		15,177,783	$24.53	13,769,057		13,769,057
December 4, 2025	$26.73	15,230,235		15,230,235	$29.46	13,816,641		13,816,641
March 11, 2026	$24.99	18,234,876	7,853,278	26,088,154	$27.55	16,542,406	7,124,376	23,666,782

129 See Regional Greenhouse Gas Initiative, "Auction Results," <https://www.rggi.org/auctions/auction-results>.

The RGGI auction held on March 11, 2026, generated $651.9 million in auction revenue. RGGI auctions have generated $10.8 billion in auction revenue since 2008.[130] RGGI auction revenue is returned to the states. RGGI reported that the RGGI states, cumulative through the 2022 reporting year, have invested $4.9 billion, 67.8 percent of auction revenues.[131] RGGI reports that 56 percent of the $4.9 billion was invested in energy efficiency, 12 percent on clean and renewable energy, seven percent on greenhouse gas abatement, 15 percent on direct bill assistance, five percent on beneficial electrification, six percent on administration and one percent on RGGI, Inc.[132]

If all PJM states joined RGGI, the total RGGI revenue to the PJM states would be significant. The estimated allowance revenue for PJM states based on 2025 CO_2 emission levels and the RGGI clearing price for the March 2026 auction ranges from $4.7 billion per year to $8.9 billion per year depending on associated reductions in carbon emission levels (Table 8-5).[133] Table 8-5 shows the estimated carbon allowance revenue for each PJM state based on the latest RGGI auction price and reductions below 2025 CO_2 emission levels ranging from five to 50 percent. A power plant owner must acquire an allowance for each ton of CO_2 emissions and the revenue values in Table 8-5 are computed by multiplying the carbon price by the emission cap level which is expressed as a reduction below the 2025 actual emissions level. States that participate in RGGI choose their emission cap. For example, New Jersey chose an emission cap of 18,000,000 short tons for reentry into RGGI in 2020, 5.3 percent below New Jersey's 2018 CO_2 emissions level; the New Jersey emission cap will be reduced by 540,000 short tons each year through 2030.[134]

Table 8-5 Estimated CO_2 allowance revenue at March 2026 RGGI price level[135] [136]

		Estimated CO2 allowance revenue ($ millions), carbon price $24.99 per short ton					
Jurisdiction	2025 power generation CO2 emissions (million short tons)	5 percent reduction below 2025 emission levels	10 percent reduction below 2025 emission levels	15 percent reduction below 2025 emission levels	20 percent reduction below 2025 emission levels	25 percent reduction below 2025 emission levels	50 percent reduction below 2025 emission levels
Delaware	2.4	$57.2	$54.2	$51.2	$48.1	$45.1	$30.1
Illinois	33.9	$805.9	$763.5	$721.1	$678.7	$636.3	$424.2
Indiana	41.3	$981.4	$929.8	$878.1	$826.5	$774.8	$516.5
Kentucky	32.0	$760.8	$720.8	$680.7	$640.7	$600.6	$400.4
Maryland	10.4	$247.8	$234.7	$221.7	$208.7	$195.6	$130.4
Michigan	2.3	$54.7	$51.8	$48.9	$46.1	$43.2	$28.8
New Jersey	10.1	$238.6	$226.1	$213.5	$201.0	$188.4	$125.6
North Carolina	0.1	$3.5	$3.3	$3.1	$2.9	$2.8	$1.8
Ohio	78.7	$1,868.9	$1,770.5	$1,672.1	$1,573.8	$1,475.4	$983.6
Pennsylvania	79.7	$1,892.0	$1,792.4	$1,692.8	$1,593.3	$1,493.7	$995.8
Tennessee	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	33.3	$791.4	$749.8	$708.1	$666.5	$624.8	$416.5
Washington, D.C.	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	50.9	$1,209.6	$1,145.9	$1,082.2	$1,018.6	$954.9	$636.6
Total	375.4	$8,911.8	$8,442.8	$7,973.7	$7,504.7	$7,035.7	$4,690.4

The RGGI emissions cap (carbon budget) is the sum of CO_2 allowances issued by each state. Table 8-6 shows the RGGI emission cap history. Compliance with the RGGI allowance obligation is evaluated at the end of each three year period which is called the control period. The first control period began in 2009. The 2026 compliance year is the third year of the sixth control period.

130 See Auction Results at <https://www.rggi.org/>.
131 *The Investment of RGGI Proceeds in 2023*, The Regional Greenhouse Gas Initiative (RGGI) at 16, July 2025, <https://www.rggi.org/investments/proceeds-investments>.
132 *Id.* at 15.
133 This assumes that the PJM states would implement their RGGI rules consistent with the current RGGI states where owners of fossil fuel generators are required to purchase emission allowances in a regional centralized auction or purchase allowances in a secondary market.
134 "Governor Murphy Announces Adoption of Rules Returning New Jersey to Regional Greenhouse Gas Initiative," State of New Jersey, Governor Phil Murphy Press Release, June 17, 2019 <https://nj.gov/governor/news/news/562019/approved/20190617a.shtml>.

135 The 2024 CO_2 emissions data is from the EPA Continuous Emission Monitoring System (CEMS) from PJM generators.
136 Power generation companies subject to a RGGI emission cap can offset up to 3.3 percent of their allowance obligation by undertaking certain greenhouse gas emission reduction projects. The allowance revenue values in Table 8-5 do not reflect offset allowances.

In 2021, RGGI announced a third adjustment to the RGGI emissions cap to account for banked allowances from previous control periods.[137] [138] The first adjustment removed 57.4 million allowances that were banked or unused from the first control period. The reduction to the RGGI emissions cap was spread over a seven year period beginning in 2014 and ending with 2020.[139] A second cap adjustment, corresponding to banked allowances for 2012 and 2013, began in 2015 with an adjustment of 13.7 million allowances per year and was in place through 2020.[140] The third adjustment of 95.5 million allowances will be spread over a five year period beginning in 2021.[141] The base emissions cap for each of the next five years will be reduced by 19.1 million allowances. There are no adjustments in place beginning with the 2026 compliance year. The percent change columns in Table 8-6 show the year to year percent changes in the base RGGI cap and the adjusted RGGI cap.[142] The budget for increased 17.9 percent in comparison to the 2025 adjusted budget. Figure 8-2 shows that the carbon budgets (CO_2 emissions caps) for all RGGI states increased in comparison to the 2025 adjusted budgets.

Table 8-6 RGGI emissions cap history[143] [144]

	Control Period	RGGI Average Clearing Price ($ per short ton)	RGGI Cap (short tons)	Percent Change in RGGI Cap	RGGI Adjusted Cap (short tons)	Percent Change in Adjusted Cap
2009	1st	$2.77	188,076,976		188,076,976	
2010		$1.93	188,076,976	0.0%	188,076,976	0.0%
2011		$1.89	188,076,976	0.0%	188,076,976	0.0%
2012	2nd	$1.93	165,184,246	0.0%	165,184,246	0.0%
2013		$2.92	165,184,246	0.0%	165,184,246	0.0%
2014		$4.72	91,000,000	(44.9%)	82,792,336	(49.9%)
2015	3rd	$6.10	88,725,000	(2.5%)	66,833,592	(19.3%)
2016		$4.47	86,506,875	(2.5%)	64,615,467	(3.3%)
2017		$3.42	84,344,203	(2.5%)	62,452,795	(3.3%)
2018	4th	$4.41	82,235,598	(2.5%)	60,344,190	(3.4%)
2019		$5.43	80,363,945	(2.3%)	58,472,538	(3.1%)
2020		$6.41	96,354,847	(2.5%)	74,463,439	(3.4%)
2021	5th	$9.61	119,767,784	(3.9%)	100,677,454	4.5%
2022		$13.46	116,112,784	(3.1%)	97,022,454	(3.6%)
2023		$13.58	112,457,784	(3.1%)	93,367,454	(3.8%)
2024	6th	$20.17	84,162,784	(3.2%)	69,401,609	(3.9%)
2025		$21.88	81,347,784	(3.3%)	66,586,609	(4.1%)
2026		$24.99	78,532,784	(3.5%)	78,532,784	17.9%

137 "Third Adjustment for Banked Allowances Announcement," Regional Greenhouse Gas Initiative (March 15, 2021) <https://www.rggi.org/news-releases/rggi-releases>.

138 A banked allowance is an allowance acquired during a previous control period that was not used to fulfill a RGGI allowance obligation.

139 "Second Control Period Interim Adjustment for Banked Allowances Announcement," Regional Greenhouse Gas Initiative (March 17, 2014) at 2. Due to rounding, the adjustment is 8,207,664 allowances for years 2014 through 2018, and 8,207,663 allowances for the remaining two years <https://www.rggi.org/sites/default/files/Uploads/Design-Archive/2012-Review/Adjustments/2014_03_17_SCP_Adjustment.pdf>.

140 Id.

141 "Third Adjustment for Banked Allowances Announcement," Regional Greenhouse Gas Initiative (March 15, 2021) <https://www.rggi.org/news-releases/rggi-releases>.

142 Percent changes for years with membership changes do not reflect the impacts of changes in membership. For example, the RGGI cap for 2020 reflects the impact of New Jersey rejoining RGGI in 2020 but the percent change from 2019 to 2020 does not include New Jersey's allowance budget. Virginia's adoption of RGGI in 2021 to 2023 and Virginia's withdrawal at the end of 2023 through 2025 are treated analogously.

143 See Regional Greenhouse Gas Initiative, "Allowance Distribution" <https://www.rggi.org/allowance-tracking/allowance-distribution> (Accessed April 21, 2025).

144 The increase in the RGGI Cap and the RGGI Adjusted Cap in 2020 is due to the reentry of New Jersey. The new cap is 18 million short tons higher than the previously published 2020 caps.

Figure 8-2 RGGI adjusted carbon budgets by state[145]

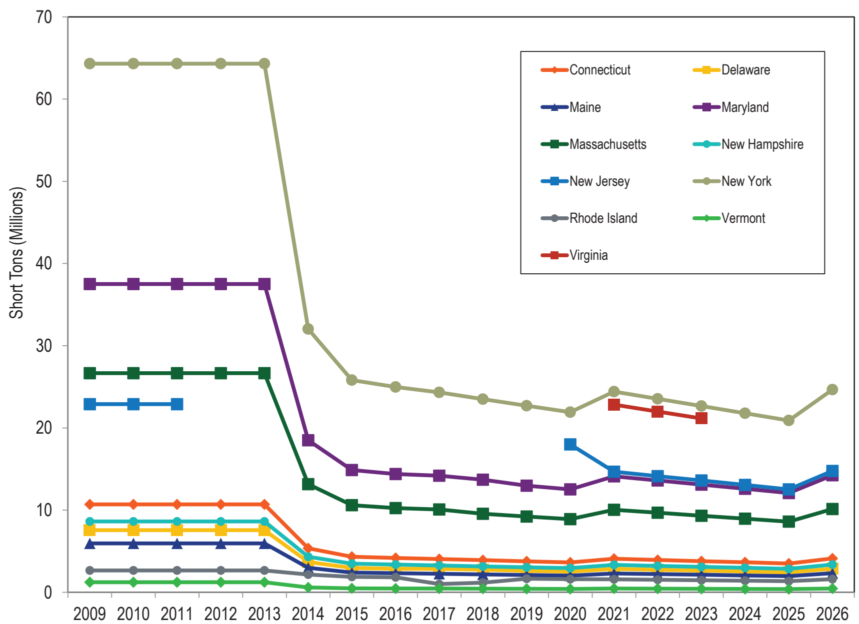


Table 8-7 shows the type of fuel and technology by marginal resources subjected to RGGI regulations and other marginal resources in the real-time energy market in the first three months of 2026 and 2025. In the first three months of 2026, marginal resources subjected to RGGI regulations accounted for 11.2 percent of all marginal resources. In the first three months of 2025, marginal resources subjected to RGGI regulations accounted for 12.3 percent of all marginal resources.

Table 8-7 Type of fuel used and technology (Real-time marginal units and RGGI marginal units): January through March, 2025 and 2026

		2025 (Jan - Mar)			2026 (Jan - Mar)		
Fuel	Technology	RGGI	Other	Total	RGGI	Other	Total
Gas	CC	9.73%	53.18%	62.90%	9.89%	45.62%	55.51%
Gas	CT	0.44%	6.05%	6.49%	0.74%	7.32%	8.06%
Oil	CT	0.02%	1.35%	1.37%	0.24%	1.64%	1.88%
Coal	Steam	0.20%	7.88%	8.08%	0.23%	9.39%	9.61%
Oil	Steam	0.04%	0.01%	0.05%	0.06%	0.05%	0.12%
Oil	RICE	1.75%	0.23%	1.98%	0.02%	0.12%	0.14%
Gas	Steam	0.01%	0.90%	0.91%	0.02%	1.61%	1.63%
Oil	CC	0.08%	0.10%	0.18%	0.02%	0.03%	0.05%
Other	Solar	0.00%	1.15%	1.15%	0.00%	1.58%	1.58%
Landfill Gas	CT	0.00%	0.01%	0.01%	0.00%	0.00%	0.00%
Other	Battery	0.00%	0.01%	0.01%	0.00%	0.03%	0.03%
Municipal Waste	RICE	0.00%	0.09%	0.09%	0.00%	0.06%	0.06%
Other	Steam	0.00%	0.05%	0.05%	0.00%	0.04%	0.04%
Wind	Wind	0.00%	15.82%	15.82%	0.00%	20.23%	20.23%
Gas	RICE	0.00%	0.82%	0.82%	0.00%	0.75%	0.75%
Municipal Waste	Steam	0.00%	0.06%	0.06%	0.00%	0.12%	0.12%
Uranium	Steam	0.00%	0.01%	0.01%	0.00%	0.20%	0.20%
All Marginal Units		12.27%	87.73%	100.00%	11.22%	88.78%	100.00%

Carbon Pricing, State Revenues and Energy Market Prices

Table 8-8 shows the estimated allowance revenue for PJM states for carbon prices ranging from $20 per short ton to $50 per short ton and for emissions reductions ranging from five percent to 50 percent. Allowance revenues to states would be $17.8 billion if the carbon price were $50 per short ton and emission levels were five percent below 2025 levels. Allowance revenues to states would be $3.8 billion if the carbon price were $20 per short ton and emission levels were 50 percent below 2025.

145 Data for the figure was collected from allowance distribution reports available on the RGGI website <https://www.rggi.org/allowance-tracking/allowance-distribution>

Table 8-8 Estimated CO_2 allowance revenue at various carbon prices

	Estimated CO2 allowance revenue ($ millions)					
Jurisdiction	5 percent reduction below 2025 emission levels	10 percent reduction below 2025 emission levels	15 percent reduction below 2025 emission levels	20 percent reduction below 2025 emission levels	25 percent reduction below 2025 emission levels	50 percent reduction below 2025 emission levels
Carbon Price ($ per short ton)			$20.00			
Delaware	$45.8	$43.3	$40.9	$38.5	$36.1	$24.1
Illinois	$645.0	$611.1	$577.1	$543.2	$509.2	$339.5
Indiana	$785.5	$744.1	$702.8	$661.4	$620.1	$413.4
Kentucky	$608.9	$576.9	$544.8	$512.8	$480.7	$320.5
Maryland	$198.3	$187.9	$177.4	$167.0	$156.6	$104.4
Michigan	$43.8	$41.5	$39.2	$36.9	$34.6	$23.0
New Jersey	$191.0	$180.9	$170.9	$160.8	$150.8	$100.5
North Carolina	$2.8	$2.7	$2.5	$2.4	$2.2	$1.5
Ohio	$1,495.7	$1,417.0	$1,338.3	$1,259.5	$1,180.8	$787.2
Pennsylvania	$1,514.2	$1,434.5	$1,354.8	$1,275.1	$1,195.4	$796.9
Tennessee	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	$633.4	$600.1	$566.7	$533.4	$500.1	$333.4
Washington, D.C.	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	$968.0	$917.1	$866.1	$815.2	$764.2	$509.5
Total	$7,132.3	$6,756.9	$6,381.5	$6,006.2	$5,630.8	$3,753.9
Carbon Price ($ per short ton)			$25.00			
Delaware	$57.2	$54.2	$51.2	$48.2	$45.2	$30.1
Illinois	$806.3	$763.8	$721.4	$678.9	$636.5	$424.3
Indiana	$981.8	$930.1	$878.5	$826.8	$775.1	$516.7
Kentucky	$761.1	$721.1	$681.0	$640.9	$600.9	$400.6
Maryland	$247.9	$234.8	$221.8	$208.7	$195.7	$130.5
Michigan	$54.7	$51.8	$49.0	$46.1	$43.2	$28.8
New Jersey	$238.7	$226.2	$213.6	$201.0	$188.5	$125.7
North Carolina	$3.5	$3.3	$3.1	$2.9	$2.8	$1.8
Ohio	$1,869.6	$1,771.2	$1,672.8	$1,574.4	$1,476.0	$984.0
Pennsylvania	$1,892.7	$1,793.1	$1,693.5	$1,593.9	$1,494.3	$996.2
Tennessee	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	$791.8	$750.1	$708.4	$666.7	$625.1	$416.7
Washington, D.C.	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	$1,210.0	$1,146.4	$1,082.7	$1,019.0	$955.3	$636.9
Total	$8,915.4	$8,446.2	$7,976.9	$7,507.7	$7,038.5	$4,692.3
Carbon Price ($ per short ton)			$50.00			
Delaware	$114.4	$108.4	$102.3	$96.3	$90.3	$60.2
Illinois	$1,612.5	$1,527.6	$1,442.8	$1,357.9	$1,273.0	$848.7
Indiana	$1,963.6	$1,860.3	$1,756.9	$1,653.6	$1,550.2	$1,033.5
Kentucky	$1,522.3	$1,442.1	$1,362.0	$1,281.9	$1,201.8	$801.2
Maryland	$495.8	$469.7	$443.6	$417.5	$391.4	$260.9
Michigan	$109.5	$103.7	$97.9	$92.2	$86.4	$57.6
New Jersey	$477.5	$452.3	$427.2	$402.1	$377.0	$251.3
North Carolina	$7.0	$6.6	$6.3	$5.9	$5.5	$3.7
Ohio	$3,739.2	$3,542.4	$3,345.6	$3,148.8	$2,952.0	$1,968.0
Pennsylvania	$3,785.5	$3,586.3	$3,387.0	$3,187.8	$2,988.5	$1,992.4
Tennessee	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	$1,583.5	$1,500.2	$1,416.8	$1,333.5	$1,250.1	$833.4
Washington, D.C.	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	$2,420.1	$2,292.7	$2,165.3	$2,038.0	$1,910.6	$1,273.7
Total	$17,830.8	$16,892.3	$15,953.9	$15,015.4	$14,076.9	$9,384.6

Table 8-9 shows the estimated impact of five different carbon prices on PJM load-weighted LMP. For example, if the carbon price were $15.00 per tonne, the PJM load-weighted average LMP in the first three months of 2026 would have decreased by 0.8 percent.[146]

Table 8-9 Estimated impact of carbon price on LMP: January through March, 2025 and 2026

	2025 (Jan - Mar)				2026 (Jan - Mar)		
Scenario	Carbon Price ($/Metric Ton)	Actual LMP ($/MWh)	Estimated LMP ($/MWh)	Percent Change	Actual LMP ($/MWh)	Estimated LMP ($/MWh)	Percent Change
Scenario 1	$5.00	$52.20	$49.54	(5.1%)	$87.57	$86.12	(1.7%)
Scenario 2	$10.00	$52.20	$50.36	(3.5%)	$87.57	$86.49	(1.2%)
Scenario 3	$15.00	$52.20	$51.17	(2.0%)	$87.57	$86.86	(0.8%)
Scenario 4	$25.00	$52.20	$52.80	1.2%	$87.57	$87.59	0.0%
Scenario 5	$50.00	$52.20	$56.88	9.0%	$87.57	$89.43	2.1%

Table 8-10 shows the impact of a range of carbon prices on the cost per MWh of producing energy from three basic unit types.[147] [148] For example, if the price of carbon were $50.00 per tonne, the short run marginal costs would increase by $24.45 per MWh for a new combustion turbine (CT) unit, $16.85 per MWh for a new combined cycle (CC) unit and $43.12 per MWh for a new coal plant (CP). Table 8-12 and Table 8-13 show the carbon price impact ($ per MWh) for a range of heat rates and carbon prices for natural gas and coal fired generation.

Table 8-10 Carbon price per MWh by unit type

	Carbon Price per MWh						
Unit Type	Carbon $5/ tonne	Carbon $10/ tonne	Carbon $15/ tonne	Carbon $50/ tonne	Carbon $100/tonne	Carbon $200/tonne	Carbon $400/tonne
CT	$2.44	$4.89	$7.33	$24.45	$48.89	$97.79	$195.58
CC	$1.68	$3.37	$5.05	$16.85	$33.70	$67.40	$134.79
CP	$4.31	$8.62	$12.94	$43.12	$86.25	$172.49	$344.99

Table 8-10 also illustrates the effective cost of carbon included in the price of a REC or SREC. For example, the average price of an SREC in New Jersey was $184.51 per credit in the first three months of 2026. The SREC price is paid in addition to the energy price paid at the time the solar energy is produced. The carbon price implied by the SREC price is slightly less than $400 per tonne. Table 8-10 shows that if the MWh produced by the solar resource resulted in avoiding the production of one MWh from a CT, the value of carbon reduction implied by an SREC price of $195.58 is a carbon price of $400 per tonne. This result also assumes that the entire value of the SREC was based on reduced carbon emissions. The SREC price consistent with a carbon price of $50.00 per tonne, assuming that a MWh from a CT is avoided, is $24.45 per MWh.

Applying this method to Tier I and Class I REC, and SREC price histories yields the implied carbon prices in Table 8-11. The carbon price implied by the average REC price in the first three months in Ohio is $8.89 per tonne which is less than a third of the March 2026 RGGI auction clearing price of $27.55 per tonne. The implied carbon prices for RECs in the other jurisdictions in Table 8-11 range from $50.97 per tonne to $65.30 per ton. The implied carbon price for Virginia RECs is $65.30, 2.4 times the March 2026 RGGI auction clearing price. The social cost of carbon is estimated to be in the range of $50 per tonne.[149] [150] The carbon prices implied by SREC prices have no apparent relationship to carbon prices implied by the REC clearing prices. The carbon prices implied by the SREC prices all exceed the carbon prices implied by the corresponding REC prices.

146 LMPs are recalculated to account for the defined cost of carbon emissions on marginal units' offer prices. The LMP calculation is not based on a counterfactual redispatch of the system to determine the marginal units and the marginal costs that would have occurred if all units had made all offers at short run marginal cost. See Technical Reference for PJM Markets, "Calculation and Use of Generator Sensitivity/Unit Participation Factors," <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

147 Heat rates from: *2025 Annual State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue, Table 7-3.

148 Prices reflect carbon emissions rates from *Table A.3. Carbon Dioxide Uncontrolled Emission Factors*, EIA, <https://www.eia.gov/electricity/annual/html/epa_a_03.html> (Accessed May 7, 2024).

149 "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>.

150 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>.

Table 8-11 Implied carbon price based on REC and SREC prices: 2015 through March 2026

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Jurisdiction with Tier I or Class I REC												
Maryland	$29.27	$26.17	$23.19	$21.35	$17.81	$19.98	$34.29	$37.82	$46.80	$50.02	$50.77	$50.97
New Jersey	$25.37	$27.01	$24.08	$22.08	$19.25	$20.54	$31.62	$36.23	$48.37	$53.60	$59.52	$63.73
Ohio	$8.54	$5.30	$6.29	$11.21	$14.04	$16.33	$14.93	$14.98	$13.04	$11.35	$9.78	$8.89
Pennsylvania	$28.96	$26.43	$23.42	$21.53	$17.96	$20.06	$33.58	$37.76	$46.68	$51.93	$55.58	$56.84
Virginia							$35.53	$36.02	$51.93	$62.11	$62.80	$65.30
Washington, D.C.	$3.20	$4.05	$4.90	$4.69	$5.52	$20.25	$24.28	$27.49	$33.95	$47.41	$49.28	$57.20
Jurisdiction with Solar REC												
Maryland	$251.99	$183.64	$128.05	$87.27	$84.19	$101.68	$121.11	$111.74	$104.44	$108.14	$105.45	$89.35
New Jersey	$389.91	$425.49	$460.60	$446.35	$410.31	$394.18	$413.80	$424.70	$399.25	$396.71	$384.67	$377.37
Ohio	$45.25	$36.26	$31.92	$21.73	$26.65							
Pennsylvania	$67.09	$55.22	$43.97	$28.16	$51.65	$63.80	$74.20	$83.02	$78.95	$72.14	$67.41	$66.90
Washington, D.C.	$997.05	$996.49	$868.78	$842.89	$851.39	$869.41	$851.78	$856.50	$867.74	$794.05	$826.79	$840.02
Regional Greenhouse Gas Initiative												
RGGI clearing price	$6.72	$4.93	$3.77	$4.86	$5.98	$7.06	$10.59	$14.84	$14.97	$22.23	$24.12	$27.55

Table 8-12 Carbon price for natural gas fired generators[151]

	Carbon Price ($ per MWh)										
	Carbon ($ per tonne)										
Heat Rate (Btu per kWh)	**$10.00**	**$15.00**	**$20.00**	**$25.00**	**$30.00**	**$35.00**	**$40.00**	**$45.00**	**$50.00**	**$55.00**	**$60.00**
6,000	$3.17	$4.76	$6.35	$7.94	$9.52	$11.11	$12.70	$14.29	$15.87	$17.46	$19.05
6,500	$3.44	$5.16	$6.88	$8.60	$10.32	$12.04	$13.76	$15.48	$17.20	$18.92	$20.63
7,000	$3.70	$5.56	$7.41	$9.26	$11.11	$12.96	$14.81	$16.67	$18.52	$20.37	$22.22
7,500	$3.97	$5.95	$7.94	$9.92	$11.90	$13.89	$15.87	$17.86	$19.84	$21.83	$23.81
8,000	$4.23	$6.35	$8.47	$10.58	$12.70	$14.81	$16.93	$19.05	$21.16	$23.28	$25.40
8,500	$4.50	$6.75	$8.99	$11.24	$13.49	$15.74	$17.99	$20.24	$22.49	$24.74	$26.98
9,000	$4.76	$7.14	$9.52	$11.90	$14.29	$16.67	$19.05	$21.43	$23.81	$26.19	$28.57
9,500	$5.03	$7.54	$10.05	$12.57	$15.08	$17.59	$20.11	$22.62	$25.13	$27.65	$30.16
10,000	$5.29	$7.94	$10.58	$13.23	$15.87	$18.52	$21.16	$23.81	$26.45	$29.10	$31.75
10,500	$5.56	$8.33	$11.11	$13.89	$16.67	$19.44	$22.22	$25.00	$27.78	$30.56	$33.33
11,000	$5.82	$8.73	$11.64	$14.55	$17.46	$20.37	$23.28	$26.19	$29.10	$32.01	$34.92
11,500	$6.08	$9.13	$12.17	$15.21	$18.25	$21.30	$24.34	$27.38	$30.42	$33.47	$36.51
12,000	$6.35	$9.52	$12.70	$15.87	$19.05	$22.22	$25.40	$28.57	$31.75	$34.92	$38.10
12,500	$6.61	$9.92	$13.23	$16.53	$19.84	$23.15	$26.45	$29.76	$33.07	$36.38	$39.68
13,000	$6.88	$10.32	$13.76	$17.20	$20.63	$24.07	$27.51	$30.95	$34.39	$37.83	$41.27
13,500	$7.14	$10.71	$14.29	$17.86	$21.43	$25.00	$28.57	$32.14	$35.71	$39.29	$42.86
14,000	$7.41	$11.11	$14.81	$18.52	$22.22	$25.93	$29.63	$33.33	$37.04	$40.74	$44.44
14,500	$7.67	$11.51	$15.34	$19.18	$23.02	$26.85	$30.69	$34.52	$38.36	$42.20	$46.03
15,000	$7.94	$11.90	$15.87	$19.84	$23.81	$27.78	$31.75	$35.71	$39.68	$43.65	$47.62

151 Prices reflect uncontrolled carbon emission rates from Table A.3 in *Electric Power Annual*, EIA (October 19, 2023) <https://www.eia.gov/electricity/annual/>.

Table 8-13 Carbon price for coal fired generators[152]

	Carbon Price ($ per MWh)										
	Carbon ($ per tonne)										
Heat Rate (Btu per kWh)	$10.00	$15.00	$20.00	$25.00	$30.00	$35.00	$40.00	$45.00	$50.00	$55.00	$60.00
9,000	$8.39	$12.59	$16.78	$20.98	$25.17	$29.37	$33.57	$37.76	$41.96	$46.15	$50.35
9,500	$8.86	$13.29	$17.72	$22.14	$26.57	$31.00	$35.43	$39.86	$44.29	$48.72	$53.15
10,000	$9.32	$13.99	$18.65	$23.31	$27.97	$32.63	$37.30	$41.96	$46.62	$51.28	$55.94
10,500	$9.79	$14.69	$19.58	$24.48	$29.37	$34.27	$39.16	$44.06	$48.95	$53.85	$58.74
11,000	$10.26	$15.38	$20.51	$25.64	$30.77	$35.90	$41.03	$46.15	$51.28	$56.41	$61.54
11,500	$10.72	$16.08	$21.45	$26.81	$32.17	$37.53	$42.89	$48.25	$53.61	$58.97	$64.34
12,000	$11.19	$16.78	$22.38	$27.97	$33.57	$39.16	$44.76	$50.35	$55.94	$61.54	$67.13
12,500	$11.65	$17.48	$23.31	$29.14	$34.96	$40.79	$46.62	$52.45	$58.27	$64.10	$69.93
13,000	$12.12	$18.18	$24.24	$30.30	$36.36	$42.42	$48.48	$54.55	$60.61	$66.67	$72.73
13,500	$12.59	$18.88	$25.17	$31.47	$37.76	$44.06	$50.35	$56.64	$62.94	$69.23	$75.52
14,000	$13.05	$19.58	$26.11	$32.63	$39.16	$45.69	$52.21	$58.74	$65.27	$71.79	$78.32
14,500	$13.52	$20.28	$27.04	$33.80	$40.56	$47.32	$54.08	$60.84	$67.60	$74.36	$81.12
15,000	$13.99	$20.98	$27.97	$34.96	$41.96	$48.95	$55.94	$62.94	$69.93	$76.92	$83.92
15,500	$14.45	$21.68	$28.90	$36.13	$43.36	$50.58	$57.81	$65.03	$72.26	$79.49	$86.71
16,000	$14.92	$22.38	$29.84	$37.30	$44.76	$52.21	$59.67	$67.13	$74.59	$82.05	$89.51
16,500	$15.38	$23.08	$30.77	$38.46	$46.15	$53.85	$61.54	$69.23	$76.92	$84.62	$92.31
17,000	$15.85	$23.78	$31.70	$39.63	$47.55	$55.48	$63.40	$71.33	$79.25	$87.18	$95.10
17,500	$16.32	$24.48	$32.63	$40.79	$48.95	$57.11	$65.27	$73.43	$81.58	$89.74	$97.90
18,000	$16.78	$25.17	$33.57	$41.96	$50.35	$58.74	$67.13	$75.52	$83.92	$92.31	$100.70

State Renewables Regulation

State Renewable Portfolio Standards (RPS)

Ten of 14 PJM jurisdictions have enacted legislation that requires that a defined percentage of retail load be served by renewable resources, for which there are many standards and definitions. These requirements are known as renewable portfolio standards, or RPS. In PJM jurisdictions that have adopted an RPS, load serving entities are required by law to meet defined shares of load using specific renewable and/or alternative energy sources commonly called eligible technologies. Load serving entities may generally fulfill these obligations in one of two ways: they may use their own generation resources classified as eligible technologies to produce power or they may purchase renewable energy credits (RECs) that represent a known quantity of power produced with eligible technologies by other market participants or in other geographical locations. Load serving entities that fail to meet the percent goals set in their jurisdiction's RPS must pay penalties (alternative compliance payments).

Renewable energy sources replenish naturally in a short period of time but are flow limited and include solar, geothermal, wind, biomass and hydropower from flowing water. Renewable energy sources are virtually inexhaustible in duration but limited in the amount of energy that is available per unit of time. Nonrenewable energy sources do not replenish in a short period of time and include crude oil, natural gas, coal and uranium (nuclear energy).[153] Some state rules allow nonrenewable energy sources as part of their Renewable Portfolio Standard.

As of March 31, 2025, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Virginia and Washington, DC had mandatory renewable portfolio standards that include penalties.

As of March 31, 2025, Indiana had voluntary renewable portfolio standards that do not require participation and do not include noncompliance penalties. Incentives are offered to load serving entities to develop renewable generation or, to a more limited extent, purchase RECs. The voluntary standard was enacted by the Indiana legislature in 2011, but no load serving entities have volunteered to participate in the program.[154]

As of March 31, 2025, Kentucky, Tennessee and West Virginia had no renewable portfolio standards.

How each state satisfies its renewable portfolio standard requirements should be more transparent. While some jurisdictions publish transparent information regarding total REC generation, how the standard is fulfilled and the total cost to the state, some jurisdictions do not provide the same level of detail and there can be a significant lag from the end of the compliance year to the publication of the information. Some states provide adequate information with respect to the total cost for the RPS, where the RECs originated that

152 Prices reflect carbon emission rates for refined coal in *Table A.3. Carbon Dioxide Uncontrolled Emission Factors*, EIA, <https://www.eia.gov/electricity/annual/html/epa_a_03.html> (Accessed May 7, 2024).

153 *Renewable Energy Explained*, U.S. Energy Information Administration, <https://www.eia.gov/energyexplained/index.php?page=renewable_home> (Accessed May 7, 2024).

154 See the Indiana Utility Regulatory Commission's "2021 Annual Report," at 37 (Oct. 2021) <https://www.in.gov/iurc/2981.htm>.

fulfill the RPS requirements, and if the state fulfilled the RPS goals. Pennsylvania and Maryland both provide more information than other states and serve as a model for other states. The MMU recommends that jurisdictions with a renewable portfolio standard make the compliance data and cost data available in a more complete and transparent manner.

Since a REC may be applied in years other than the year in which it was generated, each vintage of RECs for each state has a different price. For example, the Pennsylvania Alternative Energy Portfolio Standard allows an electric distribution company or generation supplier to retain RECs from the current reporting year for use toward satisfying their REC obligation in either of the two subsequent reporting years.[155]

Beginning in March 2023, RECs for GATS generators are hourly time stamped certificates.[156] Prior to March 2023, PJM EIS issued RECs based on how much a generator produced in a month.

Table 8-14 shows the percent of retail electric load that must be served by renewable and/or alternative energy resources under each PJM jurisdictions' RPS by year.

Table 8-14 Renewable and alternative energy standards of PJM jurisdictions: 2025 to 2035[157] [158] [159]

Jurisdiction with RPS	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Delaware	25.00%	25.50%	26.00%	26.50%	27.00%	28.00%	30.00%	32.00%	34.00%	37.00%	40.00%
Illinois	25.00%	28.00%	31.00%	34.00%	37.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
Maryland	38.00%	40.50%	44.00%	45.50%	52.00%	52.50%	52.50%	52.50%	52.50%	52.50%	52.50%
Michigan	15.00%	15.00%	15.00%	15.00%	15.00%	50.00%	50.00%	50.00%	50.00%	50.00%	60.00%
New Jersey	40.50%	43.50%	46.50%	49.50%	52.50%	52.50%	52.50%	52.50%			
North Carolina	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%
Ohio	8.00%	8.50%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Pennsylvania	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%
Virginia (Phase I utilities)	14.00%	17.00%	20.00%	24.00%	27.00%	30.00%	33.00%	36.00%	39.00%	42.00%	45.00%
Virginia (Phase II utilities)	26.00%	29.00%	32.00%	35.00%	38.00%	41.00%	45.00%	49.00%	52.00%	55.00%	59.00%
Washington, DC	52.00%	59.00%	66.00%	73.00%	80.00%	87.00%	94.00%	100.00%	100.00%	100.00%	100.00%

The Climate and Equitable Jobs Act (CEJA), which became effective on September 15, 2021, in Illinois, increased the RPS target percent from 25 percent by 2025 to 40 percent by 2030. CEJA also increased the quotas for RECs sourced from new wind and new photovoltaic resources, and made changes to eligible technologies and geographic restrictions. See Table 8-15 for details.

Updates to the Maryland RPS became effective on June 1, 2021. Maryland Senate Bill 65 changed the intermediate RPS target levels while maintaining the target of 50 percent renewable by 2030.[160] Part of the legislation was to eliminate resources fueled by black liquor as a Tier 1 eligible technology. Senate Bill

155 Pennsylvania General Assembly, "Alternative Energy Portfolio Standards Act – Enactment Act of Nov. 30, 2004, P.L. 1672, No. 213," Section (e)(6).
156 "PJM EIS to Produce Energy Certificates Hourly", PJM Environmental Information Services (February 13, 2023) <https://www.pjm-eis.com/-/media/about-pjm/newsroom/2023-releases/20230213-pjm-eis-to-produce-energy-certificates-hourly.ashx>.
157 This shows the total standard of alternative resources in all PJM jurisdictions, including Tier I and Tier II.
158 The table reflects calendar year standards for Maryland, Michigan, Washington, DC, Ohio, and North Carolina. The standards for the remaining jurisdictions are for compliance years that begin on June 1, CCYY and end on May 31 of the following year.
159 New Jersey Administrative Code, Section 14:8-2.3 does not specify standards beyond compliance year 2032/2033.
160 *Senate Bill 65 Electricity – Renewable Energy Portfolio Standard – Tier 2 Renewable Sources, Qualifying Biomass, and Compliance Fees*, Maryland General Assemble (2021) <https://mgaleg.maryland.gov/mgawebsite/Legislation/Details/sb0065?ys=2021RS>.

65 reduced the penalty for solar noncompliance from $100 per credit to $80 per credit, and extended the Tier 2 standard which was scheduled to expire with the 2020 compliance year.

The Delaware General Assembly passed new RPS legislation on February 10, 2021. The new law updates the Delaware RPS targets from 25 percent in 2025 to 40 percent in 2035.[161] Additional details are provided in Table 8-15.

On April 11, 2020, the Virginia legislature passed a new law that replaced Virginia's current voluntary RPS with a mandatory RPS.[162] The new law requires by 2050 that 100 percent of energy sold by phase I utilities must come from RPS eligible resources; and 100 percent of energy sold by phase II utilities must come from RPS eligible resources by 2045.[163] [164] Intermediate RPS targets begin in 2021 with a 6.0 percent standard for phase I utilities and a 14.0 percent standard for phase II utilities. Eligible RPS resources include wind, solar, hydroelectric, landfill gas and biomass resources.

In 2018, New Jersey passed legislation that included provisions promoting the development of solar power in the state.[165] The Board of Public Utilities is directed to develop and provide an orderly transition to a new or modified program to support distributed solar. The Board must also design a Community Solar Energy Pilot Program that would "permit customers of an electric public utility to participate in a solar energy project that is remotely located from their properties but is within their electric public utility service territory to allow for a credit to the customer's utility bill equal to the electricity generated that is attributed to the customer's participation in the solar energy project." The pilot program would convert into a permanent program within three years. The statute targets the development of 600 MW of electric storage by 2021 and 2,000 MW by 2030.

161 See Senate Bill 33, Delaware General Assembly (February 10, 2021) <https://legis.delaware.gov/BillDetail?legislationId=48278>.
162 See "Virginia Clean Economy Act," (April 12, 2020) <https://www.governor.virginia.gov/newsroom/all-releases/2020/april/headline-856056-en.html>.
163 A phase I utility is an investor-owned incumbent electric utility that was, as of July 1, 1999, not bound by a rate case settlement adopted by the Commission that extended in its application beyond January 1, 2002, and a phase II utility is an investor-owned incumbent electric utility that was bound by such a settlement (§ 56-585.1 of the Virginia Code).
164 APCO (AEP) is a phase I utility and Dominion Energy Virginia is a phase II utility. Cooperatives are not subject to the RPS
165 N.J. S. 2314/A. 3723.

On May 18, 2021, Maryland enacted legislation doubling the limit on net metered capacity from 1,500 to 3,000 MW.[166] The legislation is expected to boost the installation of distribution level solar power.

On July 9, 2021, New Jersey enacted legislation establishing a new program for SRECs under the BPU.[167] Through the SREC-II program, the BPU distribute solar renewable certificates to qualifying solar power facilities. The legislation includes incentives for at least 1,500 MW of behind the meter solar facilities and 750 MW of community solar by 2026. It also includes a new competitive solicitation process to incentivize at least 1,500 MW of large-scale solar power facilities by 2026, and develops siting criteria for large-scale solar projects.

166 Md. Code Ann § 7-306(d) & 7-306.2(g) (HB 569).
167 N.J. P.L.2021 (S. 2605/A 4554).

Table 8-15 summarizes recent rules changes in Ohio, Maryland, New Jersey, and Washington, DC.

Table 8-15 Recent changes in RPS rules[168] [169] [170] [171] [172] [173] [174] [175]

Jurisdiction	Legislation	Effective Date	Summary of changes
Michigan	Public Act 235 of 2023	February 27, 2024	Updated the RPS target to 60 percent by 2035. The current 15 percent standard remains in place through 2029 and then increases to 50 percent for 2030 through 2034.
Illinois	Climate and Equitable Jobs Act (Public Act 102-0662)	September 15, 2021	Updated the RPS target to 40.0 percent by 2030. The previous target of 25.0 percent by 2025 is still required. Updated the requirement for RECs from new wind generation from 2,000 GWH annually to 4,500 GWH beginning in the 2021/2022 delivery year; increasing to 20,250 GWH in 2030/2031. Updated the requirement for RECs from new photovoltaic generation from 2,000 GWH annually to 5,500 GWH beginning in the 2021/2022 delivery year; increasing to 24,750 GWH in 2030/2031. Removed tree waste as an energy source for eligible resources and added waste heat to power systems and qualified combined heat and power systems as eligible resources. Updated the geographic restrictions to allow RECs from utility scale wind or photovoltaic resources that are deliverable via high voltage direct current transmission.
Maryland	Senate Bill 65	June 1, 2021	Maintains theTier 1 target of 50.0 percent in 2030 with 14.5 percent solar carve out, but changes the intermediary target levels beginning in 2022. The alternatvie compliance payment for solar was reduced and the definition of Tier 1 resource now excludes generators fueled by black liquor. Extends indefinitely the Tier 2 target of 2.5 percent which was set to expire in 2020. Tier 2 resources are defined as hydroelectric power other than pumped storage.
Delaware	151st General Assembly Senate Bill 33	February 1, 2021	Increases the RPS target from 25.0 percent in 2025 to 40.0 percent in 2035. Sets the solar carve out requirement to 10.0 percent in 2035. Establishes intermediary target levels for total RPS and the solar carve out for compliance years 2026 through 2034. Lowered the solar alternative compliance payment (SACP) from $400 per credit to $150 per credit.
Virginia	Virginia Clean Economy Act	April 11, 2020	Replaces the voluntary RPS with a mandartory RPS beginning in January 2021. The legislation requires 100 percent clean energy by 2050 for phase I utilities and 100 percent clean energy by 2045 for phase II utilities. Intermediate target levels begin in 2021 with 6 percent for phase I utilities and 14 percent for phase II utilities.
Ohio	House Bill 6	October 22, 2019	Reduced the RPS percent for each year beginning in 2020. The 2020 standard was reduced from 6.5 percent to 5.5 percent; the 2026 standard was reduced from 12.5 percent to 8.5 percent. The legislation also removed language that had previously indicated that the standard would remain at the 2026 level for each year after 2026. The solar carve out was removed for compliance year 2020 and beyond. Prior to the recent legislation, the solar carve out was 0.26 percent for 2020, increased to 0.50 percent for 2026, and remained at 0.50 percent for subsequent years.
Maryland	Clean Energy Jobs Act	May 25, 2019	Established a new Tier I target of 50.0 percent in 2030; previously the 2030 Tier I standard was 25.0 percent. The 2019 Tier I standard increased from 20.4 percent to 20.7. The solar carve out percent for 2019 increased from 1.95 percent to 5.50 percent. The solar carve out percent for 2030 increased from 2.5 percent to 14.5 percent. The 2.5 percent Tier II standard, scheduled to end in 2018, was extended through 2020.
Washington, D.C.	CleanEnergy DC Omnibus Amendment Act of 2018	March 22, 2019	Established a 100 percent Tier I renewable standard by 2032. Previously, the 2032 target was 50.0 percent. Tier I increases start in 2020, going from 20.0 percent to 26.25 percent. The 2020 solar carve out will increase from 1.58 percent to 2.175 percent. The 2041 target for the solar carve out is 10.0 percent.

Each PJM jurisdiction with an RPS identifies the type of generation resources that may be used for compliance. These resources are often called eligible technologies. Some PJM jurisdictions with RPS group different eligible technologies into tiers based on the magnitude of their environmental impact. Of the ten PJM jurisdictions with mandatory RPS, Maryland, New Jersey, Pennsylvania, and Washington, DC group the eligible technologies that must be used to comply with their RPS programs into Tier I and Tier II resources.[176] Although there are minor differences across these four jurisdictions' definitions of Tier I resources, technologies that use solar photovoltaic, solar thermal, wind, ocean, tidal, biomass, low-impact hydro, and geothermal sources to produce electricity

168 Michigan Public Act 235 of 2023, Sec. 28.
169 Illinois Climate and Equitable Jobs Act (Public Act 102-0662), Section 90-30 (September 15, 2021).
170 See "Virginia Clean Economy Act," (April 12, 2020).
171 See Ohio Legislature House, 133rd Assembly, Bill No. 6, "Ohio Clean Air Program," effective Date October 22, 2019, <https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA133-HB-6>.
172 See Maryland State Legislature, Senate Bill No. 516, "Clean Energy Jobs," Passed May 25, 2019.
173 D.C. Law 22-257 "CleanEnergy DC Omnibus Amendment Act of 2018," Effective March 22, 2019.
174 See Senate Bill 33, Delaware General Assembly (February 10, 2021) <https://legis.delaware.gov/BillDetail?legislationId=48278>.
175 *Senate Bill 65 Electricity – Renewable Energy Portfolio Standard – Tier 2 Renewable Sources, Qualifying Biomass, and Compliance Fees*, Maryland General Assemble (2021) <https://mgaleg.maryland.gov/mgawebsite/Legislation/Details/sb0065?ys=2021RS>.
176 New Jersey separates technologies into Class I/Class II resources in a manner that is consistent with the other jurisdictions' Tier I/Tier II categorizations.

are classified as Tier I resources. Table 8-16 shows the Tier I standards for PJM states.[177] All eligible technologies for the RPS standards in Table 8-16 satisfy the EIA definition of renewable energy.[178]

Table 8-16 Tier I / Class I renewable standards of PJM jurisdictions: 2025 to 2035[179]

Jurisdiction with RPS	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Maryland	35.50%	38.00%	41.50%	43.00%	49.50%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%
New Jersey	38.00%	41.00%	44.00%	47.00%	50.00%	50.00%	50.00%	50.00%			
Pennsylvania	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
Washington, DC	52.00%	59.00%	66.00%	73.00%	80.00%	87.00%	94.00%	100.00%	100.00%	100.00%	100.00%

Delaware, Illinois, Michigan, North Carolina, Virginia and Ohio do not classify the resources eligible for their RPS standards by tiers. In these states eligible technologies are largely but not completely renewable resources.[180]

RECs do not need to be used during the year in which they are generated. The result is that there may be multiple prices for a REC based on the year in which it was generated. RECs typically have a shelf life of five years during which they can be used to satisfy a state's RPS requirement. For example if a load serving entity (LSE) owns renewable generation and the renewable generation exceeds the LSE's RECs purchase obligation for the current year, the LSE can either sell the REC to another LSE or hold the REC for use in a subsequent year.

PJM GATS makes data available for the amount of eligible RECs by jurisdiction. Eligible RECs are not the amount of actual RECs generated for that timeframe. A REC that is created may be eligible in multiple jurisdictions resulting in an over representation of generated RECs. This means if one REC is retired in Pennsylvania, the total amount of eligible RECs will reduce by more than one REC.

The REC prices are the average price for each vintage of REC, defined by the year in which the associated power was generated, regardless of when the REC is consumed. REC prices are required to be publicly disclosed in Maryland, Pennsylvania and Washington, DC, but in the other states REC prices are not publicly available.

177 This includes New Jersey's Class I renewable standard.
178 *Renewable Energy Explained*, U.S. Energy Information Administration, <https://www.eia.gov/energyexplained/index.php?page=renewable_home> (Accessed May 7, 2024).
179 New Jersey Administrative Code, Section 14:8-2.3 does not specify standards beyond compliance year 2032/2033.
180 Michigan's Public Act 342, effective April 20, 2017, removed nonrenewable technologies (e.g. coal gasification, industrial cogeneration, and coal with carbon capture) from the list of RPS eligible technologies.

Figure 8-3 shows the annual average Tier I REC price by jurisdiction from 2009 through March 2026. Tier I REC prices are lower than SREC prices. Several states have more stringent geographical restrictions for SRECs and higher alternative compliance payments (ACP) for SRECs than for RECs. For example, the average SREC price in the first three months of 2026 in Washington, DC was $410.72 and the average Tier I REC price in the first three months of 2026 in Washington, DC was $27.97. The DC RPS requires SRECs to be sourced from within DC while Tier I RECs may be sourced from anywhere within the PJM footprint. The DC solar ACP is $440 per SREC compared to $50 per REC for Tier I compliance.

Figure 8-3 Average Tier I REC price by jurisdiction: 2009 through March 2026

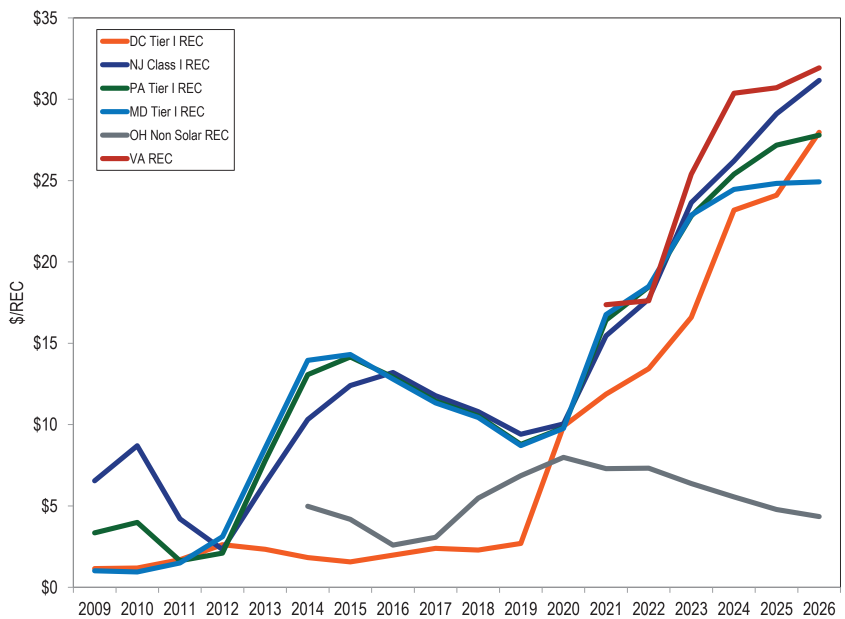


Figure 8-4 and Table 8-17 shows the fulfillment of Tier I equivalent RPS requirement for 2021 through 2025 by state and by carbon producing and noncarbon producing RECs.[181] Depending on the state, the RPS requirement can be fulfilled by wind, solar, hydro ("Carbon Free REC") or with landfill gas, captured methane, wood, black liquor, and other fuels. ("Carbon Producing REC"). States' Tier I requirements are not all carbon free. The Delaware and Illinois RPS are fulfilled by noncarbon RECs, but all other state Tier I equivalent RPS requirements allow carbon producing RECs to fulfill the RPS requirements. Figure 8-4 shows the use of in state, other PJM state and out of state carbon producing RECs and in state, other PJM state and out of state carbon free RECs by state to meet the RPS requirements. In Table 8-17 the retired RECs are summarized by in state, other PJM state and non PJM state, and carbon producing RECs and carbon free RECs. For example, Virginia met its 2024 RPS target using 4.9 percent carbon free RECs from Virginia, 81.7 percent carbon free RECs from other PJM states and 13.5 percent carbon producing RECs from Virginia and other PJM states. Ohio met its 2024 RPS target using 1.0 percent carbon free RECs from Ohio, 48.7 percent carbon free RECs from other PJM states, 15.5 percent carbon free RECs from non PJM states, 17.2 percent carbon producing RECs from Ohio and 17.6 percent carbon producing RECs from other PJM states. Illinois met its 2024 RPS target using 80.3 percent carbon free RECs from Illinois and 19.7 percent carbon free RECs from other PJM states. Illinois met its RPS target using 100.0 percent carbon free RECs for the 2019 through 2025 compliance years.

181 Retired REC information obtained through PJM GATS <https://gats.pjm-eis.com/gats2/PublicReports/RPSRetiredCertificatesReportingYear>. The timing of the REC retirement reports varies by state and the 2025 reporting year data may be incomplete for some states.

Figure 8-4 State fulfillment of Tier I equivalent RPS: 2021 through 2025

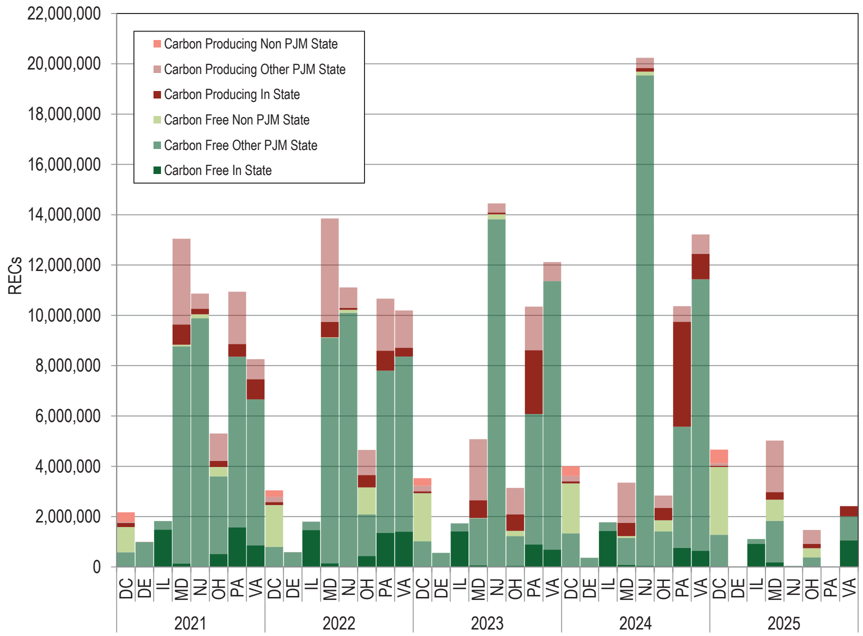


Table 8-17 State fulfillment of Tier I equivalent RPS: 2021 through 2025

		Carbon Free REC				Carbon Producing REC			
Year	REC Type	In State	Other PJM State	Non PJM State	Total	In State	Other PJM State	Non PJM State	Total
2021	DE New Eligible	0.3%	99.0%	0.0%	99.3%	0.7%	0.0%	0.0%	0.7%
	DC Tier I	0.0%	27.0%	45.9%	72.9%	7.4%	1.7%	17.9%	27.1%
	IL Renewable	81.0%	19.0%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%
	MD Tier I	1.0%	66.2%	0.5%	67.7%	6.1%	26.1%	0.0%	32.3%
	NJ Class I	0.1%	91.0%	1.4%	92.4%	2.0%	5.5%	0.0%	7.6%
	OH Renewable Energy Source	9.6%	58.3%	7.0%	74.9%	4.4%	20.7%	0.0%	25.1%
	PA Tier I	14.4%	62.0%	0.0%	76.4%	4.6%	19.1%	0.0%	23.6%
	VA Renewable	10.3%	70.4%	0.0%	80.7%	9.7%	9.6%	0.0%	19.3%
2022	DE New Eligible	0.9%	99.1%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%
	DC Tier I	0.0%	26.0%	54.8%	80.8%	3.7%	6.8%	8.7%	19.2%
	IL Renewable	81.3%	18.7%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%
	MD Tier I	1.0%	64.7%	0.2%	65.9%	4.4%	29.7%	0.0%	34.1%
	NJ Class I	0.2%	90.7%	1.0%	92.0%	0.7%	7.4%	0.0%	8.0%
	OH Renewable Energy Source	9.3%	35.6%	23.0%	67.9%	10.5%	21.6%	0.0%	32.1%
	PA Tier I	12.7%	60.4%	0.0%	73.1%	7.4%	19.4%	0.0%	26.9%
	VA Renewable	13.8%	68.3%	0.0%	82.1%	3.4%	14.6%	0.0%	17.9%
2023	DE New Eligible	0.9%	99.1%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%
	DC Tier I	0.0%	29.1%	53.9%	83.0%	2.2%	6.4%	8.5%	17.0%
	IL Renewable	81.6%	18.4%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%
	MD Tier I	1.2%	36.9%	0.2%	38.3%	13.9%	47.8%	0.0%	61.7%
	NJ Class I	0.1%	95.5%	1.4%	97.0%	0.5%	2.5%	0.0%	3.0%
	OH Renewable Energy Source	1.4%	37.5%	6.8%	45.7%	20.8%	33.5%	0.0%	54.3%
	PA Tier I	8.6%	50.2%	0.0%	58.8%	24.5%	16.8%	0.0%	41.2%
	VA Renewable	5.7%	88.0%	0.0%	93.7%	0.0%	6.3%	0.0%	6.3%
2024	DE New Eligible	0.0%	100.0%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%
	DC Tier I	0.0%	33.3%	49.7%	82.9%	2.0%	5.4%	9.7%	17.1%
	IL Renewable	80.3%	19.7%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%
	MD Tier I	2.3%	32.3%	1.9%	36.5%	15.7%	47.8%	0.0%	63.5%
	NJ Class I	0.2%	96.3%	0.8%	97.3%	0.7%	2.0%	0.0%	2.7%
	OH Renewable Energy Source	1.0%	48.7%	15.5%	65.3%	17.2%	17.6%	0.0%	34.7%
	PA Tier I	7.3%	46.5%	0.0%	53.8%	40.2%	6.0%	0.0%	46.2%
	VA Renewable	4.9%	81.7%	0.0%	86.5%	7.6%	5.9%	0.0%	13.5%
2025	DE New Eligible								
	DC Tier I	0.0%	27.4%	57.8%	85.2%	0.9%	2.2%	11.6%	14.8%
	IL Renewable	83.0%	17.0%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%
	MD Tier I	3.6%	32.8%	16.7%	53.1%	6.0%	40.9%	0.0%	46.9%
	NJ Class I	0.0%	100.0%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%
	OH Renewable Energy Source	0.5%	25.3%	24.6%	50.4%	11.8%	37.8%	0.0%	49.6%
	PA Tier I	100.0%	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%
	VA Renewable	43.6%	39.6%	0.0%	83.3%	16.7%	0.0%	0.0%	16.7%

Table 8-18 shows the percent of retail electric load that must be served by Tier II or a specific type of resource under each PJM jurisdiction's RPS by year. Tier II resources are generally not renewable resources. Table 8-18 also shows specific technology requirements that PJM jurisdictions have added to their renewable portfolio standards. The standards shown in Table 8-18 are included in the total RPS requirements presented in Table 8-14. Maryland, New Jersey and Pennsylvania have Tier II or Class II standards, which allow specific nonrenewable technology types, such as waste coal units located in Pennsylvania, to qualify for renewable energy credits. Washington, DC previously had Tier II standards. The Washington, DC tier II standard was discontinued at the end of the 2019 compliance year. By 2024, North Carolina's RPS requires that 0.2 percent of power be generated using swine waste and that 900 GWh of power be produced by poultry waste in 2020. Maryland established a minimum standard for offshore wind in 2017 that took effect in 2021 with an original requirement that 1.37 percent of load be served by offshore wind.[182] The standard has been revised to 0.14 percent for 2024.[183] The offshore wind requirement is only applicable if the Maryland offshore wind projects are producing RECs. [184]

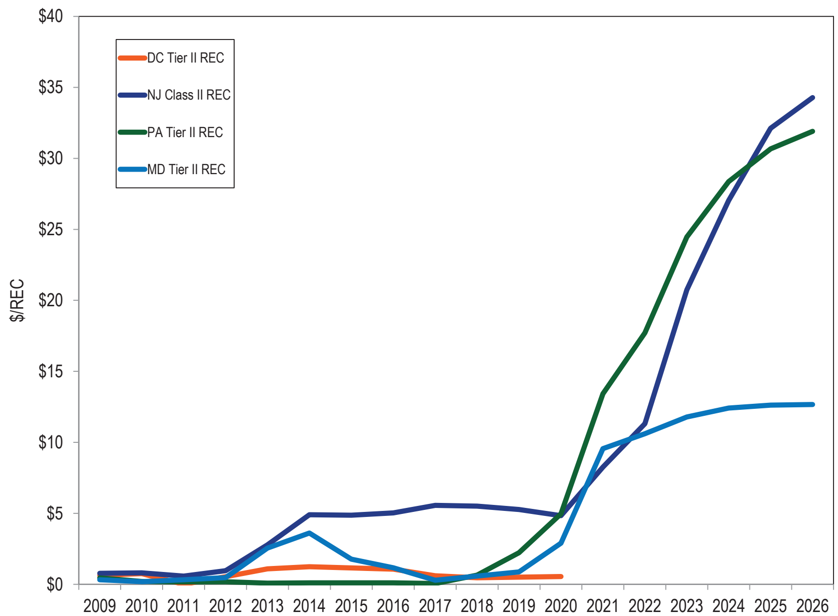
Table 8-18 Additional renewable standards of PJM jurisdictions: 2025 to 2035[185]

Jurisdiction	Type of Standard	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Maryland	Off Shore Wind	1.66%	2.61%	13.02%	13.02%	13.02%	13.02%	13.02%	13.02%	13.02%	13.02%	13.02%
Maryland	Geothermal	0.25%	0.50%	0.75%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
Maryland	Tier 2	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
New Jersey	Class II	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%			
North Carolina	Swine Waste	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
North Carolina	Poultry Waste (GWh)	900	900	900	900	900	900	900	900	900	900	900
Pennsylvania	Tier II	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%

182 Public Service Commission of Maryland, Offshore Wind Projects, Order No. 88192 (May 11, 2017) at 8, Table 2 <https://www.psc.state.md.us/wp-content/uploads/Order-No.-88192-Case-No.-9431-Offshore-Wind.pdf>.
183 See *Renewable Energy Portfolio Standard Report* at 5, Maryland Public Service Commissions (November 2023) <https://www.psc.state.md.us/wp-content/uploads/CY22-RPS-Annual-Report_Final-w-Corrected-Appdx-A.pdf>.
184 Id. at footnote 13.
185 New Jersey Administrative Code, Section 14:8-2.3 does not specify standards beyond compliance year 2032/2033.

Figure 8-5 shows the annual average Tier II REC price by jurisdiction for 2009 through March 2026. Tier II prices have been lower than Tier I REC prices in the past, but in recent years Pennsylvania and New Jersey Tier II REC prices are higher than their corresponding Tier I REC prices. Maryland, New Jersey and Pennsylvania are the only states with a Tier II standard in 2025.[186] The average Pennsylvania Tier II REC price in the first three months of 2026 was $31.90, 4.0 percent higher than the average price for 2025. The average New Jersey Class II REC price in the first three months of 2026 was $34.28, 6.7 percent higher than the average price for 2025. The average Maryland Tier II REC price in the first three months of 2026 was $12.66, 0.3 percent higher than the average price in 2025.[187]

Figure 8-5 Average Tier II REC price by jurisdiction: 2009 through March 2026



186 The District of Columbia dropped Tier II RECs from their RPS in 2021.
187 Tier II REC price information obtained through Evolution Markets, Inc.

Some PJM jurisdictions have specific solar resource RPS requirements. These solar requirements are included in the total requirements shown in Table 8-14 and Table 8-16 but must be met by solar RECs (SRECs). Table 8-19 shows the percent of retail electric load that must be served by solar energy resources under each PJM jurisdiction's RPS by year. Delaware, Illinois, Maryland, New Jersey, North Carolina, Pennsylvania, and Washington, DC have requirements for the proportion of load to be served by solar. The Illinois RPS specifies the number of RECs that must be sourced from photovoltaic resources energized after June 1, 2017. Recent legislation increased the SREC requirement from 2,000,000 RECs to 5,500,000 RECs beginning with the 2021/2022 Delivery Year.[188] New Jersey closed registration for new SRECs on April 30, 2020, having met its milestone that solar power equal or exceed 5.1 percent of New Jersey electricity sales.[189] On December 6, 2019, the New Jersey Board of Public Utilities announced a transitional program for solar generators not eligible for New Jersey SRECs.[190] The new program establishes a 15 year fixed priced Transition REC (TREC). On July 28, 2021, New Jersey Board of Public Utilities approved the Successor Solar Incentive (SuSI) Program which will provide incentives for 3,750 MW of new solar generation by 2026.[191] Pennsylvania allows only solar photovoltaic resources to fulfill their solar requirements. Solar thermal units like solar hot water heaters that do not generate electricity are Tier I resources in Pennsylvania. Ohio, Michigan and Virginia have no specific solar standards. The New Jersey legislature in May 2018 increased the solar standard from 3.2 percent to 4.3 percent for 2018, 5.1 percent for 2020 through 2022 and the solar standard decreases to 1.1 percent for 2032.[192] Maryland legislation in 2019 increased the solar carve out percentages from 2.5 percent to 14.5 percent in 2030. Ohio HB 6 removed the

188 See amendments to Sec. 1-75(c)(1)(C) of the Illinois Power Agency Act contained in Section 90-30 of Public Act 102-0662.
189 See Clean Energy Act of 2019 (NJ AB-2723); N.J.A.C. 14:82.4(b)6; BPU, Monthly Report on Status toward Attainment of the 5.1 percent Milestone for Closure of the SREC Program (March 31, 2020).
190 "New Jersey Board of Public Utilities Approves Solar Transition Program, Initiates a Cost Cap Proceeding," New Jersey Board of Public Utilities Press Release (December 6, 2019) <https://www.bpu.state.nj.us/bpu/newsroom/2019/approved/20191206.html>.
191 "NJBPU Approves 3,750 MW Successor Solar Incentive Program", New Jersey Board of Public Utilities Press Release (July 28, 2021) <https://www.nj.gov/bpu/newsroom/2021/approved/20210728.html>.
192 "Assembly, No. 3723," State of New Jersey, 218th Legislature (March 22, 2018), <http://www.njleg.state.nj.us/2018/Bills/A4000/3723_I1.PDF>.

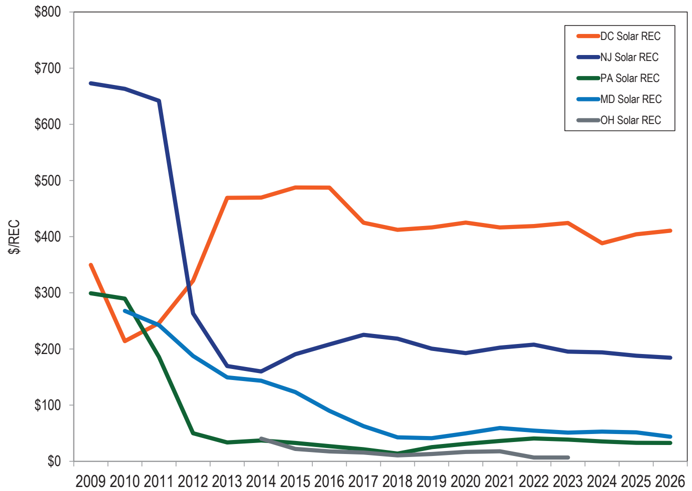
solar carve out from the Ohio RPS.[193] The Delaware General Assembly passed new RPS legislation on February 10, 2021, that increased the solar carve out target from 3.5 percent in 2025 to 10.0 percent in 2035.[194]

Table 8-19 Solar renewable standards by percent of electric load for PJM jurisdictions: 2025 to 2035[195] [196]

Jurisdiction with RPS	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Delaware	3.50%	3.75%	4.00%	4.25%	4.50%	5.00%	5.80%	6.60%	7.40%	8.40%	10.00%
Illinois (GWh)	5,500	5,500	5,500	5,500	5,500	24,750	24,750	24,750	24,750	24,750	24,750
Maryland	7.00%	8.00%	9.50%	11.00%	12.50%	14.50%	14.50%	14.50%	14.50%	14.50%	14.50%
New Jersey	4.50%	4.35%	3.74%	3.07%	2.21%	1.58%	1.40%	1.10%			
North Carolina	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
Pennsylvania	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
Washington, DC	3.45%	3.75%	4.10%	4.50%	4.75%	5.00%	5.25%	5.50%	6.00%	6.50%	7.00%

Figure 8-6 shows the annual average solar REC (SREC) price by jurisdiction for 2009 through March 2026. The average NJ SREC price was $184.51 in the first three months of 2026. The limited supply of solar facilities in Washington, DC compared to the RPS requirement results in higher SREC prices. The average Washington, DC SREC price was $410.72 in the first three months of 2026, a 1.6 percent increase compared to the average DC SREC price in 2025.[197]

Figure 8-6 Average SREC price by jurisdiction: 2009 through March 2026



193 Ohio Legislature House, 133rd Assembly, Bill No. 6, "Ohio Clean Air Program," effective Date October 22, 2019, <https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA133-HB-6>.
194 See Senate Bill 33, Delaware General Assembly (February 10, 2021) <https://legis.delaware.gov/BillDetail?legislationId=48278>.
195 The Illinois solar standard currently requires 5.5 million RECs from solar photovoltaic projects energized after June 1, 2017. Illinois Public Act 102-0662, September 15, 2021.
196 New Jersey Administrative Code, Section 14:8-2.3 does not specify standards beyond compliance year 2032/2033.
197 Solar REC average price information obtained through Evolution Markets, Inc. <http://www.evomarkets.com>.

Figure 8-7 and Table 8-20 show where the SRECs originated that are used to satisfy the states' solar requirement for 2021 through 2025.[198] Depending on the state, the solar RPS requirement can be fulfilled by in state or out of state SRECs. The SRECs purchased in some states are imported from other PJM states and from non PJM states. Table 8-20 shows the percent of local SRECs, SRECs from other PJM states and SRECs from non PJM states used to meet the RPS requirements. Since 2020, all SRECs used for RPS compliance in Illinois, Maryland, Pennsylvania and New Jersey have been sourced from in state solar generators.

Figure 8-7 State fulfillment of Solar RPS: 2021 through 2025

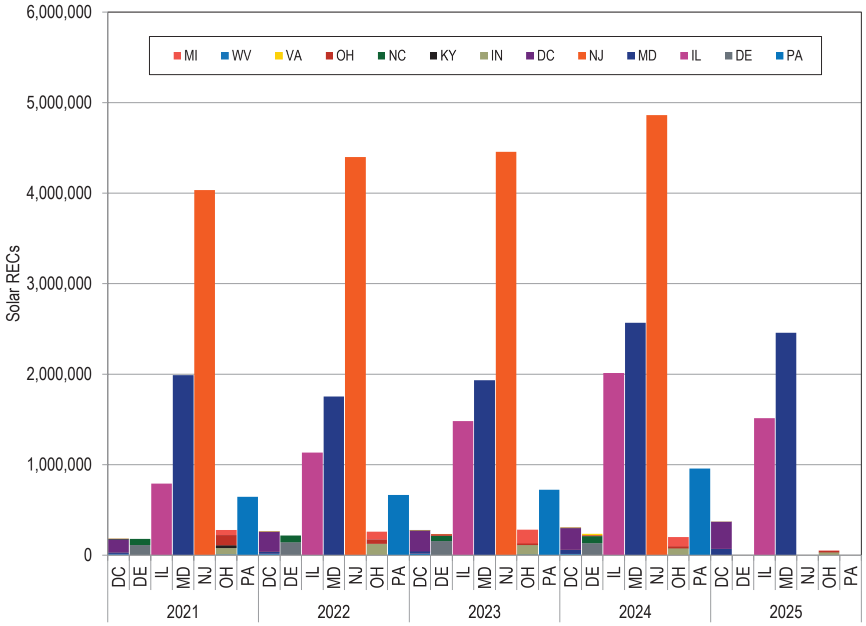


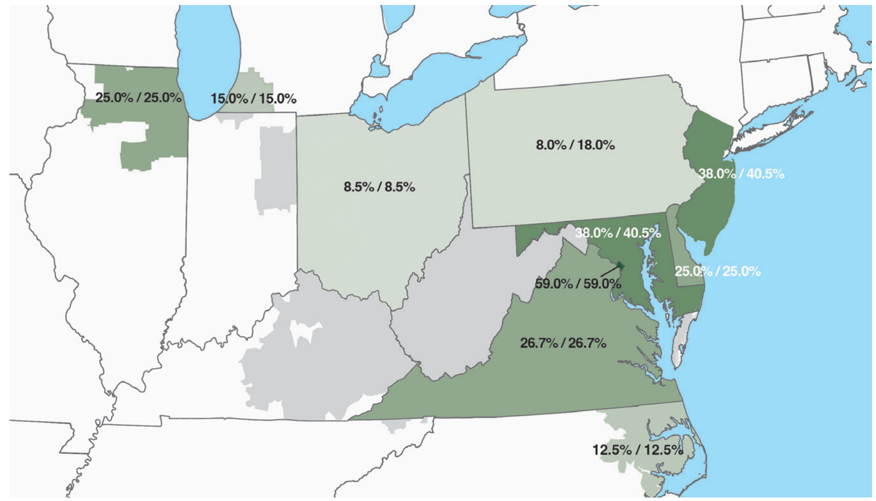
Table 8-20 State fulfillment of Solar RPS: 2021 through 2025

		In State	Other PJM State	Non PJM State
2021	DC Solar	78.0%	21.6%	0.3%
	DE Solar Eligible	62.3%	37.7%	0.0%
	IL Solar Renewable	100.0%	0.0%	0.0%
	MD Solar	100.0%	0.0%	0.0%
	NJ Solar	100.0%	0.0%	0.0%
	OH Solar Renewable Energy Source	40.2%	59.8%	0.0%
	PA Solar	100.0%	0.0%	0.0%
2022	DC Solar	81.9%	17.9%	0.2%
	DE Solar Eligible	65.8%	34.2%	0.0%
	IL Solar Renewable	100.0%	0.0%	0.0%
	MD Solar	100.0%	0.0%	0.0%
	NJ Solar	100.0%	0.0%	0.0%
	OH Solar Renewable Energy Source	17.3%	82.7%	0.0%
	PA Solar	100.0%	0.0%	0.0%
2023	DC Solar	82.2%	17.6%	0.3%
	DE Solar Eligible	67.0%	33.0%	0.0%
	IL Solar Renewable	100.0%	0.0%	0.0%
	MD Solar	100.0%	0.0%	0.0%
	NJ Solar	100.0%	0.0%	0.0%
	OH Solar Renewable Energy Source	6.2%	93.8%	0.0%
	PA Solar	100.0%	0.0%	0.0%
2024	DC Solar	78.0%	21.8%	0.2%
	DE Solar Eligible	56.5%	43.5%	0.0%
	IL Solar Renewable	100.0%	0.0%	0.0%
	MD Solar	100.0%	0.0%	0.0%
	NJ Solar	100.0%	0.0%	0.0%
	OH Solar Renewable Energy Source	10.7%	89.3%	0.0%
	PA Solar	100.0%	0.0%	0.0%
2025	DC Solar	80.9%	19.0%	0.1%
	DE Solar Eligible			
	IL Solar Renewable	100.0%	0.0%	0.0%
	MD Solar	100.0%	0.0%	0.0%
	NJ Solar			
	OH Solar Renewable Energy Source	34.3%	65.7%	0.0%
	PA Solar			

198 Retired REC information obtained through PJM GATS <https://gats.pjm-eis.com/gats2/PublicReports/RPSRetiredCertificatesReportingYear> (Accessed April 1, 2026). The timing of the REC retirement reports varies by state and the 2025 reporting year data is incomplete for some states.

Figure 8-8 shows the percent of retail electric load that must be served by Tier I resources and Tier 2 resources in each PJM jurisdiction with a mandatory RPS. For each state in Figure 8-8, the first number represents the RPS percent for Tier I where defined, or renewable energy resources where tiers are not defined; the second number represents the RPS percent for all eligible technologies which includes both renewable and alternative energy resources. States with higher percent requirements for renewable energy resources are shaded darker. Jurisdictions with no standards or with only voluntary RPS are shaded gray. Pennsylvania's RPS illustrates the need to differentiate between percent requirements for renewable and alternative energy resources. The Pennsylvania RPS identifies solar photovoltaic, solar thermal, wind, geothermal, biomass, and low-impact hydropower as Tier I resources. The Pennsylvania RPS identifies waste coal, demand side management, large-scale hydropower, integrated gasification combined cycle, clean coal and municipal solid waste as eligible Tier II resources. As a result, the 18.0 percent number in Figure 8-8 overstates the percent of retail electric load in Pennsylvania that must be served by renewable energy resources. The 8.0 percent number in Figure 8-8 is a more accurate measure of the percent of retail electric load in Pennsylvania that must be served by renewable energy resources.

Figure 8-8 Map of retail electric load shares under RPS – Renewable / Alternative Energy resources: January through March, 2026[199]



Under the existing state renewable portfolio standards, 20.7 percent of PJM load should have been served by Tier I and Tier II renewable and alternative energy resources in the first three months of 2026. Tier I resources include landfill gas, run of river hydro, wind and solar resources. Tier II resources include pumped storage, large scale hydro, solid waste and waste coal resources. In the first three months of 2026, only 10.3 percent of PJM generation was produced by renewable and alternative energy resources, including carbon producing and noncarbon producing Tier I and Tier II generation as shown in Table 8-21. If the proportion of load among states remains constant, 25.5 percent of PJM load must be served by Tier I and Tier II renewable and alternative energy resources in 2030 under currently defined RPS rules.

Approximately 18.4 percent of PJM load should have been served by Tier I or renewable energy resources in the first three months of 2026. In the first three months of 2026, only 8.4 percent of PJM generation was Tier I or renewable

199 The standards in this chart include the Tier I standards used by some states in the PJM footprint, as well as the total alternative energy standard for states that do not classify eligible technologies into tiers.

energy. If the proportion of load among states remains constant, 23.2 percent of PJM load must be served by Tier I or renewable energy resources in 2030 under defined RPS rules.

The current REC production from PJM generation resources was not enough to meet the state renewable requirements in the first three months of 2026, and LSEs purchased RECs from non PJM resources (e.g. behind the meter rooftop solar) and RECs from resources outside the PJM footprint (Table 8-22). In jurisdictions with an RPS, load serving entities must either generate power from eligible technologies identified in each jurisdiction's RPS, purchase RECs from resources classified as eligible technologies or make alternative compliance payments for unmet goals based on each state's requirements. Table 8-21 shows generation by jurisdiction and resource type in the first three months of 2026. Wind generation accounted for 10,725.6 GWh of the 19,005.2 Tier I GWh, or 56.4 percent. As shown in Table 8-21, 23,357.2 GWh were generated by Tier I and Tier II resources, of which Tier I resources accounted for 81.4 percent. Wind and solar generation (noncarbon producing) was 7.1 percent of total generation in PJM in the first three months of 2026. Tier I generation was 8.4 percent of total generation in PJM and Tier II was 1.9 percent of total generation in PJM in the first three months of 2026. Biofuel, landfill gas, pumped storage hydro, solid waste and waste coal (carbon producing) accounted for 4,651.4 GWh, or 19.9 percent of the total Tier I and Tier II generation.

Table 8-21 Tier I and Tier II generation by jurisdiction and renewable resource type (GWh): January through March, 2026

	Tier I									Tier II					
Jurisdiction	Biofuel	Landfill Gas	Run of River	Pumped-Storage Hydro	Other Hydro	Solar	Solid Waste	Wind	Total Tier I Credit	Pumped-Storage Hydro	Other Hydro	Solid Waste	Waste Coal	Total Tier II Credit	Total Credit GWh
Delaware	0.0	10.0	0.0	0.0	0.0	19.2	0.0	0.0	29.2	0.0	0.0	0.0	0.0	0.0	29.2
Illinois	0.0	11.8	0.0	0.0	0.0	35.1	0.0	5,251.1	5,298.0	0.0	0.0	0.0	0.0	0.0	5,298.0
Indiana	0.0	3.1	0.0	0.0	9.2	502.5	0.0	2,231.4	2,746.3	0.0	0.0	0.0	0.0	0.0	2,746.3
Kentucky	0.0	0.0	51.5	0.0	20.2	124.7	0.0	0.0	196.4	0.0	0.0	0.0	0.0	0.0	196.4
Maryland	0.0	8.0	0.0	0.0	0.0	288.2	255.5	326.9	878.6	0.0	0.0	0.0	0.0	0.0	878.6
Michigan	0.0	12.6	0.0	0.0	15.6	0.9	0.0	0.0	29.2	0.0	0.0	0.0	0.0	0.0	29.2
New Jersey	0.0	7.6	0.0	0.0	0.0	158.7	0.0	3.5	169.7	115.2	0.0	312.1	0.0	427.2	596.9
North Carolina	0.0	0.0	46.0	0.0	0.0	589.3	0.0	276.7	912.0	0.0	0.0	0.0	0.0	0.0	912.0
Ohio	0.0	19.8	236.3	0.0	0.0	1,648.0	0.0	917.7	2,821.7	0.0	0.0	0.0	0.0	0.0	2,821.7
Pennsylvania	52.9	42.3	1,231.1	0.0	6.4	344.9	0.0	1,222.1	2,899.7	792.5	0.0	308.8	1,789.0	2,890.3	5,790.0
Tennessee	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
Virginia	299.3	97.6	113.8	86.3	11.1	1,636.2	0.0	16.9	2,261.1	583.1	357.3	0.0	0.0	940.4	3,201.5
Washington, D.C.	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
West Virginia	0.0	5.2	236.0	0.0	0.0	42.6	0.0	479.5	763.3	0.0	0.0	0.0	94.1	94.1	857.5
Total	352.2	218.1	1,914.7	86.3	62.5	5,390.2	255.5	10,725.6	19,005.2	1,490.8	357.3	620.9	1,883.2	4,352.1	23,357.2

PJM states with RPS rely heavily on imports and generation from behind the meter resources for RPS compliance. In the first three months of 2026, Tier I generation in PJM met only 48.5 percent of the Tier I RPS requirements. Table 8-22 compares each state's RPS requirement in the first three months of 2026 with generation by RPS eligible PJM generators. Illinois had sufficient in state generation to cover 93.2 percent of the RPS requirement and Pennsylvania generation was sufficient to cover 90.3 percent of the Tier I RPS requirement and 72.0 percent of the Tier II RPS requirement. North Carolina generation was 5.5 times higher than the RPS requirement in 2025; but a relatively small portion of the North Carolina load is in PJM. Overall there was sufficient generation by PJM generators to meet 48.5 percent of the Tier I RPS requirement and 88.9 percent of the Tier II RPS requirement in the first three months of 2026. RPS compliance reports indicate that almost all of the RPS requirement is met with the purchase or acquisition of RECs, with only a very small amount of the requirement fulfilled through alternative compliance payments. A large portion of the Tier I RPS requirement is satisfied by behind the meter generation in the PJM states and to a lesser extent, through the purchase of RECs from non PJM states.

Table 8-22 RPS Requirements and Generation by RPS Eligible Resources: January through March, 2026

	Tier I			Tier II		
Jurisdiction	PJM Generation (GWh)	RPS Requirement (GWh)	Generation as Percent of RPS Requirement	PJM Generation (GWh)	RPS Requirement (GWh)	Generation as Percent of RPS Requirement
Delaware	29.2	828.1	3.5%	0.0	0.0	
Illinois	5,298.0	5,685.2	93.2%	0.0	0.0	
Indiana	2,746.3	0.0		0.0	0.0	
Kentucky	196.4	0.0		0.0	0.0	
Maryland	878.6	6,327.1	13.9%	0.0	416.3	0.0%
Michigan	29.2	164.7	17.7%	0.0	0.0	
New Jersey	169.7	7,094.0	2.4%	427.2	466.7	91.5%
North Carolina	912.0	161.1	566.1%	0.0	0.0	
Ohio	2,821.7	3,693.8	76.4%	0.0	0.0	
Pennsylvania	2,899.7	3,211.2	90.3%	2,890.3	4,014.0	72.0%
Tennessee	0.0	0.0		0.0	0.0	
Virginia	2,261.1	10,554.0	21.4%	940.4	0.0	
Washington, D.C.	0.0	1,498.6	0.0%	0.0	0.0	
West Virginia	763.3	0.0		94.1	0.0	
Total	19,005.2	39,217.8	48.5%	4,352.1	4,897.0	88.9%

Table 8-23 shows the summer installed capacity rating of Tier I and Tier II wholesale capacity resources in PJM by jurisdiction, as defined by primary fuel type. This capacity includes coal, natural gas and oil units that qualify as Tier II because they have a secondary fuel capability that satisfies the alternative energy standards of a PJM state or jurisdiction. For example, a coal generator that can also burn biofuel to generate power could list the alternative fuel as biofuel. A REC is only generated when the unit is operating using the fuel listed as Tier I or Tier II. Ohio has the largest amount of solar capacity in PJM, 5,494.4 MW, or 27.2 percent of the total solar capacity. Wind resources located in Illinois, Indiana and Ohio account for 8,735.8 MW, or 73.2 percent of the total wind capacity.

Table 8-23 Renewable capacity by jurisdiction (MW): April 1, 2026[200]

Jurisdiction	Biofuel	Coal / Biofuel	Hydro	Landfill Gas	Natural Gas / CMG	Natural Gas / Landfill Gas	Oil / Biofuel	Oil / Landfill Gas	Pumped-Storage Hydro	Solar	Solid Waste	Waste Coal	Waste Heat	Wind	Total
Delaware	0.0	0.0	0.0	8.1	0.0	1,797.0	0.0	13.0	0.0	50.0	0.0	0.0	0.0	0.0	1,868.1
Illinois	0.0	0.0	0.0	15.0	0.0	0.0	0.0	0.0	0.0	136.3	0.0	0.0	0.0	5,339.7	5,491.0
Indiana	0.0	0.0	8.2	3.2	0.0	0.0	0.0	0.0	0.0	1,780.4	0.0	0.0	0.0	2,350.5	4,142.2
Kentucky	0.0	0.0	132.7	0.0	0.0	0.0	0.0	0.0	0.0	425.6	0.0	0.0	0.0	0.0	558.3
Maryland	0.0	0.0	0.0	19.9	0.0	0.0	69.0	0.0	0.0	1,041.0	191.2	0.0	0.0	298.6	1,619.7
Michigan	0.0	0.0	13.9	12.0	0.0	0.0	0.0	0.0	0.0	4.6	0.0	0.0	0.0	0.0	30.5
Missouri	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	146.0	146.0
New Jersey	0.0	0.0	11.0	19.5	0.0	0.0	0.0	0.0	453.0	809.6	204.6	0.0	0.0	4.5	1,502.1
North Carolina	0.0	0.0	325.0	0.0	0.0	0.0	0.0	0.0	0.0	1,854.7	0.0	0.0	0.0	397.0	2,576.7
Ohio	0.0	1,020.0	194.4	14.4	0.0	0.0	136.0	0.0	0.0	5,494.4	0.0	0.0	134.0	1,045.6	8,038.7
Pennsylvania	54.0	0.0	1,387.3	111.0	1,105.0	1,300.0	0.0	0.0	1,269.0	1,385.0	209.3	1,347.0	0.0	1,545.2	9,712.8
Tennessee	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
Virginia	202.9	585.0	436.4	115.7	0.0	0.0	0.0	0.0	5,386.0	4,906.2	0.0	0.0	0.0	12.0	11,644.1
Washington, D.C.	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
West Virginia	0.0	0.0	209.9	8.0	0.0	0.0	0.0	0.0	0.0	155.4	0.0	96.0	0.0	802.3	1,271.5
PJM Total	256.9	1,605.0	2,718.7	326.7	1,105.0	3,097.0	205.0	13.0	7,108.0	18,043.1	605.0	1,443.0	134.0	11,941.4	48,601.8

Table **8-24** shows non PJM renewable capacity registered in the PJM generation attribute tracking system (GATS).[201] These resources are not PJM wholesale market resources even though most are located in PJM states. For example, roof top solar panels within the PJM footprint generate SRECs but are not PJM wholesale market units. These nonwholesale resources include solar capacity of 15,236.1 MW of which 4,216.8 MW are in New Jersey. These nonwholesale resources can earn renewable energy credits, and can be used to fulfill the renewable portfolio standards in PJM jurisdictions. There are also 3,006.0 MW of GATS capacity located in jurisdictions outside PJM that are eligible to sell RECs in at least one PJM jurisdiction.

200 "Renewable Generators Registered in GATS", PJM EIS <https://www.pjm-eis.com/reports-and-events/public-reports>. Capacity in ICAP.

201 PJM Environmental Information Services (EIS), an unregulated subsidiary of PJM, operates the generation attribute tracking system (GATS), which is used by many jurisdictions to track these renewable energy credits. GATS publishes details on every renewable generator registered within the PJM footprint and aggregate emissions of renewable generation, but does not publish generation data by unit and does not make unit data available to the MMU.

Table 8-24 Renewable capacity by jurisdiction, non-PJM units registered in GATS (MW): April 1, 2026[202]

Jurisdiction	Biofuel	Coal / Biofuel	Fuel Cell	Geothermal	Hydro	Landfill Gas	Natural Gas / Distributed Generation	Other Gas	Solar	Solid Waste	Waste Coal	Waste Heat	Wind	Total
Alabama	54.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	54.0
Delaware	0.0	0.0	0.0	0.0	0.0	4.2	0.0	0.0	214.7	0.0	0.0	0.0	2.0	220.9
Georgia	0.0	0.0	0.0	0.0	0.0	27.1	0.0	0.0	152.2	0.0	0.0	0.0	0.0	179.3
Illinois	0.0	0.0	0.0	1.0	20.0	43.8	0.0	2.9	2,880.2	0.0	0.0	0.0	699.2	3,647.1
Indiana	0.0	0.0	0.0	0.0	53.7	44.0	0.0	0.0	490.3	0.0	0.0	184.6	180.0	952.7
Iowa	0.0	0.0	0.0	0.0	0.0	1.6	0.0	0.0	2.1	0.0	0.0	0.0	466.6	470.3
Kentucky	93.0	600.0	0.0	0.0	167.9	21.0	0.0	0.0	44.8	0.0	0.0	0.0	0.0	926.6
Maryland	18.5	0.0	0.6	106.4	0.0	4.0	0.0	0.0	2,020.7	10.0	0.0	0.0	0.3	2,160.5
Michigan	31.0	0.0	0.0	0.0	17.2	5.6	0.0	0.0	107.4	0.0	0.0	0.0	1.8	163.0
Minnesota	0.0	0.0	0.0	0.0	36.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,102.0	1,138.0
Missouri	0.0	0.0	0.0	0.0	0.0	5.6	0.0	0.0	61.2	0.0	0.0	0.0	693.0	759.8
New Jersey	0.0	0.0	2.4	0.0	0.0	9.5	0.0	15.4	4,216.8	0.0	0.0	0.0	3.1	4,247.2
North Carolina	151.5	0.0	0.0	0.0	430.4	0.0	0.0	0.0	1,307.5	0.0	0.0	0.0	0.0	1,889.4
North Dakota	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	360.0	360.0
Ohio	0.0	0.0	0.0	0.1	3.0	22.9	0.0	35.3	407.9	0.0	0.0	34.0	56.6	559.8
Pennsylvania	62.2	109.7	9.3	1.7	56.5	39.2	40.8	99.4	1,368.5	0.2	680.2	57.6	3.2	2,528.5
South Carolina	0.0	0.0	0.0	0.0	63.0	26.6	0.0	0.0	91.3	0.0	0.0	0.0	0.0	180.9
Tennessee	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
Virginia	287.6	0.0	0.0	0.5	30.8	4.8	0.0	1.3	1,459.9	20.0	0.0	121.3	0.0	1,926.2
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	49.4	312.9	0.0	0.0	28.5	0.0	390.8
West Virginia	0.0	0.0	0.0	0.0	102.0	0.0	0.0	0.0	97.8	0.0	0.0	0.0	0.0	199.9
Wisconsin	44.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	44.6
Total	742.3	709.7	12.3	109.9	980.4	259.9	40.8	203.7	15,236.1	30.2	680.2	426.0	3,567.8	22,999.2

The capacity values in Table 8-23 and Table 8-24 are installed capacity (ICAP) values. The unit of measurement for PJM's reliability standards and PJM capacity market auctions is unforced capacity (UCAP). PJM uses conversion factors to convert ICAP into UCAP and this process is known as capacity accreditation. Prior to the 2023/2024 Delivery Year, a generator's capacity value was derated from ICAP to UCAP by multiplying the generator's net maximum capability by a derating factor. The derating factors for solar and wind resources were based on either the generator's historical performance during summer peak hours or a class average value calculated by PJM. The intent of this approach was to obtain a MW value the generator can reliably produce during the summer peak hours.[203] An average ELCC method was used to determine the capacity values for intermittent and storage resources for the 2023/2024 Delivery Year and the 2024/2025 Delivery Year.[204] Beginning with the 2025/2026 Delivery Year, PJM uses a marginal ELCC method to determine capacity values for all resources. As of March 31, 2026, there are 4,549.9 MW of deliverable wind capacity.[205] This compares to 13,028.8 MW of nameplate wind capacity and 4,811.1 MW of derated wind capacity (UCAP). As of March 31, 2026, there are 8,586 MW of deliverable solar capacity. This compares to 16,502.5 MW of nameplate solar capacity and 2,190.7 MW of solar derated capacity (UCAP). Wind generators have higher derating factors during the winter months (November through April) because

202 See PJM-EIS (Environmental Information Services), Generation Attribute Tracking System, "Renewable Generators Registered in GATS," <https://gats.pjm-eis.com/gats2/PublicReports/RenewableGeneratorsRegisteredinGATS>.
203 See Appendix B in "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," <https://pjm.com/-/media/documents/manuals/m21.ashx>.
204 See Capacity Value of Intermittent Resources (ELCC) in *2024 Quarterly State of the Market Report for PJM: January through March*, Section 5: Capacity Market.
205 Deliverable capacity is the level of capacity injection rights (CIRs) held by the capacity resource.

PJM rules make winter capacity interconnection rights (CIRs) available. The deliverable wind capacity on September 30, 202,5 was 2,265.7 MW. The increase in the deliverable wind capacity from September 30, 2025, to March 31, 2026, is mostly the result of winter CIRs that are provided to wind without charge for the winter months. PJM's practice of giving away winter CIRs, that appear to be available because other resources paid for the supporting network upgrades, requires annual capacity resources to subsidize the interconnection costs of intermittent resources and artificially increases the capacity value of the winter resources. PJM should ensure that the winter capacity value of thermal resources is not inefficiently constrained by the failure to assign winter CIRs to thermal resources.

There were two pre ELCC classes of wind based on location with class average capacity factors of 14.7 percent and 17.6 percent. There were three pre ELCC classes of solar generators with capacity factors ranging from 38.0 percent to 60.0 percent.[206] For the 2023/2024 Delivery Year, the ELCC rating for solar generators with fixed panels was 50.0 percent, the ELCC rating for solar generators with tracking panels was 61.0 percent, and the ELCC rating for onshore wind generators was 15.0 percent.[207] For the 2024/2025 Delivery Year, the ELCC rating for solar generators with fixed panels was 33.0 percent, the ELCC rating for solar generators with tracking panels was 50.0 percent, and the ELCC rating for onshore wind generators was 21.0 percent. PJM implemented a new marginal ELCC approach for the 2025/2026 Delivery Year. For the 2025/2026 Delivery Year, the ELCC rating for solar generators with fixed panels is 10.0 percent, the ELCC rating for solar generators with tracking panels is 14.0 percent, and the ELCC rating for onshore wind generators is 38.0 percent. For the 2026/2027 Delivery Year, the ELCC rating for solar generators with fixed panels is 10.0 percent, the ELCC rating for solar generators with tracking panels is 13.0 percent, and the ELCC rating for onshore wind generators is 38.0 percent.[208]

Renewable energy credits are related to the production and purchase of wholesale power, but are not, when they constitute a transaction separate from a wholesale sale of power, subject to FERC regulation.[209] 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. Revenues from RECs markets are revenues for PJM resources earned in addition to revenues earned from the sale of the same MWh in PJM markets. RECs revenues are included in net revenues in unit offers in the capacity market and the treatment of RECs in unit cost-based offers is included in unit fuel cost policies.

Delaware, North Carolina, Michigan and Virginia allow various types of resources to earn multiple RECs per MWh, though typically one REC is equal to one MWh. For example, Delaware provided a three MWh REC for each MWh produced by in state customer sited photovoltaic generation and fuel cells using renewable fuels that are installed on or before December 31, 2014.[210] This is equivalent to providing a REC price equal to three times its stated value per MWh.

In addition to GATS, there are several other REC tracking systems used by states in the PJM footprint. Illinois, Indiana and Ohio use both GATS and M-RETS, the REC tracking system for resources located in the Midcontinent ISO, to track the sales of RECs used to fulfill their RPS requirements. Michigan and North Carolina have created their own state tracking systems, MIRECS and NC-RETS, through which all RECs used to satisfy these states' RPS requirements must ultimately be traded. Table 8-25 shows the REC tracking systems used by each state within the PJM footprint. To ensure a REC is only used one time, REC tracking systems must keep an account of a REC from its creation until its retirement. A REC is considered to be retired when it has been used to satisfy an obligation associated with an RPS.

206 Id.
207 *ELCC Class Ratings for 2023/2024 3IA, 2024/2026 BRA and 2026/2027 BRA*, PJM Interconnection, L.L.C. (January 6, 2023) <https://www.pjm.com/planning/resource-adequacy-planning/effective-load-carrying-capability>.
208 For additional information on ELCC ratings see the *2026 Annual State of the Market Report for PJM: January through March, Section 5, ELCC: The Capacity Value Resources.*
209 See *WSPP, Inc.*, 139 FERC ¶ 61,051 at P 18 (2012) ("we conclude that unbundled REC transactions fall outside of the Commission's jurisdiction under sections 201, 205 and 206 of the FPA. We further conclude that bundled REC transactions fall within the Commission's jurisdiction under sections 201, 205 and 206 of the FPA"); citing *American Ref-Fuel Company, et al.*, 105 FERC ¶ 61,004 at PP 23–24 (2003) ("American Ref-Fuel, 105 FERC ¶ 61,004 at PP 23-24 ("RECs are created by the States. They exist outside the confines of PURPA... And the contracts for sales of QF capacity and energy, entered into pursuant to PURPA, ... do not control the ownership of RECs."); see also *Williams Solar LLC and Allco Finance Limited*, 156 FERC ¶ 61,042 (2016).
210 Delaware Code, Title 26, Chapter 1, Subchapter III-A, Section 356(a).

Table 8-25 REC tracking systems in PJM states with renewable portfolio standards

Jurisdiction with RPS	REC Tracking System Used			
Delaware	PJM-GATS			
Illinois	PJM-GATS	M-RETS		
Maryland	PJM-GATS			
Michigan			MIRECS	
New Jersey	PJM-GATS			
North Carolina				NC-RETS
Ohio	PJM-GATS	M-RETS		
Pennsylvania	PJM-GATS			
Virginia	PJM-GATS			
Washington, D.C.	PJM-GATS			
Jurisdiction with Voluntary Standard				
Indiana	PJM-GATS	M-RETS		

All PJM states with renewable portfolio standards have established geographical restrictions governing the source of RECs to satisfy states' standards. Table 8-26 describes these restrictions. Indiana, Illinois, Michigan, and Ohio all have provisions in their renewables standards that require all or a portion of RECs used to comply with each state's standards to be generated by in state resources. Illinois recently relaxed the geographic restrictions to allow RECs sourced from wind or photovoltaic resources that are deliverable to Illinois or an adjacent state via high voltage direct current transmission. North Carolina has provisions that require RECs to be purchased from in state resources but Dominion, the only utility located in both North Carolina and PJM, is exempt from these provisions. Pennsylvania added a provision in 2017 that requires SRECs used to comply with Pennsylvania's solar photovoltaics carve out standard to be sourced from resources located in Pennsylvania.

In addition, Pennsylvania and Virginia require that RECs used for RPS compliance be produced from resources located within the PJM footprint. Delaware requires that RECs used for compliance with its RPS are produced from resources located within the PJM footprint or resources located elsewhere if these resources can demonstrate that the power they produce is directly deliverable to Delaware. The District of Columbia, Maryland and New Jersey allow RECs to be purchased from resources located within PJM in addition to large areas that adjoin PJM for compliance with their standards.

Table 8-26 Geographic restrictions on REC purchases for renewable portfolio standard compliance in PJM states

State with RPS	RPS Contains In-state Provision	Geographical Requirements for RPS Compliance
Delaware	No	RECs must be purchased from resources located either within PJM or from resources outside of PJM that are directly deliverable into Delaware.
Illinois	Yes	All RECs must be purchased from resources located within Illinois or from resources located in adjacent states that meet certain public interest criteria or from utility scale wind or photovoltaic resources that are deliverable to Illinois or an adjacent state via high voltage direct current transmission.
Maryland	No	RECs must come from within PJM, 10-30 miles offshore the coast of Maryland or from a control area adjacent to PJM that is capable of delivering power into PJM.
Michigan	Yes	RECs must either come from resources located within Michigan or anywhere in the service territory of retail electric provider in Michigan that is not an alternative electric supplier. There are many exceptions to these requirements (see Michigan S.B. 213).
New Jersey	No	RECs must either be purchased from resources located within PJM or from resources located outside of PJM for which the energy associated with the REC is delivered to PJM via dynamic scheduling.
North Carolina	Yes	Dominion, the only utility located in both the state of North Carolina and PJM, may purchase RECs from anywhere. Other utilities in North Carolina not located in PJM are subject to different REC requirements (see G.S. 62-113.8).
Ohio	Yes	All RECs must be generated from resources that are located in the state of Ohio or have the capability to deliver power directly into Ohio. Any renewable facility located in a state contiguous to Ohio has been deemed deliverable into the state of Ohio. For renewable resources in noncontiguous states, deliverabilty must be demonstarted to the Public Utilities Commission of Ohio.
Pennsylvania	Yes	RECs must be purchased from resources located within PJM. All SRECs used for compliance with the Solar PV standard must source from solar PV resources within the state of Pennsylvania.
Virginia	No	RECs must be purchased from resources located within PJM
Washington, D.C.	No	RECs must be purchased from either a PJM state or a state adjacent with PJM. A PJM state is defined as any state with a portion of their geographical boundary within the footprint of PJM. An adjacent state is defined as a state that lies next to a PJM state, i.e. SC, GA, AL, AR, IA, NY, MO, MS, and WI.

PJM jurisdictions have various methods for enforcing compliance with required renewable portfolio standards. If a retail supplier is unable to comply with the renewable portfolio standards required by the jurisdiction, suppliers may make alternative compliance payments (ACPs), with varying standards, to cover any shortfall between the RECs required by the state and those the retail supplier actually purchased. The ACPs, which are penalties, generally function as a cap on the market value of RECs, although in Pennsylvania the solar ACP is dependent upon the price of solar RECs retired during the year. In New Jersey, solar ACPs are currently $198 per MWh.[211] In Pennsylvania, the ACP for tier I and tier II RECs is $45 per MWh and the solar ACPs is 200 percent of the average credit price of Pennsylvania solar RECs sold during the reporting year plus the value of any solar rebates in other PJM states. The most recent ACP for Pennsylvania solar is $66.40.[212] Delaware recently reduced the solar ACP from $400 per credit to $150 per credit.[213] The Maryland solar ACP is $55 per credit in 2025. The Washington DC solar ACP was reduced from $480 per credit to $460 per credit for 2025.[214]

Figure 8-9 shows the historical relationship between SREC prices and ACP levels. The SREC price is represented by a solid line in the figure and the corresponding ACP level is represented by a dashed line. For each jurisdiction, the ACP is an upper bound for the price level. In Michigan and North Carolina, there are no defined values for ACPs. The public utility commissions in Michigan and North Carolina have discretionary power to assess what a load serving entity must pay for any RPS shortfalls.

Table 8-27 shows the alternative compliance standards for RPS in PJM jurisdictions.

Table 8-27 Tier I, Tier II, and Solar alternative compliance payments in PJM jurisdictions: January through March,2026[215] [216]

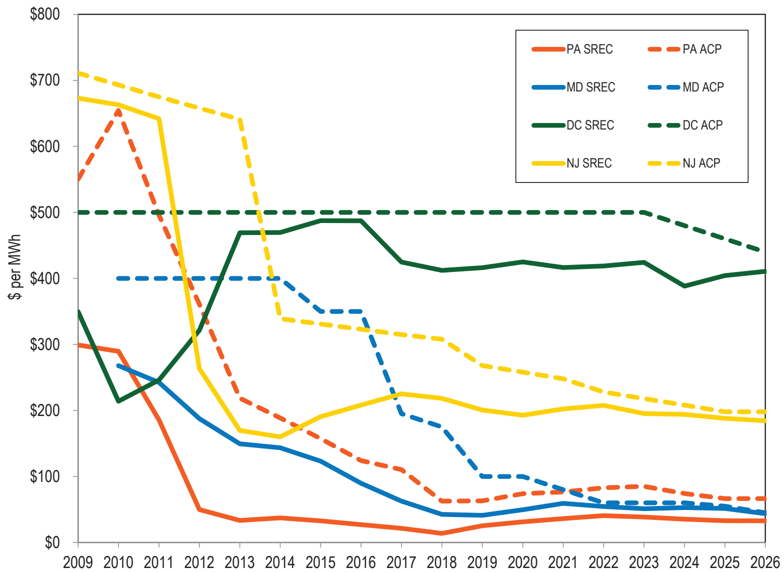
Jurisdiction with RPS	Standard Alternative Compliance ($/MWh)	Tier II Alternative Compliance ($/MWh)	Solar Alternative Compliance ($/MWh)
Delaware	$25.00		$150.00
Illinois	$0.35		
Maryland	$24.75	$15.00	$45.00
Michigan	No specific penalties		
New Jersey	$50.00	$50.00	$198.00
North Carolina	No specific penalties: At the discretion of the NC Utility Commission		
Ohio	$66.01		
Pennsylvania	$45.00	$45.00	$66.40
Washington, D.C.	$50.00	$10.00	$440.00
Jurisdiction with Voluntary Standard			
Indiana	Voluntary standard - No Penalties		
Jurisdiction with No Standard			
Kentucky	No standard		
Tennessee	No standard		
West Virginia	No standard		

Load serving entities participating in mandatory RPS programs in PJM jurisdictions must submit compliance reports to the relevant jurisdiction's public utility commission.

211 N.J. S. 2314/A. 3723.
212 See AEPS History Pricing report at the AEPS website <https://pennaeps.com/reports/> (Accessed May 2, 2025).
213 See Senate Bill 33, Delaware General Assembly (February 10, 2021) <https://legis.delaware.gov/BillDetail?legislationId=48278>.
214 DC Code: § 34-1434.

215 The Ohio standard alternative compliance payment (ACP) is updated annually <https://puco.ohio.gov/utilities/electricity/resources/acp-annual-adjustment-of-the-non-solar-alternative-compliance-payment>. The Illinois Commerce Commission periodically publishes updates to the effective ACP amount <https://www.icc.illinois.gov/electricity/RPSCompliancePaymentNotices.aspx>. For updated Maryland ACPs, see Table 3 of the 2024 Renewable Energy Portfolio Standard Report <https://www.psc.state.md.us/commission-reports/>.
216 The entry for Pennsylvania reflects the solar ACP for 2025. See "Pricing," <https://www.pennaeps.com/reports/> (Accessed April 1, 2026).

Figure 8-9 Comparison of SREC price and solar ACP: 2009 through March 2026



In their submitted compliance reports, load serving entities must indicate the quantity of MWh that they have generated using eligible renewable or alternative energy resources. They must also identify the quantity of RECs they may have purchased to make up for renewable energy generation shortfalls or to comply with RPS provisions requiring that they purchase RECs. The public utility commissions then release RPS compliance reports to the public.

The Pennsylvania Public Utility Commission issued the 2024/2025 compliance report for the Pennsylvania Alternative Energy Standards Act of 2004 in February 2026.[217] Pennsylvania reported that the 682,693 SRECs, 10,638,582 Tier I RECs and 24,975,510 Tier II RECs were retired during the 2024/2025 reporting year (June 1, 2024 through May 31, 2025). Supplier obligations for 61 SRECs, 873 Tier I RECs and 1,225 Tier II RECs required ACPs. The total cost for the 2024/2025 reporting year was $702.0 million, a 0.3 percent decrease from 2023/2024.

The Public Service Commission of the District of Columbia reported that 307,793 SRECs and 34,005,495 Tier I RECs were retired during the 2024 compliance year. The average price for solar RECs was $421. ACPs increased from $1.8 million for 2023 to $3.9 million for 2024.[218]

The Public Service Commission of Maryland reported that 63.9 percent of the 2024 REC obligation was satisfied by ACPs.[219] The report notes that the “ACP prices were in many instances less expensive than REC prices, and as a result suppliers chose to pay the ACP.”[220] The total cost of compliance for 2024 was $616.9 million, a 9.3 percent increase over 2023.

The Public Utilities Commission of Ohio reported that 7,532,762 RECs were retired in the 2023 compliance year, which is 4.6 percent higher than the number of RECs retired in 2023.[221] Compliance costs for 2023 were $79.8 million, 17.9 percent higher than 2022.

Delmarva Power is the only retail electric supplier that must file a compliance report with the Delaware Public Service Commission. The Delmarva report provides limited public information on RPS compliance cost.[222] Delmarva reports $13.0 million in ACPs but no other compliance cost information is available.

The Illinois Power Agency (IPA) reported delivery of ComEd RECs totaling 5,386,612. The ComEd compliance cost for the 2024/2025 RPS compliance year was $132.1 million, a 40.1 percent increase over 2023/2024.[223]

217 "Alternative Energy Portfolio Standards Act of 2004 Compliance for Reporting Year 2024-25," (February 5, 2026), <https://www.puc.pa.gov/filing-resources/reports/alternative-energy-portfolio-standards-aeps-reports/>

218 "Renewable Energy Portfolio Standard, A Report for Compliance Year 2024," Public Service Commission of the District of Columbia (May 1, 2025), <https://dcpsc.org/Orders-and-Regulations/PSC-Reports-to-the-DC-Council/Renewable-Energy-Portfolio-Standard.aspx>.

219 "Renewable Energy Portfolio Standard Report with Data for Calendar Year 2024," Public Service Commission of Maryland (November 25, 2025) at 9, <https://www.psc.state.md.us/commission-reports/>.

220 Id. at 8.

221 "Renewable Portfolio Standard Report to the General Assembly for Compliance Year 2023," Public Utilities Commission of Ohio (January 22, 2025), <https://puco.ohio.gov/utilities/electricity/resources/ohio-renewable-energy-portfolio-standard/puco-annual-rps-reports>.

222 "Retail Electricity Supplier's RPS Compliance Report, Compliance Period: June 1, 2022–May 31, 2023," Delmarva Power, (Sept. 29, 2023), <https://depsc.delaware.gov/rps-and-green-power-product-compliance/>.

223 "Annual Report Fiscal Year 2025" at 131, Illinois Power Agency (Feb. 17, 2026), <https://ipa.illinois.gov/about-ipa/ipa-publications.html>.

The North Carolina Utilities Commission reported that Dominion North Carolina Power submitted its 2020 compliance report on August 10, 2021. The compliance report stated that Dominion met its general RPS requirement by purchasing 427,657 credits that consisted of wind and biomass RECs and energy efficiency credits (EECs).[224] Dominion met its solar requirement of 8,562 RECs, poultry waste requirement of 22,311 RECs, and swine waste requirement of 2,997 RECs through REC purchases. Dominion North Carolina's total REC requirements for 2020 increased 4.9 percent over 2019.

The Michigan Public Service Commission reported that Indiana Michigan Power Company met the 2020 standard by generating or acquiring 315,384 RECs.[225]

New Jersey's Office of Clean Energy posted a summary of RPS compliance through the energy year ending May 31, 2024.[226] Electric power suppliers retired 14,449,269 class I RECs and 1,781,131 class II RECs. Suppliers submitted 298 class I ACPs and 54 class II ACPs at a cost of $50 per MWh. Electric power suppliers retired 3,156,170 solar RECs and 334,948 SACPs were submitted at a cost of $218 per MWh. Additionally, 958,816 transition RECs were retired and 341,632 SREC II were retired.[227] [228]

Table 8-28 shows the RPS compliance cost incurred by PJM jurisdictions as reported by the jurisdictions.[229] The compliance costs are the cost of acquiring RECs plus the cost of any alternative compliance payments. The cost of complying with RPS, as reported by the states, was $14.6 billion over the ten year period from 2014 through 2023 for the ten jurisdictions that had RPS and reported compliance costs.[230] The average RPS compliance cost per year based on the reported compliance cost for the ten year period from 2014 through 2023 was $1.5 billion. The compliance cost for 2023, the most recent year with almost complete data, was $2.9 billion.

224 "Annual Report Regarding Renewable Energy and Energy Efficiency Portfolio Standard in North Carolina," North Carolina Utilities Commission (Oct. 1, 2021) at 41, <https://www.ncuc.gov/newsroom.html>.

225 "Report on the Implementation and Cost-Effectiveness of the P.A. 295 Renewable Energy Standard," Michigan Public Service Commission (Feb. 15, 2022), <https://www.michigan.gov/mpsc/regulatory/reports/prior-renewable-reports>.

226 See EY22 RPS Compliance Results (2004 to 2022), New Jersey's Clean Energy Program (2023), <http://www.njcleanenergy.com/renewable-energy/program-updates/rps-compliance-reports>.

227 "New Jersey Board of Public Utilities Approves Solar Transition Program, Initiates a Cost Cap Proceeding," New Jersey Board of Public Utilities Press Release (December 6, 2019) <https://www.bpu.state.nj.us/bpu/newsroom/2019/approved/20191206.html>.

228 "NJBPU Approves 3,750 MW Successor Solar Incentive Program", New Jersey Board of Public Utilities Press Release (July 28, 2021) <https://www.nj.gov/bpu/newsroom/2021/approved/20210728.html>.

229 RPS compliance cost totals for Illinois, Michigan, and North Carolina reflect the RPS compliance cost attributable to PJM load in each of the states.

230 The actual PJM RPS compliance cost exceeds the reported $14.6 billion due to incomplete data. The compliance cost data for Delaware, Michigan and North Carolina are not available for some years. Based on past data these states generally account for approximately 2 percent of the total RPS compliance cost of PJM states. The $14.6 billion cost also does not fully reflect the overhead and administrative costs associated with RPS programs.

Table 8-28 RPS Compliance Cost[231 232 233 234 235 236 237 238 239 240 241]

Jurisdiction with RPS		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Delaware	Total RPS		$16,013,421	$18,409,631	$18,772,855	$18,341,916	$19,401,476	$21,133,971	$25,550,239		
	Solar		$7,070,254	$7,748,073	$7,105,726	$6,565,240	$8,121,914	$9,096,298	$9,567,891		
	Non-Solar		$8,943,167	$10,661,557	$11,667,129	$11,776,676	$11,279,562	$12,037,673	$15,982,348		
Illinois	Total RPS	$19,900,679	$19,893,704	$23,538,303	$25,919,372	$25,775,523	$26,971,638	$34,726,109	$52,555,157	$73,185,068	$88,917,610
Maryland	Total RPS	$104,056,879	$126,752,147	$135,232,457	$72,064,102	$84,874,724	$142,275,744	$223,218,944	$409,846,140	$438,832,999	$564,208,521
	Solar	$29,388,337	$39,062,714	$45,556,987	$21,276,834	$27,352,183	$57,824,616	$122,973,787	$221,296,225	$187,244,056	$165,520,809
	Tier I	$70,677,220	$85,070,001	$88,234,024	$50,099,228	$56,473,113	$84,333,097	$99,836,397	$187,579,231	$247,158,373	$387,296,886
	Tier II	$3,991,322	$2,619,432	$1,441,446	$688,040	$1,049,428	$118,031	$408,760	$970,684	$4,430,570	$9,666,831
	Geothermal										$1,723,995
Michigan	Total RPS	$476,535		$3,264,504	$3,961,262	$3,264,504	$3,376,773	$5,379,970			
New Jersey	Total RPS	$395,782,297	$524,761,382	$593,441,037	$606,312,461	$653,810,457	$763,108,366	$970,177,803	$1,140,654,336	$1,236,035,486	$1,346,551,069
	Solar	$322,504,920	$417,359,783	$481,540,738	$503,797,182	$560,509,712	$667,975,153	$822,247,072	$946,434,884	$959,987,769	$911,001,605
	Class I	$66,071,749	$98,185,431	$100,910,465	$91,872,615	$83,474,335	$85,522,028	$130,272,633	$171,818,089	$241,810,299	$386,567,274
	Class II	$7,205,628	$9,216,167	$10,989,834	$10,642,664	$9,826,410	$9,611,185	$17,658,099	$22,401,364	$34,237,418	$48,982,190
North Carolina	Total RPS	$297,513	$358,436	$317,644	$234,264	$442,579					
Ohio	Total RPS	$42,581,477	$42,584,233	$37,631,481	$39,943,836	$50,214,523	$69,799,170	$81,752,397	$82,677,088	$67,708,887	$79,837,069
	Solar	$17,666,730	$14,843,052	$11,564,584	$9,435,730	$9,419,092	$9,578,048	$0	$0	$0	$0
	Non-Solar	$24,914,747	$27,741,181	$26,066,897	$30,508,106	$40,795,431	$60,221,121	$81,752,397	$82,677,088	$67,708,887	$79,837,069
Pennsylvania	Total RPS	$86,184,477	$114,586,932	$125,041,911	$115,585,212	$99,681,713	$112,691,066	$182,995,718	$307,751,404	$461,430,587	$630,531,984
	Solar	$14,163,543	$19,227,690	$21,876,876	$17,987,722	$16,565,924	$20,608,103	$24,764,538	$27,673,083	$28,464,498	$26,306,505
	Tier I	$70,922,431	$94,339,032	$101,700,328	$95,370,456	$77,899,586	$74,780,310	$100,528,434	$159,457,100	$224,782,412	$292,270,379
	Tier II	$1,098,503	$1,020,210	$1,464,707	$2,227,034	$5,216,203	$17,302,653	$57,702,746	$120,621,222	$208,183,678	$311,955,100
Washington D.C.	Total RPS	$27,373,000	$38,541,000	$47,163,000	$42,700,000	$50,600,000	$57,300,000	$65,000,000	$99,100,000	$129,200,000	$168,600,000
	Solar	$25,145,000	$36,523,000	$44,898,000	$31,800,000	$42,800,000	$50,560,000	$59,200,000	$84,000,000	$106,600,000	$116,800,000
	Tier I	$2,141,000	$1,901,000	$2,131,500	$10,500,000	$7,600,000	$6,670,000	$5,800,000	$15,100,000	$22,600,000	$51,800,000
	Tier II	$87,000	$117,000	$133,500	$400,000	$200,000	$70,000	$0	$0	$0	$0
PJM	Total RPS	$676,652,857	$883,491,256	$984,039,969	$925,493,363	$987,005,938	$1,194,924,232	$1,584,384,913	$2,118,134,365	$2,406,393,026	$2,878,646,253

231 Several states have not released compliance reports for 2023.

232 "Retail Electricity Supplier's RPS Compliance Report," Delmarva Power (Sept. 28, 2022), <https://depsc.delaware.gov/rps-and-green-power-product-compliance/>

233 "Fiscal Year 2024 Annual Report," February 18, 2024, Illinois Power Agency (IPA), <https://ipa.illinois.gov/about-ipa/ipa-publications.html>.

234 "Renewable Energy Portfolio Standard Report," Public Service Commission of Maryland (December 2, 2024) at 9, <https://www.psc.state.md.us/commission-reports/>.

235 Appendix C in "Report on the Implementation and Cost-Effectiveness of the P.A. 295 Renewable Energy Standard," Michigan Public Service Commission, February 15, 2022, <https://www.michigan.gov/mpsc/regulatory/reports/prior-renewable-reports> The compliance cost entry reflects the compliance cost of the Indiana Michigan Power Company, which is the only investor owned utilities whose service area is in the PJM footprint.

236 "RPS Report Summary 2005-2024," New Jersey's Clean Energy Program, May 2025, <http://njcleanenergy.com/renewable-energy/program-updates/rps-compliance-reports>.

237 "Renewable Portfolio Standard Report to the General Assembly for Compliance Year 2023," Public Utilities Commission of Ohio, January 22, 2025, <https://puco.ohio.gov/wps/portal/gov/puco/utilities/electricity/resources/ohio-renewable-energy-portfolio-standard/puco-annual-rps-reports>.

238 "Alternative Energy Portfolio Standards Act of 2004 Compliance for Reporting Year 2023-24," Pennsylvania Public Utility Commission, June 2025 <https://www.puc.pa.gov/filing-resources/reports/alternative-energy-portfolio-standards-aeps-reports/>

239 "Report on the Renewable Energy Portfolio Standard for Compliance Year 2023," Public Service Commission of the District of Columbia, Executive Summary, May 1, 2024, <https://dcpsc.org/Orders-and-Regulations/PSC-Reports-to-the-DC-Council/Renewable-Energy-Portfolio-Standard.aspx>.

240 "Application of Dominion Energy North Carolina for Approval of Cost Recovery for Renewable Energy and Energy Efficiency Portfolio Standard Compliance and Related Costs," Docket No. E-22, Sub 557, Sub 558, August 30, 2018 <https://www.ncuc.net/>. The North Carolina compliance cost entries reflects the compliance cost of Dominion Energy North Carolina.

241 The reporting period for RPS compliance in Delaware, Illinois, New Jersey, and Pennsylvania corresponds to PJM capacity market delivery years, June 1 through May 31. The compliance cost amounts reported by these states were converted to calendar year by assuming the compliance cost was evenly spread across the months in the compliance year.

Offshore Wind Development

New Jersey, Maryland and Virginia have taken significant steps to promote offshore wind. New Jersey and Maryland enacted legislation for offshore wind renewable energy credits (ORECs) in 2010.[242] On November 1, 2013, the Bureau of Ocean Energy Management (BOEM), part of the U.S. Department of the Interior, awarded Dominion Energy a lease for development of the Coastal Virginia Offshore Wind (CVOW) project. CVOW is a wind farm project consisting of 176 turbines in federal waters 23 to 27 miles off Virginia Beach.[243] Dominion expects to complete the project in 2026.

On May 24, 2018, New Jersey enacted a statute directing the Board of Public Utilities (NJPBU) to create an OREC program targeting installation of at least 3,500 MW of offshore wind capacity by 2030 (plus 2,000 MW of energy storage capacity).[244] The New Jersey statute also reinstates certain tax incentives for offshore wind manufacturing activities. Governor Murphy has issued Executive Order No. 8, which calls for full implementation of the statute. The offshore wind target 3,500 MW by 2030 has since been replaced by a target of 7,500 MW by 2035.[245] The BPU opened a 100 day application window for qualified offshore wind projects on September 20, 2018, and on June, 21, 2019, the first award for a 1,100 MW offshore wind project was granted to Danish wind power developer Ørsted.[246] [247] Two more projects were approved on June 30, 2021. Ørsted was awarded a second project for offshore wind capacity of 1,148 MW and Atlantic Shores Offshore Wind was awarded a project for 1,510 MW.[248] On October 31, 2023, Ørsted announced that it was canceling two major offshore wind projects, Ocean Wind 1 (1,100 MW) and Ocean Wind 2 (1,148 MW), that were planned off the coast of New Jersey.[249]

The Associated Press reported in May 2024 that the New Jersey and Ørsted reached a settlement that required Ørsted to pay New Jersey $125 million.[250]

On January 24, 2024, the NJBPU awarded 2,400 MW of offshore wind capacity to the Leading Light Wind project and 1,342 to Attentive Energy LLC.[251] The Leading Light Wind project is a partnership between Invenergy and energyRE.

On December 17, 2021, the Maryland Public Service Commission awarded ORECs in its Round 2 solicitation to the 846 MW Skipjack Wind 2 offshore project, owned by Skipjack Offshore Energy LLC, an Ørsted subsidiary, and to the 808.5 MW Momentum Wind offshore project, owned by US Wind Inc.[252] ORECs for Skipjack Wind 2 have a levelized price of $71.61; ORECs for Momentum Wind have a levelized price of $54.17.[253] Both projects are expected to become operational before the end of 2026.[254] In 2017, Round 1 ORECs were awarded to Deepwater Wind's 120-MW Skipjack Wind Farm, later acquired by Ørsted, and U.S. Wind's 248 MW project.[255] On January 25, 2024, Ørsted announced it "has withdrawn from the Maryland Public Service Commission Orders approving the Skipjack 1 and 2 projects," noting that the OREC prices in the orders "are no longer commercially viable."[256]

On July 1, 2019, Dominion Energy announced the beginning of construction on an offshore wind demonstration project. The project consists of two 6 MW offshore wind turbines.[257] In September 2019, Dominion filed an interconnection agreement with PJM associated with its proposal to develop a 2,600 MW offshore wind farm.[258]

On January 20, 2025, the Trump Administration issued a Presidential Memorandum withdrawing "from disposition for wind energy leasing all areas

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

243 See Dominion Energy, Coastal Virginia Offshore Wind <*https://www.dominionenergy.com/about/delivering-energy/wind-power-projects/coastal-virginia-offshore-wind*> .

244 N.J. S. 2314/A. 3723.

245 Executive Order 92, Philip D. Murphy, Governor of New Jersey (November 19, 2019) <https://nj.gov/infobank/eo/056murphy/approved/eo_archive.html>.

246 BPU Docket No. QO18080851.

247 "New Jersey Board of Public Utilities Awards Historic 1,100 MW Offshore Wind Solicitation to Orsted's Ocean Wind Project," New Jersey BPU Press Release (June 21, 2019) <https://nj.gov/bpu/newsroom/2019/approved/20190621.html>.

248 "NJPBU Approves Nation's Largest Combined Offshore Wind Award to Atlantic Shores and Ocean Wind II", New Jersey BPU Press Release (June 30, 2021) <https://www.nj.gov/bpu/newsroom/2021/approved/20210630.html>.

249 "Ørsted ceases development of its US offshore wind projects Ocean Wind 1 and 2, takes final investment decision on Revolution Wind, and recognises DKK 28.4 billion impairments" (October 31, 2023) <https://orsted.com/en/company-announcement-list/2023/10/oersted-ceases-development-of-its-us-offshore-wind-73751> .

250 "New Jersey and wind farm developer Ørsted settle claims for $125M over scrapped offshore projects", Associated Press (May 28, 2024).

251 "NJBPU Approves Over 3,700 MW of Offshore Wind Capacity in Combined Award", New Jersey BPU Press Release (January 24, 2024) <https://www.nj.gov/bpu/newsroom/2024/approved/20240124.html>.

252 "Ørsted, US Wind Triumph with 1.6 GW in Maryland Offshore Tender," Renewables Now (December 20, 2021) <https://renewablesnow.com/news/rsted-us-wind-triumph-with-1-6-gw-in-maryland-offshore-tender-766237/>.

253 *Id.*

254 *Id.*

255 "Orsted Acquires Deepwater Wind and creates leading US Offshore Wind Platform," ORSTED Press Release (August 10, 2018).

256 Skipjack Wind to be Repositioned for Future Offtake Opportunities, Ørsted (January 25, 2024) <https://orsted.com/en/media/news/2024/01/skipjack-wind-to-be-repositioned-for-future-offtak-815811>.

257 "Construction Begins on Dominion Energy Offshore Wind Project," Dominion Energy News Release (July 1, 2019) <https://news.dominionenergy.com/2019-07-01-Construction-Begins-on-Dominion-Energy-Offshore-Wind-Project>.

258 "Dominion Energy Announces Largest Offshore Wind Project in US," Dominion Energy News Release (September 19, 2019) <https://news.dominionenergy.com/2019-09-19-Dominion-Energy-Announces-Largest-Offshore-Wind-Project-in-US>.

within the Offshore Continental Shelf."[259] The withdrawal effectively puts on hold indefinitely the offshore wind projects in New Jersey and Maryland. On May 5, 2025, the Attorneys General of New Jersey and Maryland, along with the 16 other states, filed suit against the Trump Administration over the withdrawal of offshore leasing.[260] [261]

On December 22, 2025, citing national security concerns, the Department of the Interior announced it was pausing, effective immediately, the federal leases for all large scale offshore wind projects currently under construction, including Dominion Energy's CVOW.[262]

Natural Gas Pipeline Infrastructure

FERC Rules

By order issued October 7, 2025, the Commission repealed Section 157.23 of its rules stating that it sought to "advance the Commission's principal statutory mission under the Natural Gas Act 'to encourage the orderly development of plentiful supplies of . . . natural gas at reasonable prices.'"[263] Section 157.23 prevented the start of construction of projects approved under NGA section 3 or section 7 for a period of time during the pendency of a rehearing request. Removal of section 157.23 allows the construction of projects to proceed upon approval.[264]

Transco Regional Energy Access Expansion Project

By order issued January 11, 2023, FERC authorized a request filed by Transco to modify its gas pipeline system to increase its capacity by 829,400 Dth/d (.8 BCF/d) from the north east on its Leidy line to points in Pennsylvania, New Jersey and Maryland. Transco planned to have service available at the end of the fourth quarter of 2023.[265] In order to increase the capacity on the pipeline for this project Transco installed about 36 miles of new pipe, a new electric compressor station and modified five existing compressor stations. By letter dated July 26, 2024, FERC authorized Transco to commence service with facilities associated with the Regional Energy Expansion Project.[266] The 829,400 Dth/d would be enough to supply about three combined cycle power plants.[267] On March 13, 2023, the New Jersey Division of Rate Counsel and New Jersey Conservation Foundation, et al., sought review in the United States Court of Appeals for the District of Columbia Circuit.[268] The appeal primarily argues that FERC ignored evidence that "clearly demonstrated that the state of New Jersey does not need and will not benefit from the Project's capacity."[269] On July 30, 2024, the United States Court of Appeals for the District of Columbia Circuit vacated and remanded the Certificate Orders.[270] On September 6, 2024, Transco filed an Application for Temporary Emergency Certificate so they could continue to provide service while this matter is resolved on remand.[271] Both PJM and the MMU submitted comments supporting the application.[272] On January 24, 2025, FERC issued an order reinstating authorization for Transco's Regional Energy Access Expansion Project.[273]

Mountain Valley Pipeline

"On October 23, 2015, Mountain Valley Pipeline (MVP) filed an application with FERC for approval to construct own and operate MVP."[274] On October 13, 2017, MVP received a certificate of convenience and necessity from FERC. The pipeline is approximately 303 miles long stretching from the Equitrans Transmission system in Wentzel County West Virginia to Transco Zone 5 station 165 in Pittsylvania County Virginia. The capacity of the pipeline is approximately 2 BCF per day. On June 14, 2024, MVP entered service.[275] The

259 *Temporary Withdrawal of all Areas on the Outer Continental Shelf from Offshore Wind Leasing and Review of the Federal Government's Leasing and Permitting Practices for Wind Projects*, Presidential Memorandum (January 20, 2025) <https://www.whitehouse.gov/presidential-actions/2025/01/temporary-withdrawal-of-all-areas-on-the-outer-continental-shelf-from-offshore-wind-leasing-and-review-of-the-federal-governments-leasing-and-permitting-practices-for-wind-projects/>.
260 State of New York v. Trump, Case NO. 1:25-cv-11221 (Dist. of Mass. May 5, 2025).
261 *Attorney General Platkin Sues Trump Administration for Halting Development of Wind Energy*, New Release of the Attorney General for the State of New Jersey (May 5, 2025) <https://www.njoag.gov/news/>.
262 See Department of the Interior, *<https://www.doi.gov/pressreleases/trump-administration-protects-us-national-security-pausing-offshore-wind-leases>*.
263 *See Removal of Regulations Limiting Authorizations*, 193 FERC ¶ 61,014 (October 7, 2025).
264 *Id.* at P 31.
265 See 182 FERC ¶ 61,006 (2023), *order on reh'g*, 182 FERC ¶ 61,148 (2023), *order on reh'g*, 183 FERC ¶ 61,071 (2023).
266 See Letter: Authorization to Commence Service, FERC Docket No. CP21-94-000.
267 See *2025 Annual State of the Market Report for PJM*, Volume 2: Section 7, Net Revenue, "Table 7-59 Gas pipeline capacity need to replace units at risk of retirement." New combined cycle unit ICAP 1,362 MW and fuel rate of 6.543 MMBtu/MWh.
268 Case No. 23-1064, et al.
269 New Jersey Conservation Foundation, et al. v. FERC, Proof Opening Brief of Petitioners, Case No. 23-1064 (D.C. Cir July 26, 2023).
270 N.J. Conservation Foundation, et. al v. FERC, No. 23-1064 (July 30, 2024).
271 See FERC Docket No. CP21-94-004.
272 See PJM Interconnection, L.L.C.'s Comments in Support of the Application of Transcontinental Gas Pipe Line Company, LLC for a Temporary Emergency Certificate, FERC Docket No. CP21-94-004 (October 7, 2024); Comments of the Independent Market Monitor for PJM, FERC Docket No. CP21-94-004 (October 8, 2024).
273 See FERC Docket No. CP21-94-004.
274 Mountain Valley Pipeline <https://www.mountainvalleypipeline.info/> (Accessed July 26, 2024).
275 Mountain Valley Pipeline <https://www.mountainvalleypipeline.info/> (Accessed July 26, 2024).

2,000,000 Dth/d would be enough to supply about nine combined cycle power plants.[276]

Mountain Valley Pipeline MVP Boost Expansion Project

On October 23, 2025, Mountain Valley Pipeline (MVP) filed an abbreviated application for a certificate of convenience and necessity with FERC for the MVP Boost Expansion Project. This project will increase the capacity of the MVP pipeline by 600,000 Dth/day. The increased capacity will be achieved by increasing compression at three existing compressor stations in West Virginia and construction of a new compressor station in Virginia. The expected completion of the project is mid-2028.[277] The increase in the MVP pipelines capacity by 600,000 Dth/d would be enough to supply three combined cycle power plants.[278]

Transco Southeast Supply Enhancement

On May 24, 2024, Transcontinental Gas Pipe Line Company, LLC (Transco) filed a general project description draft of the proposed Southeast Supply Enhancement Project. This project is an expansion of the Transco system in southern Virginia, North Carolina, South Carolina, Georgia and Alabama. The total capacity will be 1,591,900 Dth/d from Transco Station 165 Zone 5 and the interconnection with Mountain Valley and points south to North Carolina, South Carolina, Georgia and Alabama. The proposal includes about 55 miles of new pipe and the addition of seven new compressors at existing compressor stations. The expected completion of the project is June 2028.[279] The 1,591,900 Dth/d would be enough to supply about seven combined cycle power plants.[280]

276 See *2025 Annual State of the Market Report for PJM*, Volume 2: Section 7, Net Revenue, "Table 7-59 Gas pipeline capacity need to replace units at risk of retirement." New combined cycle unit ICAP 1,362 MW and fuel rate of 6.543 MMBtu/MWh.
277 See FERC Docket No. CP26-14.
278 See *2025 Annual State of the Market Report for PJM*, Volume 2: Section 7, Net Revenue: Table 7-59" New combined cycle unit ICAP 1,362 MW and fuel rate of 6.543 MMBtu/MWh.
279 See Transcontinental Gas Pipe Line Company, LLC Southeast Supply Enhancement Project, Docket No. PF24-2-000, Draft Resource Reports 1-12 (May 24, 2024).
280 See *2025 Annual State of the Market Report for PJM*, Volume 2: Section 7, Net Revenue: Table 7-59" New combined cycle unit ICAP 1,362 MW and fuel rate of 6.543 MMBtu/MWh.

Transco Commonwealth Energy Connector Project

On August 24, 2022, Transcontinental Gas Pipe Line Company, LLC (Transco) filed a certificate of public convenience and necessity to construct the Commonwealth Energy Connector Project.[281] The new capacity will be 105,000 Dth/d which Virginia Natural Gas, Inc. (VNG) has contracted for. This project is an expansion of the Transco system from Zone 5 Pooling point through Transco's South Virginia Lateral which interconnects between Transco and Columbia Gas Transmission, LLC. Additional compression, about 3.6 miles of additional pipe and modifications and installation of new facilities at the Emporia M&R station will be completed to increase the capacity. The project was approved by FERC on October 23, 2025, to go into service.[282] The 105,000 Dth/d would not be enough supply to run one combined cycle power plant [283]

Columbia Gas Transmission Virginia Reliability Project

On August 24, 2022, Columbia Gas Transmission LLC (Columbia) filed an abbreviated application for the authority necessary to construct and operate its Virginia Reliability project. The new capacity will be 100,000 Dth/d which Virginia Natural Gas, Inc. (VNG) has contracted for. This project will replace 49 miles of existing pipe, modifications at two compressor stations, modifications to one receipt point and delivery point increasing service to Market Area 34. This will allow VNG to receive gas at the Transco Columbia interconnection and deliver to VNG. This capacity was approved by FERC October 28, 2025 to go into service.[284] The 100,000 Dth/d would not be enough supply to run one combined cycle power plant.[285]

Columbia Gulf Transmission Pulaski Expansion Project

On October 15, 2025, Columbia Gulf Transmission, LLC (Columbia Gulf) filed an abbreviated application for certificate of convenience and necessity with FERC for the Pulaski Expansion Project. The new capacity will be 260,000 Dth/d which EKPC entered into a 20 year precedent agreement. This project

281 See FERC Docket No. CP22-502.
282 See FERC Docket No. CP22-502 Filed October 23, 2025.
283 See *2025 Annual State of the Market Report for PJM*, Volume 2: Section 7, Net Revenue, Table 7-59. New combined cycle unit ICAP 1,362 MW and fuel rate of 6.543 MMBtu/MWh.
284 See FERC Docket No. CP22-503.
285 See *2025 Annual State of the Market Report for PJM*, Volume 2: Section 7, Net Revenue, Table 7-59. New combined cycle unit ICAP 1,362 MW and fuel rate of 6.543 MMBtu/MWh.

will constructed with approximately 41 miles of 30 inch pipeline to one new delivery point EKPC's Cooper Station. The projected in service date is February 1, 2029.[286] The 260,000 Dth/d would be enough to supply about one combined cycle power plant.[287]

Columbia Gulf Transmission Maysville Expansion Project

On November 17, 2025, Columbia Gulf Transmission, LLC (Columbia Gulf) filed an abbreviated application for certificate of convenience and necessity with FERC for the Maysville Project. The new capacity will be 340,000 Dth/d which EKPC entered into a 20 year precedent agreement. This project will constructed with approximately 42 miles of 30 inch pipeline to one new delivery point EKPC's Spurlock Station. The projected in service date is February 1, 2029.[288] The 340,000 Dth/d would be enough to supply about one combined cycle power plant.[289]

Texas Eastern Transmission Appalachia to Market II Project

On July 7, 2022, Texas Eastern Transmission, LP (Texas Eastern) filed an abbreviated application for a certificate of public convenience and necessity to develop the Appalachia to Market II Project. Prior to the filing, Texas Eastern conducted a binding open season for 55,000 Dth/d that will be made available based on improvements to the Texas Eastern system. The additional capacity will run from Appalachia supply basin in southwest Pennsylvania to New Jersey. Two compressor stations (reducing air emissions with upgraded compression equipment) will be replaced and two miles of looping of pipe will be added. PSEG Power LLC and Elizabethtown Gas signed up for the 55,000 Dth/d. The project is expected to be completed by Jun 30, 2027.[290] The 55,000 Dth/d would not be enough supply to run one combined cycle power plant.[291]

286 See FERC Docket No. CP26-11.
287 See *2025 Annual State of the Market Report for PJM*, Volume 2: Section 7, Net Revenue, Table 7-59. New combined cycle unit ICAP 1,362 MW and fuel rate of 6.543 MMBtu/MWh.
288 See FERC Docket No. CP26-25.
289 See *2025 Annual State of the Market Report for PJM*, Volume 2: Section 7, Net Revenue, Table 7-59. New combined cycle unit ICAP 1,362 MW and fuel rate of 6.543 MMBtu/MWh.
290 See FERC Docket No. CP22-486-000.
291 See *2025 Annual State of the Market Report for PJM*, Volume 2: Section 7, Net Revenue, Table 7-59. New combined cycle unit ICAP 1,362 MW and fuel rate of 6.543 MMBtu/MWh.

Eastern Gas Transmission and Storage Inc. Capital Area Project

On December 11, 2024 Eastern Gas Transmission and Storage (EGTS) filed an abbreviated application for a certificate of public convenience and necessity to develop the Capital Area Project. The new capacity will be 67,500 Dth/d which Washington Gas Light Company (WGL) has contracted for. This project will increase EGTS capacity from the Leidy Area in Pennsylvania to points in Maryland and Virginia. Additional compression will be added at four compressor stations: Centre Compression Station, Chambersburg Compression Station, Leesburg Compression Station and Finnerfrock Compression Station. The expected completion date is November 1, 2027.[292] The 67,500 Dth/d would not be enough supply to run one combined cycle power plant.[293]

Eastern Gas Transmission and Storage Appalachian Reliability Project

On July 24, 2025, Eastern Gas Transmission and Storage, Inc. filed an abbreviated application for a certificate of public convenience and necessity to construct the Appalachian Reliability Project. The new capacity will be approximately 550,000 Dth/d of capacity. The capacity will be from western Pennsylvania for delivery to Texas Eastern Transmission LP in Westmoreland County Pennsylvania and Rockies Express Pipeline LLC in Monroe County Ohio. This project will install approximately 3.9 miles of pipeline, install one new compressor station and modify two other compressor stations. The project in service date is projected to be in June of 2028.[294] The 550,000 Dth/d would be enough supply to run two combined cycle power plant.[295]

Emission Controlled Capacity and Emissions

Emission Controlled Capacity

Environmental regulations affect decisions about emission control investments in existing units, investment in new units and decisions to retire units lacking

292 See FERC Docket No. CP25-29-000.
293 See *2025 Annual State of the Market Report for PJM*, Volume 2: Section 7, Net Revenue, Table 7-59. New combined cycle unit ICAP 1,362 MW and fuel rate of 6.543 MMBtu/MWh.
294 See FERC Docket No. CP25-528.
295 See *2025 Annual State of the Market Report for PJM*, Volume 2: Section 7, Net Revenue, Table 7-59. New combined cycle unit ICAP 1,362 MW and fuel rate of 6.543 MMBtu/MWh.

emission controls.[296] Most PJM units burning fossil fuels have installed emission control technology. All coal steam units in PJM are compliant with the state and federal emissions limits established by MATS.[297] [298]

Table 8-29 shows SO_2 emission controls by fossil fuel fired units in PJM.[299] [300] [301] Coal has the highest SO_2 emission rate, while natural gas and diesel oil have lower SO_2 emission rates.[302] Of the current 34,835.5 MW of coal capacity in PJM, 34,066.5 MW of capacity, 97.8 percent, has some form of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions.

Table 8-29 SO_2 emission controls by fuel type (MW): March 31, 2026[303]

	SO2 Controlled	No SO2 Controls	Total	Percent Controlled
Coal	34,066.5	769.0	34,835.5	97.8%
Diesel Oil	0.0	1,698.8	1,698.8	0.0%
Natural Gas	0.0	77,381.7	77,381.7	0.0%
Other	325.0	603.0	928.0	35.0%
Total	34,391.5	80,452.5	114,844.0	29.9%

Table 8-30 shows NO_X emission controls by fossil fuel fired units in PJM. Coal has the highest NO_X emission rate, while natural gas and diesel oil have lower NO_X emission rates. Of the current 34,835.5 MW of coal capacity in PJM, 34,749.5 MW of capacity, 99.8 percent, has some form of emissions controls to reduce NO_X emissions. Most units in PJM have NO_X emission controls in order to meet each state's emission compliance standards, based on whether a state is part of CSAPR, Acid Rain Program (ARP) or a combination of the three. The NO_X compliance standards of MATS require the use of selective catalytic reduction (SCRs) or selective non-catalytic reduction (SCNRs) for coal steam units, as well as SCRs or water injection technology for peaking combustion turbine units.[304]

Table 8-30 NO_X emission controls by fuel type (MW): As of March 31, 2026

	NOx Controlled	No NOx Controls	Total	Percent Controlled
Coal	34,749.5	86.0	34,835.5	99.8%
Diesel Oil	952.7	746.1	1,698.8	56.1%
Natural Gas	75,564.7	1,817.0	77,381.7	97.7%
Other	775.0	153.0	928.0	83.5%
Total	112,041.9	2,802.1	114,844.0	97.6%

Table 8-31 shows particulate emission controls by fossil fuel units in PJM. Almost all coal units (99.8 percent) in PJM have particulate controls, as well as a few natural gas units (1.1 percent) and units with other fuel sources (83.5 percent). Typically, technologies such as electrostatic precipitators (ESP) or fabric filters (baghouses) are used to reduce particulate matter from coal steam units.[305] Fabric filters work by allowing the flue gas to pass through a tightly woven fabric which filters out the particulates. Of the current 34,835.5 MW of coal capacity in PJM, 34,750.5 MW of capacity, 99.8 percent, have some type of particulate emissions control technology.

Table 8-31 Particulate emission controls by fuel type (MW): As of March 31, 2026

	Particulate Controlled	No Particulate Controls	Total	Percent Controlled
Coal	34,750.5	85.0	34,835.5	99.8%
Diesel Oil	0.0	1,698.8	1,698.8	0.0%
Natural Gas	863.0	76,518.7	77,381.7	1.1%
Other	775.0	153.0	928.0	83.5%
Total	36,388.5	78,455.5	114,844.0	31.7%

In order to achieve compliance with MATS, most coal steam units in PJM have particulate emission controls in the form of ESPs, but many units have also installed baghouse technology, or a combination of an FGD and SCR.

296 See EPA, "National Ambient Air Quality Standards (NAAQS)," <https://www.epa.gov/criteria-air-pollutants/naaqs-table> (Accessed March 4, 2022).
297 On April 16, 2020, the EPA issued a revised final finding regarding the Mercury and Air Toxics Standards. See EPA. "Regulatory Actions," <https://www.epa.gov/mats/regulatory-actions-final-mercury-and-air-toxics-standards-mats-power-plants> (Accessed May 7, 2020).
298 On April 9, 2020, the EPA created a new subcategory of six coal refuse power plants in Pennsylvania and West Virginia with reduced limits of HCl and SO_2 emissions under MATS. These units were all compliant with the previous MATS rules. "Mercury and Air Toxics Standards,"<https://www.epa.gov/sites/production/files/2020-04/documents/frn_mats_coal_refuse_2060-au48_final_rule.pdf> (Accessed May 7, 2020)
299 See EPA, "Air Market Programs Data," <http://ampd.epa.gov/ampd/> (Accessed March 4, 2022).
300 Air Markets Programs Data is submitted quarterly. Generators have 30 days after the end of the quarter to submit data, and all data is considered preliminary and subject to change until it is finalized in June of the following year. The most recent complete set of emissions data is from 2024.
301 The total MW are less than the 184,201.9 reported in Section 5: Capacity Market of this report, because EPA data on controls could not be matched to some PJM units. "Air Markets Program Data," <http://ampd.epa.gov/ampd/QueryToolie.html> (Accessed January 1, 2025).
302 Diesel oil includes number 1, number 2, and ultra-low sulfur diesel. See EPA, "Electronic Code of Federal Regulations, Title 40, Chapter 1, Subchapter C, Part 72, Subpart A, Section 72.2," <http://www.ecfr.gov/cgi-bin/text-idx?SID=4f18612541a393473efb13acb879d470&mc=true&node=se40.18.72_12&rgn=div8> (Accessed May 7, 2020).
303 The "other" category includes petroleum coke, wood, process gas, residual oil, other gas, and other oil. The EPA's "other" category does not have strict definitions for inclusion.
304 See EPA. "Mercury and Air Toxics Standards, Cleaner Power Plants," <https://www.epa.gov/mats/cleaner-power-plants#controls> (Accessed May 7, 2020).
305 See EPA, "Air Pollution Control Technology Fact Sheet," <https://www3.epa.gov/ttn/catc/dir1/ff-pulse.pdf> (Accessed May 4, 2022).

Currently, all of the 86 coal steam units have some combination of ESP, baghouse, or FGD and SCR technology installed to achieve MATS compliance for either SO_2 or particulate emissions control, representing all of the 34,835.5 MW total coal capacity.

Emissions

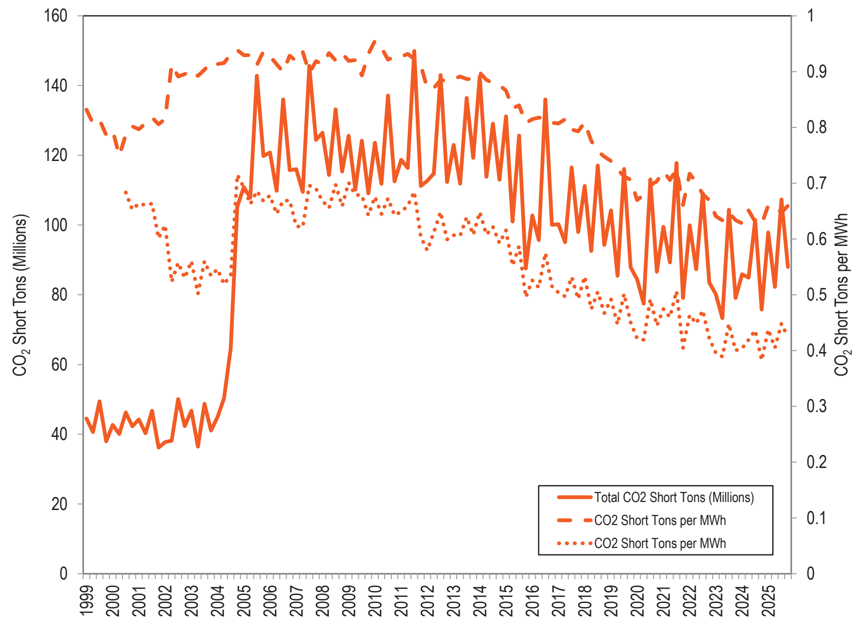
Figure 8-10 shows the total CO_2 emissions in short tons, the CO_2 emission rate in short tons per MWh within PJM for all CO_2 emitting units, for each quarter from 1999 to the fourth quarter of 2025, and the CO_2 emission rate in short tons per MWh of total generation within PJM for each quarter from the third quarter of 2000 to the fourth quarter of 2025.[306 307]

Figure 8-11 shows the total CO_2 emission in short tons on peak and off peak and the CO_2 emission rate in short tons per MWh for all CO_2 emitting units.

Table 8-32 shows the minimum and maximum CO_2 emission rates in short tons per MWh for all CO_2 emitting units, for all hours, as well as on and off peak hours, from the first quarter of 1999 through the fourth quarter of 2025.

Total PJM generation increased from 198,022.9 GWh in the fourth quarter of 2024 to 207,351.9 GWh in the fourth quarter of 2025, while CO_2 produced increased from 75.8 million short tons in the fourth quarter of 2024 to 88.0 million short tons in the fourth quarter of 2025.[308] The CO_2 emission rate averaged 0.63 short tons per MWh for all CO_2 emitting units in 2024, and 0.66 short tons per MWh for all CO_2 emitting units in 2025.

Figure 8-10 CO_2 emissions by quarter (millions of short tons), by PJM units: January 1999 through December 2025[309 310]

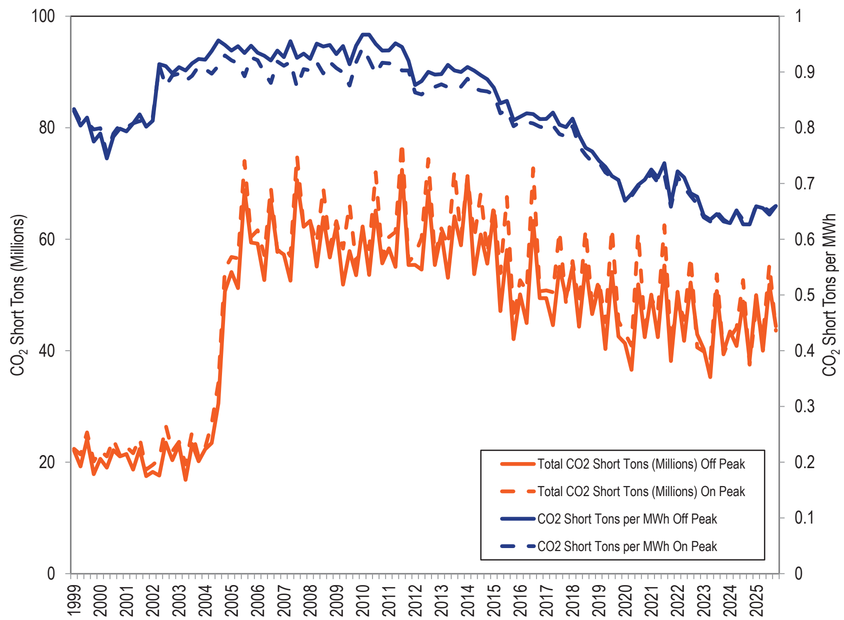


In the fourth quarter of 2025, CO_2 emission rates were 0.66 short tons per MWh for all CO_2 emitting units for off peak hours, and 0.66 short tons per MWh for on peak hours. Of the top 10 largest CO_2 emitting units in the United States, three (Gavin, Prairie State, and Amos) are located in the PJM footprint.[311]

306 Unless otherwise noted, emissions are measured in short tons. A short ton is 2,000 pounds.
307 At the time of this report, EPA emissions data for the first three months of 2026 was not yet available.
308 See the *2024 Annual State of the Market Report for PJM: Volume 2,* Section 3: Energy Market, Table 3-51.

309 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.
310 In 2004 and 2005, PJM integrated the American Electric Power (AEP), ComEd, Dayton Power & Light Company (DAY), Dominion, and Duquesne Light Company (DLCO) Control Zones. The large increase in total emissions from 2004 to 2005 was a result of these integrations. In June 2011, PJM integrated the American Transmission Systems, Inc. (ATSI) Control Zone. In January 2012, PJM integrated the Duke Energy Ohio/Kentucky (DEOK) Control Zone. In June 2013, PJM integrated the Eastern Kentucky Power Cooperative (EKPC). In December 2018, PJM integrated the Ohio Valley Electric Corporation (OVEC).
311 "The top 10 emitting power plants in America," <https://www.eenews.net/articles/the-top-10-emitting-power-plants-in-america/> (Accessed November 4, 2022).

Figure 8-11 Total CO_2 emissions during on and off peak hours by quarter (millions of short tons), by PJM units: 1999 through 2025[312]



312 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

Table 8-32 Minimum and maximum CO_2 emissions per MWh: 1999 through 2025

		Short Tons per MWh	Year	Quarter
Minimum	All hours	0.63	2024	4
	On Peak	0.63	2024	4
	Off Peak	0.63	2024	4
Maximum	All hours	0.96	2010	1
	On Peak	0.94	2010	1
	Off Peak	0.97	2010	2

Figure 8-12 shows the total SO_2 and NO_X emissions and the emission rate in short tons per MWh for all SO_2 and NO_X emitting units, and the SO_2 and NO_X emission rate in short tons per MWh of total PJM generation. In the fourth quarter of 2025, the SO_2 emission rate was 0.000316 short tons per MWh for all SO_2 emitting units, and the NOx emission rate was 0.000277 short tons per MWh for all NO_X emitting units.

Figure 8-13 shows the total on peak hour and off peak hour SO_2 and NO_X emissions and the emission rate in short tons per MWh for all SO_2 and NO_X emitting units. In the fourth quarter of 2025, SO_2 emission rates were 0.000317 short tons per MWh and 0.000316 short tons per MWh for all SO_2 units, for off and on peak hours. In the fourth quarter of 2025, NO_X emission rates were 0.000271 short tons per MWh and 0.000282 short tons per MWh for all NO_X emitting units, for off and on peak hours.

Table 8-33 shows the minimum and maximum SO2 and NOx emission rate in short tons per MWh for all SO_2 and NO_X emitting units, for all hours, as well as on and off peak hours, from the first quarter of 1999 through the fourth quarter of 2025.

The consistent decline in SO_2 and NO_X emissions starting in 2006 is the result of a decline in the use of coal, an increase in the use of natural gas, and the installation of environmental controls from 2006 to 2025.[313] [314]

313 See EIA, "Changes in coal sector led to less SO_2 and NO_x emissions from electric power industry,"<https://www.eia.gov/todayinenergy/detail.php?id=37752> (Accessed October 25, 2019).

314 See EIA, "Sulfur dioxide emissions from U.S. power plants have fallen faster than coal generation," <https://www.eia.gov/todayinenergy/detail.php?id=29812> (Accessed October 25, 2019).

Figure 8-12 SO_2 and NO_x emissions by quarter (thousands of short tons), by PJM units: 1999 through 2025[315]

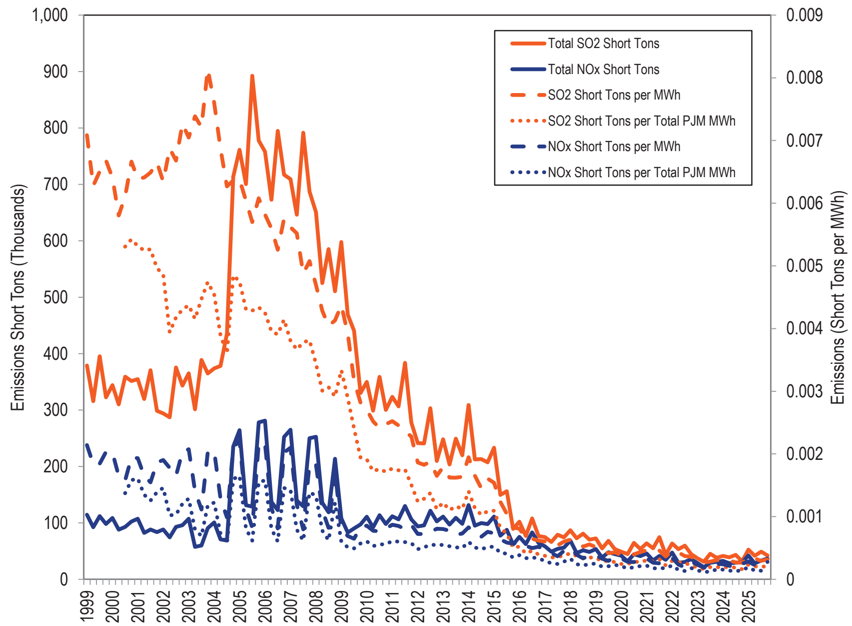
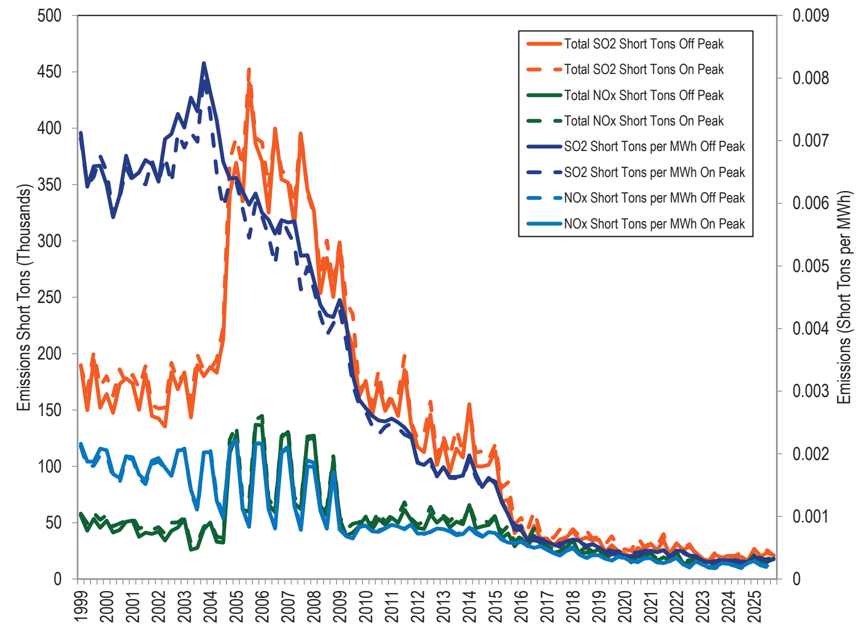


Figure 8-13 SO_2 and NO_x emissions during on and off peak hours by quarter (thousands of short tons), by PJM units: 1999 through 2025[316]



315 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

316 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

Table 8-33 Minimum and maximum SO_2 and NOx emissions per MWh: 1999 through 2025

Emission Type			Short Tons per MWh	Year	Quarter
SO2	Minimum	All hours	0.000	2024	4
		On Peak	0.000	2024	4
		Off Peak	0.000	2024	3
	Maximum	All hours	0.008	2003	4
		On Peak	0.008	2003	4
		Off Peak	0.008	2003	4
NOx	Minimum	All hours	0.000	2023	3
		On Peak	0.000	2023	2
		Off Peak	0.000	2023	3
	Maximum	All hours	0.002	2005	1
		On Peak	0.002	2005	1
		Off Peak	0.002	2005	1

Renewable Energy Output

Wind and Solar Peak Hour Output

Three different measures of capacity are applicable to wind and solar resources. The effective nameplate capacity is the maximum facility output (MFO).[317] [318] The installed capacity (ICAP) for wind and solar resources is equal to the lower of the effective nameplate and the capacity interconnection rights (CIRs).[319] The capacity measure for the PJM reliability requirement is unforced capacity (UCAP). The UCAP values for solar and wind resources are derated from the nameplate or installed capacity value based on expected performance during hours with high risk of loss of load (unserved energy). Until June 1, 2023, PJM used average unit performance over 360 summer peak hours to determine the derating factors. For the 2023/2024 Delivery Year, which began on June 1, 2023, PJM used an average ELCC approach to determine the capacity derating factor.[320] The average ELCC approach was also used for the 2024/2025 Delivery Year. Beginning with the 2025/2026 Delivery Year, PJM changed to a marginal ELCC approach.[321] [322]

317 *PJM Reliability Assurance Agreement*, Article 1.
318 MFO is defined in the *PJM Open Access Transmission Tariff*, Section I.1.
319 *PJM Manual 21: PJM Rules and Procedures for Determination of Generating Capability*, Section 6.1.1.
320 See Capacity Value of Intermittent Resources (ELCC) in *2024 Quarterly State of the Market Report for PJM: January through March*, Section 5: Capacity Market.
321 *Protest of the Independent Market Monitor for PJM*, ER24-99-000 (November 9, 2023).
322 Order 186 FERC ¶ 61,080 accepting PJM's marginal ELCC approach (January 30, 2024).

To illustrate the relationship between actual output, deliverable output and derating factors, Figure 8-14 shows wind and solar output and the three corresponding capacity measures, during the top 100 load hours in PJM in the first three months of 2026. Figure 8-15 shows wind and solar output for all hours in the first three months of 2026. In the first three months of 2026, 58 of the top 100 load hours in PJM are PJM defined peak load hours. The hours in Figure 8-14 are in descending order by load and the hours in Figure 8-15 are in chronological order. The solid lines represent the nameplate, ICAP and output of the wind or solar PJM resources. The dashed lines represent the derated capacity or UCAP for PJM wind and solar resources.

The actual output of the wind and solar resources during the top 100 load hours varied both above and below the ICAP and UCAP. Wind output was above the UCAP for 32 hours and below the UCAP for 68 hours of the top 100 load hours in the first three months of 2026. Wind output was above the ICAP for 34 hours and below the ICAP for 66 hours of the top 100 load hours in the first three months of 2026. The wind capacity factor for the top 100 load hours in the first three months of 2026 was 29.0 percent. Wind output was above the UCAP for 1,162 hours and below the UCAP for 997 hours in the first three months of 2026. Wind output was above the ICAP for 1,212 hours and below the ICAP for 947 hours in the first three months of 2026. The wind capacity factor in the first three months of 2026 was 38.4 percent.

Solar output was above the UCAP for 28 hours and below the UCAP for 72 hours of the top 100 load hours in the first three months of 2026. Solar output was above the ICAP for 4 hours and below the ICAP for 96 hours of the top 100 load hours in the first three months of 2026. The solar capacity factor for the top 100 load hours in the first three months of 2026 was 10.2 percent. Solar output was above the UCAP for 755 hours and below the UCAP for 1,404 hours in the first three months of 2026. Solar output was above the ICAP for 236 hours and below the ICAP for 1,923 hours in the first three months of 2026. The solar capacity factor in the first three months of 2026 was 15.5 percent.

Figure 8-14 Wind and solar output during the top 100 load hours: January through March, 2026[323]

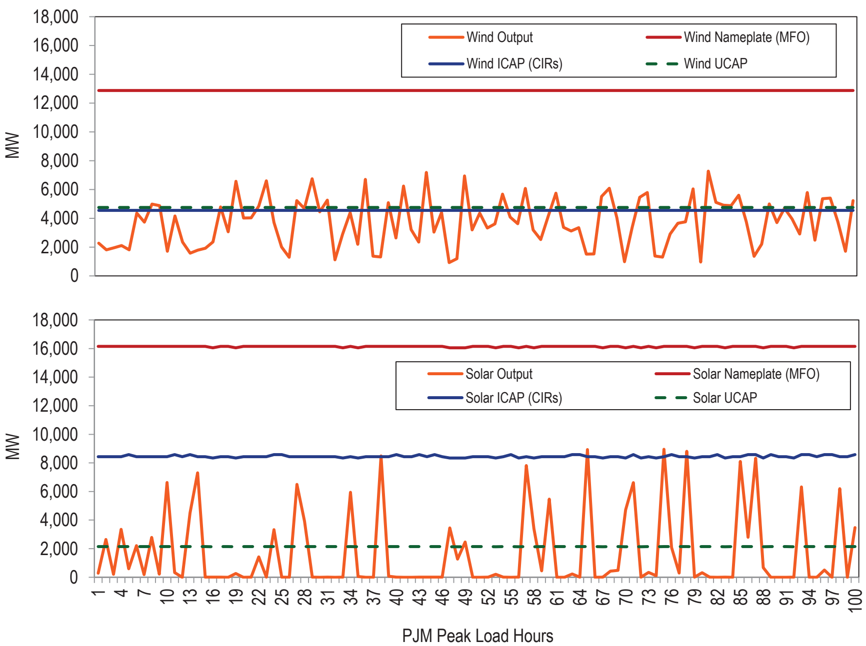


Figure 8-15 Wind and solar output: January through March, 2026[324]

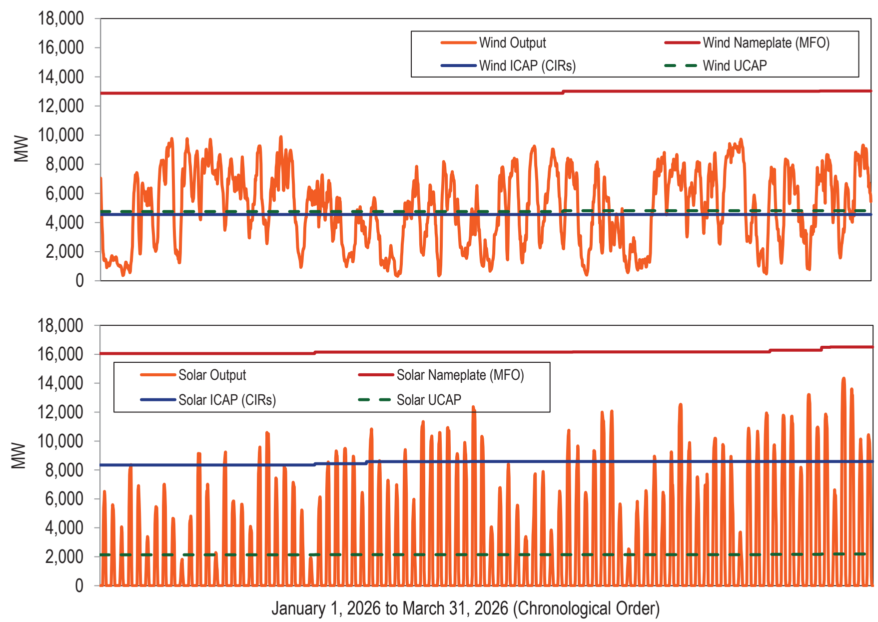


Figure 8-15 includes the impacts of the ELCC rules and winter CIR rules on the derated capacity values. The derated capacity for wind units includes winter CIRs. Winter CIRs are effective from November 1 through April 30 of the following year. The increases in the solar nameplate line and the wind nameplate line reflect new generators coming online.

Wind Units

Table 8-34 shows the capacity factors of wind units in PJM. In the first three months of 2026, the capacity factor of wind units in PJM was 38.6 percent. Wind units that were capacity resources had a capacity factor of 38.8 percent and an installed capacity of 11,867.4 MW. Wind units that were energy only had a capacity factor of 36.5 percent and an installed capacity of 1,081.5

323 The derated capacity (UCAP) includes energy only resources with the derating factors that would apply if the resources were capacity resources. The ICAP includes capacity resources only and represents the deliverable capacity.

324 The derated capacity (UCAP) includes energy only resources with the derating factors that would apply if the resources were capacity resources. The ICAP includes capacity resources only and represents the deliverable capacity

MW. Wind capacity resources were derated to 14.7 or 17.6 percent of installed capacity for the capacity market prior to June 1, 2023, based on the wind farm terrain. Beginning June 1, 2023, wind capacity is derated to the ELCC accredited UCAP value.[325]

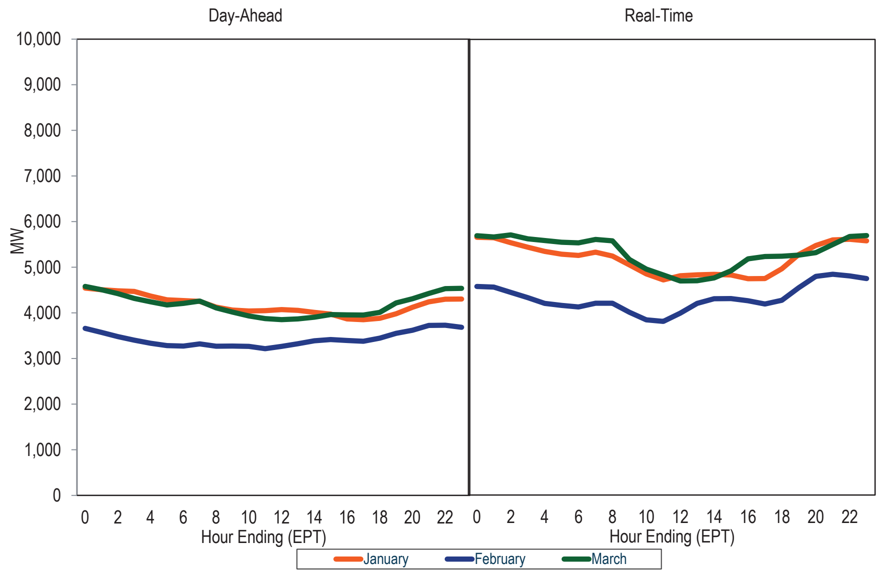
Table 8-34 Capacity factor of wind units: January through March, 2026

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	36.5%	1,081.5
Capacity Resource	38.6%	11,850.0
All Units	38.4%	12,931.5

Wind units that are capacity resources are required, like all capacity resources except demand resources, to offer the energy associated with their cleared capacity in the day-ahead energy market and in the real-time energy market. Figure 8-16 shows the average hourly real-time generation and day-ahead commitment of wind units in PJM, by month and hour of the day for the first three months of 2026. The hour with the highest average output in the first three months of 2026 was hour 3 in March with an average output of 5,709.4 MWh. The hour with the lowest average output in the first three months of 2026 was hour 12 in February with an average output of 3,811.1 MWh. Wind output in PJM is generally higher during off peak hours and lower during on peak hours. Wind output is generally highest during the months from November through March and lowest during the months from May through September.

Wind resources' day-ahead commitments are lower than real-time generation for most hours. Table 8-35 provides a summary of the deviations between wind resources' real-time generation and day-ahead commitments. In March 2026, hourly real-time generation exceeded day-ahead commitments by 1,146.4 MWh on average, the highest average monthly deviation in the first three months of 2026. The lowest monthly average deviation occurred in February with hourly real-time generation exceeding day-ahead commitments by 896.4 MWh on average. Wind generation exceeded day-ahead commitments in 85.4 percent of hours in the first three months of 2026. January and March both had 109 hours, 14.7 percent, with day-ahead commitments exceeding real-time generation.

Figure 8-16 Average hourly real-time generation and day-ahead commitments of wind units: January through March, 2026



325 ELCC rates and data are available on the PJM website <https://www.pjm.com/planning/resource-adequacy-planning/effective-load-carrying-capability>.

Table 8-35 Deviations between real-time wind generation and day-ahead commitments by month:[326] January through March, 2026

Month	Average Hourly Deviation	Minimum Hourly Deviation	Maximum Hourly Deviation	Hours with Negative Deviation
January	1,023.8	(2,045.1)	3,727.5	14.7%
February	896.4	(1,408.2)	3,318.0	14.4%
March	1,146.4	(1,432.1)	3,933.4	14.7%

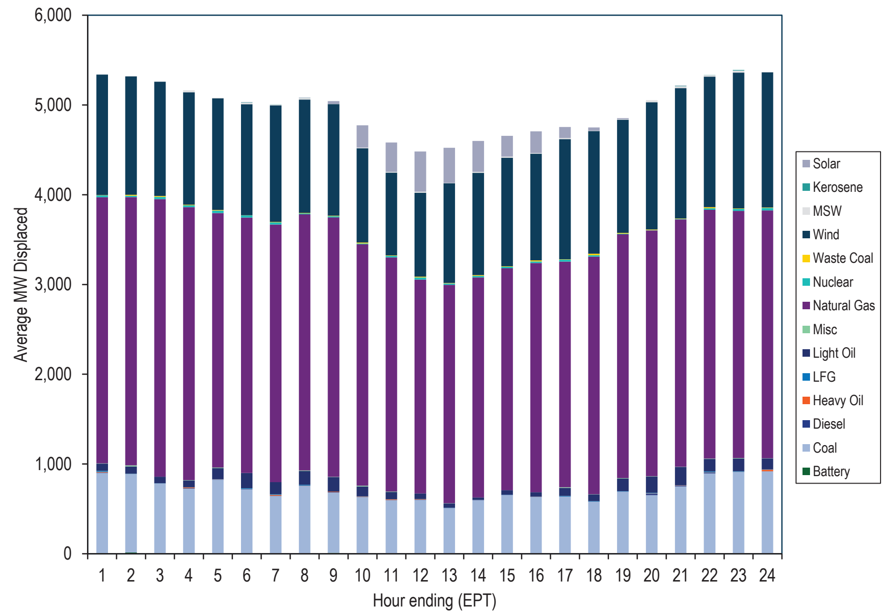
Table 8-36 shows the generation and capacity factor of wind units by month for 2025 and 2026.

Table 8-36 Capacity factor of wind units in PJM by month: January through March, 2025 and 2026

	2025		2026	
Month	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor
January	3,907.9	41.6%	3,865.8	40.4%
February	3,084.0	36.2%	2,906.7	33.5%
March	4,261.9	45.1%	3,951.6	40.9%

Output from wind turbines displaces output from other generation types because, in general, wind turbines generate power when the wind is blowing, regardless of the price. This displacement affects the output of marginal units in PJM. The magnitude and type of effect on marginal unit output depends on the level of wind turbine output, its location, time and duration. One measure of this displacement is based on the mix of marginal units when wind is producing output.[327] Figure 8-17 and Table 8-37 show the hourly average proportion of marginal units by fuel type mapped to the hourly average MW of real-time wind generation in the first three months of 2026. This is not an exact measure of displacement because it is not based on a redispatch of the system without wind resources. In the first three months of 2026, the SCED dispatch instruction for marginal wind resources was to reduce output for 60.2 percent of the marginal wind unit intervals. When wind appears as the displaced fuel at times when wind resources were on the margin this means that there was no displacement for those hours, if the dispatch instruction was to lower the generation. The level of wind displaced by wind is thus overstated by this metric.

Figure 8-17 Marginal fuel at time of wind generation: January through March, 2026



326 Hourly deviations are equal to the real-time generation less day-ahead commitments.
327 The measure is based on the principle that any incremental change in the wind output is balanced by the change in the output of marginal generators, while holding everything else equal.

Table 8-37 Marginal fuel MW at time of wind generation: January through March, 2026

Hour	Battery	Coal	Diesel	Heavy Oil	LFG	Light Oil	Misc	Natural Gas	Nuclear	Waste Coal	Wind	MSW	Kerosene	Solar	Total
0	6.5	893.5	6.0	6.7	10.7	79.5	3.6	2,965.4	21.4	3.7	1,342.3	0.0	0.0	0.0	5,339.2
1	14.5	873.4	0.0	2.0	3.2	78.8	13.5	2,988.0	16.1	10.9	1,317.7	5.5	0.0	0.0	5,323.5
2	5.7	777.2	1.6	0.0	1.3	73.5	0.0	3,092.1	24.8	9.3	1,272.9	0.0	0.0	0.0	5,258.4
3	6.4	718.4	5.5	8.3	3.3	75.5	3.7	3,040.6	20.7	7.2	1,252.1	21.6	0.0	0.0	5,163.2
4	0.0	823.8	3.2	1.9	2.2	121.7	7.2	2,835.9	27.6	6.4	1,243.7	7.8	0.0	0.0	5,081.4
5	0.0	716.5	3.8	0.9	9.0	169.3	0.0	2,845.5	24.6	2.4	1,235.8	18.0	3.0	3.4	5,029.0
6	0.0	643.1	2.7	11.1	7.0	134.8	0.0	2,869.2	23.8	5.7	1,297.7	9.8	1.3	0.0	5,006.1
7	0.0	755.0	0.8	1.8	10.9	151.4	7.8	2,853.5	11.8	4.0	1,263.3	17.2	1.5	3.4	5,079.0
8	9.9	672.2	5.5	4.5	0.8	161.0	2.7	2,891.1	13.3	4.9	1,244.2	2.2	0.0	30.3	5,012.4
9	2.5	627.8	1.4	3.8	4.4	110.6	7.1	2,690.5	9.6	9.1	1,051.9	6.1	0.0	249.0	4,524.6
10	0.0	595.2	3.8	7.1	0.0	80.9	5.4	2,608.7	17.6	5.1	923.6	8.4	0.0	325.8	4,255.6
11	0.0	599.8	3.4	4.7	1.2	62.3	0.0	2,382.3	25.3	8.8	934.8	11.6	0.0	447.1	4,034.3
12	2.1	506.3	2.5	0.0	2.7	48.4	0.7	2,433.1	15.4	4.5	1,112.4	2.4	0.0	393.4	4,130.5
13	3.5	591.8	2.5	0.0	1.3	28.2	0.0	2,451.7	16.1	9.8	1,137.8	11.8	0.0	344.7	4,254.6
14	3.9	649.5	3.3	0.0	1.7	49.8	0.0	2,471.7	17.5	6.5	1,209.4	11.7	0.0	230.8	4,425.0
15	0.0	633.9	1.3	0.6	2.0	47.0	0.0	2,553.7	18.2	12.0	1,188.7	6.4	0.0	243.1	4,463.9
16	2.1	634.9	0.0	0.8	7.3	89.6	6.8	2,514.1	22.2	3.7	1,338.7	11.6	0.0	122.8	4,631.8
17	3.9	577.1	0.9	0.3	5.9	73.0	2.2	2,647.7	15.6	17.1	1,365.4	3.4	0.0	37.5	4,712.3
18	0.0	690.4	3.6	0.0	3.1	140.0	5.5	2,715.9	7.7	8.3	1,261.3	6.0	0.0	10.8	4,841.8
19	5.9	647.8	14.9	3.2	6.4	182.7	2.1	2,738.9	3.9	6.7	1,418.8	21.2	0.0	0.0	5,052.6
20	0.0	749.6	9.2	2.5	1.5	205.0	1.9	2,754.6	6.3	4.7	1,452.6	21.0	5.8	3.5	5,214.6
21	0.0	894.0	10.3	3.4	9.6	140.3	2.4	2,772.4	16.1	12.9	1,455.1	16.2	3.2	0.0	5,335.8
22	0.0	911.1	0.0	1.5	7.2	141.2	5.4	2,753.9	21.9	5.5	1,513.5	23.0	6.1	0.0	5,390.3
23	0.0	917.6	2.2	15.7	4.3	122.1	2.1	2,761.3	27.2	5.7	1,506.9	3.5	0.0	0.0	5,368.5
Average	2.8	712.5	3.7	3.4	4.5	106.9	3.3	2,734.7	17.7	7.3	1,264.2	10.3	0.9	101.9	4,872.0

Solar Units

Solar units in PJM may be in front of or behind the meter. The data reported include all and only PJM solar units that are in front of the meter. As shown in Table 8-23, there are 18,043.1 MW of solar capacity registered in GATS that are PJM units. As shown in Table **8-24**, there are 15,236.1 MW capacity of solar registered in GATS that are not PJM units. Some behind the meter generation exists in clusters, such as community solar farms. The customers of these clusters may or may not be located at the same node on the transmission system as the solar farm. When behind the meter generation and its associated load are at separate nodes, loads should pay for the appropriate level of transmission service, and should not be permitted to avoid paying appropriate costs as a result of badly designed rules, such as rules for netting. The MMU recommends that load and generation located at separate nodes be treated as separate resources.

Table 8-38 shows the capacity factor of solar units in PJM. The capacity factor of solar units in PJM was 15.6 percent for the first three months of 2026. Solar units that were capacity resources had a capacity factor of 16.0 percent and an installed capacity of 14,489.2 MW. Solar units that were energy only had a capacity factor of 11.9 percent and an installed capacity of 1,549.0 MW. Solar capacity resources were derated to 38.0, 42.0 or 60.0 percent of installed capacity for the capacity market, prior to June 1, 2023, based on the installation type. Beginning June 1, 2023, solar capacity is derated to the ELCC accredited UCAP value.

Table 8-38 Capacity factor of solar units: January through March, 2026

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	11.8%	1,656.4
Capacity Resource	15.9%	14,501.8
All Units	15.5%	16,158.2

Solar units that are capacity resources are required, like all capacity resources except demand resources, to offer the energy associated with their cleared capacity in the day-ahead energy market and in the real-time energy market. Figure 8-18 shows the average real-time generation and day-ahead commitments of solar units in PJM, by month and hour of day.[328] The hour with the highest average output in the first three months of 2026, was hour 13 in March with an average of 9,233.3 MW. January had the lowest solar output in the first three months of 2026. The hour in December with the highest average output was hour 13 with an average of 6,274.2 MW. Solar output in PJM is generally higher during peak hours and lower during off peak hours. Solar output is generally highest during the months from May through August and lowest during the months from November through February.

Solar unit day-ahead commitments are lower than real-time generation for most hours between sunrise and sunset. Table 8-39 provides a summary of the deviations between solar unit real-time generation and day-ahead commitments. In January 2026, hourly real-time solar unit generation exceeded day-ahead solar unit commitments by 638.5 MWh on average, the highest average monthly deviation. The lowest monthly average deviation occurred in March with hourly real-time solar unit generation exceeding day-ahead commitments by 534.1 MWh on average. Solar generation exceeded day-ahead commitments in 67.3 percent of hours between sunrise and sunset in the first three months of 2026. March had the highest number of hours, 35.0 percent, with day-ahead commitments exceeding real-time generation.

328 The average day-ahead generation of solar units in PJM is greater than 0 for hours when the sun is down due to some solar units being paired with landfill units.

Figure 8-18 Average hourly real-time generation and day-ahead commitments of solar units: January through March, 2026

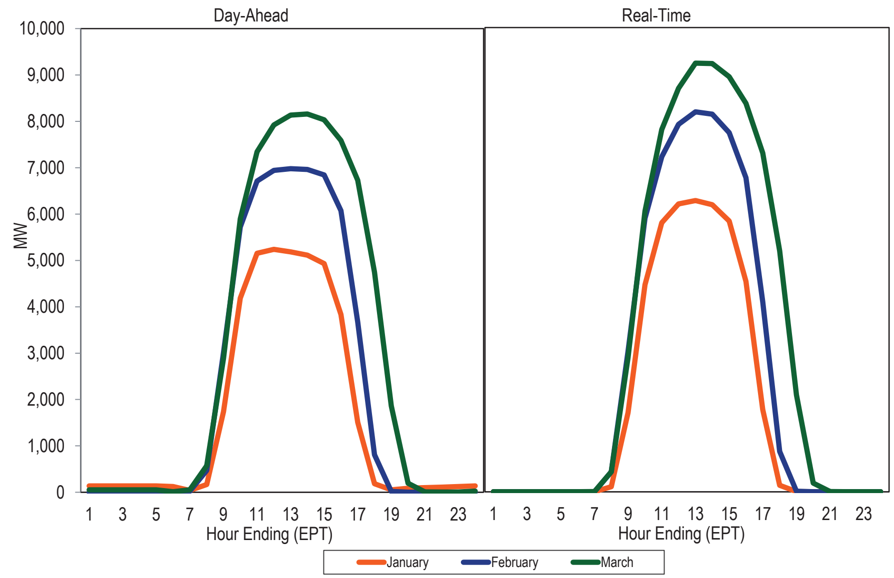


Table 8-39 Deviations between real-time solar generation and day-ahead commitments by month:[329] January through March, 2026

Month	Average Hourly Deviation	Minimum Hourly Deviation	Maximum Hourly Deviation	Hours with Negative Deviation
January	638.5	(1,365.9)	3,213.4	30.8%
February	544.1	(2,021.8)	3,150.2	31.8%
March	534.8	(3,552.9)	4,327.4	35.0%

329 Hourly deviations are equal to the real-time generation less day-ahead commitments.

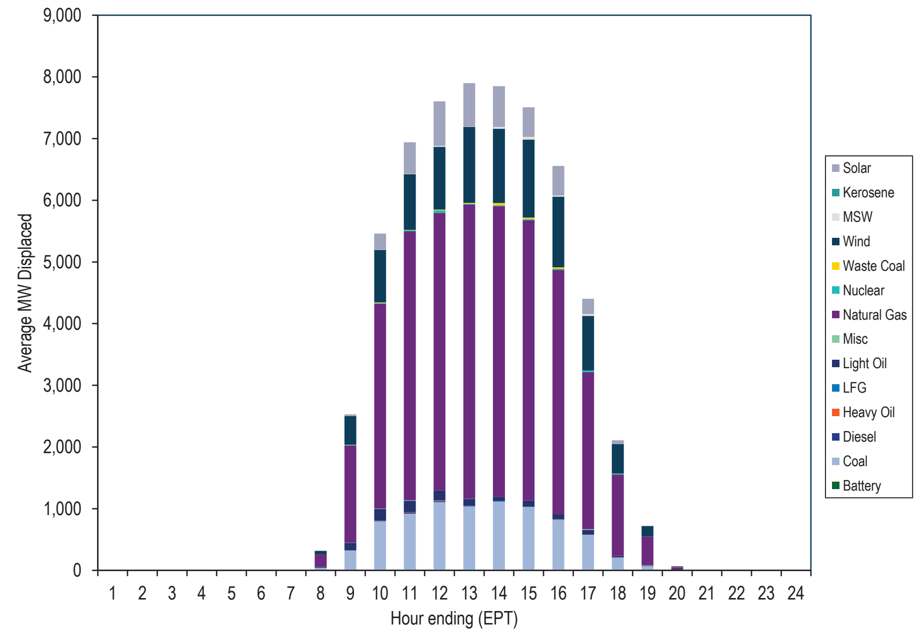
Table 8-40 shows the generation and capacity factor of solar units by month for 2025 and 2026.

Table 8-40 Capacity factor of solar units by month: January through March, 2025 and 2026

	2025		2026	
Month	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor
January	1,261.4	12.8%	1,334.6	11.2%
February	1,315.6	14.6%	1,686.2	15.5%
March	2,136.4	21.2%	2,371.0	19.6%

Output from solar generators displaces output from other generation types because, in general, solar photovoltaic cells generate power when the sun is shining, regardless of the price. This displacement affects the output of marginal units in PJM. The magnitude and type of effect on marginal unit output depends on the level of solar photovoltaic cell output, its location, time and duration. One measure of this displacement is based on the mix of marginal units when a solar unit is producing output.[330] Figure 8-19 and Table 8-41 show the hourly average proportion of marginal units by fuel type mapped to the hourly average MW of real-time solar generation in the first three months of 2026. This is not an exact measure of displacement because it is not based on a redispatch of the system without solar resources. In the first three months of 2026, the SCED dispatch instruction for marginal solar resources was to reduce output for 91.4 percent of the marginal solar unit intervals. When solar appears as the displaced fuel at times when solar resources were on the margin this means that there was no displacement for those hours, if the dispatch instruction was to lower the generation. The level of solar displaced by solar is thus overstated by this metric.

Figure 8-19 Marginal fuel at time of solar generation: January through March, 2026



330 The measure is based on the principle that any incremental change in the solar output is balanced by the change in the output of marginal generators, while holding everything else equal.

Table 8-41 Marginal fuel MW at time of solar generation: January through March, 2026

Hour	Battery	Coal	Diesel	Heavy Oil	LFG	Light Oil	Misc	Natural Gas	Nuclear	Waste Coal	Wind	MSW	Kerosene	Solar	Total
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	0.2
1	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	0.2
2	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	0.2
3	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	0.2
4	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	0.2
5	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	0.2
6	0.0	0.4	0.0	0.0	0.0	0.0	0.0	1.9	0.0	0.0	0.3	0.0	0.0	0.0	2.7
7	0.0	44.1	0.2	0.1	0.9	11.1	0.2	202.4	0.7	0.1	56.7	2.0	0.1	1.3	319.7
8	5.1	318.0	5.0	0.4	0.4	119.8	3.1	1,574.9	7.9	1.8	466.7	0.5	0.0	25.6	2,529.1
9	1.3	787.6	7.2	5.0	5.4	192.0	3.6	3,323.5	6.3	11.3	852.1	5.6	0.0	258.9	5,459.7
10	0.0	918.8	18.0	8.7	0.0	184.9	6.0	4,359.0	19.7	5.2	903.7	6.5	0.0	510.0	6,940.6
11	0.0	1,107.4	13.2	10.3	3.5	162.5	0.0	4,496.9	42.5	13.5	1,014.8	18.3	0.0	721.1	7,604.2
12	5.7	1,031.2	7.7	0.0	4.1	110.8	2.9	4,769.4	13.3	12.2	1,231.0	5.2	0.0	706.3	7,900.0
13	8.4	1,104.8	3.8	0.0	7.3	65.1	0.0	4,716.3	12.1	37.1	1,206.0	27.3	0.0	661.8	7,849.8
14	7.5	1,019.9	4.5	0.0	2.3	100.8	0.0	4,539.5	18.8	26.0	1,265.5	44.6	0.0	477.2	7,506.6
15	0.0	819.3	1.2	3.8	3.6	84.6	0.0	3,959.6	18.9	22.0	1,147.0	18.0	0.0	478.3	6,556.3
16	2.3	571.6	0.0	3.1	3.6	78.6	8.2	2,544.9	24.6	1.6	888.0	30.5	0.0	245.9	4,403.0
17	3.5	206.5	0.6	0.4	1.6	22.9	0.7	1,315.3	17.0	0.8	480.6	0.4	0.0	58.3	2,108.6
18	0.0	75.5	0.0	0.0	0.0	7.9	0.6	466.4	2.4	0.0	163.4	4.0	0.0	4.2	724.6
19	0.2	5.1	0.0	0.2	0.1	1.5	0.5	42.5	0.0	0.2	16.5	0.6	0.0	0.0	67.5
20	0.0	0.1	0.0	0.0	0.0	0.3	0.0	1.3	0.0	0.0	0.3	0.0	0.0	0.0	2.0
21	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.1	0.0	0.0	0.0	0.3
22	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	0.2
23	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	0.2
Average	1.4	333.8	2.6	1.3	1.4	47.6	1.1	1,513.1	7.7	5.5	403.9	6.8	0.0	172.9	2,499.0

9 Interchange Transactions

PJM market participants import energy from, and export energy to, external regions continuously. The transactions involved may fulfill long-term or short-term bilateral contracts or respond to price differentials. The external regions include both market and nonmarket balancing authorities.

Overview

Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Energy Market.** In the first three months of 2026, PJM was a monthly net exporter of energy in the real-time energy market in all months.[1] In the first three months of 2026, the real-time net interchange was -6,207.8 GWh. The real-time net interchange in the first three months of 2025 was -8,994.5 GWh.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** In the first three months of 2026, PJM was a monthly net exporter of energy in the day-ahead energy market in all months. In the first three months of 2026, the total day-ahead net interchange was -7,434.8 GWh. The day-ahead net interchange in the first three months of 2025 was -9,305.7 GWh.
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In the first three months of 2026, gross imports in the day-ahead energy market were 49.2 percent of gross imports in the real-time energy market (59.5 percent in the first three months of 2025). In the first three months of 2026, gross exports in the day-ahead energy market were 83.7 percent of the gross exports in the real-time energy market (88.3 percent in the first three months of 2025).
- **Interface Imports and Exports in the Real-Time Energy Market.** In the first three months of 2026, there were net scheduled exports at 11 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 2026, 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 2026, there were net scheduled exports at 12 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 2026, 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 2026, 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 2026, net scheduled interchange was -6,207.8 GWh and net actual interchange was -6,322.3 GWh, a difference of 114.6 GWh. In the first three months of 2025, the difference was 82.8 GWh. This difference is inadvertent interchange.
- **Loop Flows.** In the first three months of 2026, the Northern Indiana Public Service (NIPS) Interface had the largest loop flows of any interface with -148.2 GWh of net scheduled interchange and -3,582.4 GWh of net actual interchange, a difference of 3,434.1 GWh. In the first three months of 2026, the SOUTH interface pricing point had the largest loop flows of any interface pricing point with 3,130.2 GWh of net scheduled interchange and 5,256.1 GWh of net actual interchange, a difference of 2,125.9 GWh.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In the first three months of 2026, 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 53.2 percent of the hours.

1 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.

- **PJM and New York ISO Interface Prices.** In the first three months of 2026, 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 57.9 percent of the hours.

- **Neptune Underwater Transmission Line to Long Island, New York.** In the first three months of 2026, 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 84.4 percent of the hours.

- **Linden Variable Frequency Transformer (VFT) Facility.** In the first three months of 2026, 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 81.4 percent of the hours.

- **Hudson DC Line.** In the first three months of 2026, 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 74.1 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 2026, and two such TLRs in the first three months of 2025.
- **Up To Congestion.** The average number of up to congestion bids submitted in the day-ahead energy market increased by 17.0 percent, from 50,614 bids per day in the first three months of 2025 to 59,239 bids per day in the first three months of 2026. The average cleared volume of up to congestion bids submitted in the day-ahead energy market decreased by 25.8 percent, from 266,942 MWh per day in the first three months of 2025, to 197,997 MWh per day in the first three months of 2026.

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 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 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.)

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.

Interchange Transaction Activity

Charges and Credits Applied to Interchange Transactions

Interchange transactions are subject to various charges and credits. These charges and credits are dependent on whether the interchange transaction is submitted in the real-time or day-ahead energy market, the type of transaction, the transmission service used and whether the transaction is an import, export or wheel. Table 9-1 shows the billing line items that represent the charges and credits applied to real-time and day-ahead interchange transactions.[2]

Table 9-1 Charges and credits applied to interchange transactions

	Real-Time Transactions				Day-Ahead Transactions				
Billing Item	Import (Firm or Non Firm)	Import (Spot in)	Export	Wheel	Import (Firm or Non Firm)	Import (Spot in)	Export	Wheel	Up to Congestion
Firm or Non-Firm Point-to-Point Transmission Service	X		X[1]	X[1]	X		X[1]	X[1]	
Spot Import Service		X[2]				X[2]			
Day-ahead Spot Market Energy					X	X	X		
Balancing Spot Market Energy	X	X	X						
Day-ahead Transmission Congestion					X	X	X	X	X
Day-ahead Transmission Losses					X	X	X	X	X
Balancing Transmission Losses	X	X	X	X					X
PJM Scheduling, System Control and Dispatch Service - Control Area Administration	X		X	X	X		X	X	
PJM Scheduling, System Control and Dispatch Service - Market Support	X	X	X		X	X	X		X
PJM Scheduling, System Control and Dispatch Service - Advanced Second Control Center	X	X	X	X	X	X	X	X	X
PJM Scheduling, System Control and Dispatch Service - Market Support Offset	X	X	X		X	X	X		X
PJM Settlement, Inc.	X	X	X		X	X	X		X
Market Monitoring Unit (MMU) Funding	X	X	X		X	X	X		X
FERC Annual Recovery	X		X	X	X		X	X	
Organization of PJM States, Inc. (OPSI) Funding	X		X	X	X		X	X	
Synchronous Condensing			X				X		
Transmission Owner Scheduling, System Control and Dispatch Service	X		X	X	X		X	X	
Reactive Supply and Voltage Control from Generation and Other Sources Service	X		X	X	X		X	X	
Day-ahead Operating Reserve					X	X	X		X
Balancing Operating Reserve	X	X	X						X
Black Start Service	X		X	X	X		X	X	
Marginal Loss Surplus Allocation (for those paying for transmission service only)			X				X		

[1] No charge if Point of Delivery is MISO
[2] No charge for spot in transmission

2 For an explanation and current rate for each billing line item, see "*Quick Reference Guide to Market Settlements By Type of Business*" (February 1, 2023) <https://www.pjm.com/-/media/DotCom/training/core-curriculum/ip-ms-301/ms-301-quick-reference-guide-to-markets-settlements-by-type-of-business.pdf>.

Aggregate Imports and Exports

Table 9-2 shows the real-time and day-ahead scheduled interchange totals in the first three months of 2025 and 2026. In the first three months of 2026, gross imports in the day-ahead energy market were 49.2 percent of gross imports in the real-time energy market (59.5 percent in the first three months of 2025). In the first three months of 2026, gross exports in the day-ahead energy market were 83.7 percent of gross exports in the real-time energy market (88.3 percent in the first three months of 2025).

Table 9-2 Real-time and day-ahead scheduled interchange volumes (GWh): January through March, 2025 and 2026

Category	2025 (Jan - Mar)	2026 (Jan-Mar)	Percent Change
Real-Time Gross Imports	4,722.1	6,489.7	37.4%
Real-Time Gross Exports	13,716.6	12,697.4	(7.4%)
Real-Time Net Interchange	(8,994.5)	(6,207.8)	(31.0%)
Day-Ahead Gross Imports	2,809.9	3,192.2	13.6%
Day-Ahead Gross Exports	12,115.6	10,627.0	(12.3%)
Day-Ahead Net Interchange	(9,305.7)	(7,434.8)	(20.1%)
Monthly Average Real-Time Gross Exports	4,572.2	4,232.5	(7.4%)
Monthly Average Real-Time Gross Imports	1,574.0	2,163.2	37.4%
Monthly Average Day-Ahead Gross Exports	4,038.5	3,542.3	(12.3%)
Monthly Average Day-Ahead Gross Imports	936.6	1,064.1	13.6%

In the first three months of 2026, PJM was a monthly net exporter of energy in the real-time energy market in all months. In the first three months of 2026, PJM was a monthly net exporter of energy in the day-ahead energy market in all months (Figure 9-1).[3]

Figure 9-1 shows real-time and day-ahead import, export and net interchange volumes. The day-ahead totals include fixed, dispatchable and up to congestion transaction totals. The net interchange of up to congestion transactions are represented by the orange line.

Transactions in the day-ahead energy market create financial obligations to deliver in the real-time energy market and to pay operating reserve charges based on differences between the transaction MWh in the day-ahead and real-time energy markets times the applicable operating reserve rates. Up to congestion transactions also create financial obligations to deliver in real time, but did not pay operating reserve charges until November 1, 2020.

Figure 9-1 Scheduled imports and exports: January through March, 2026

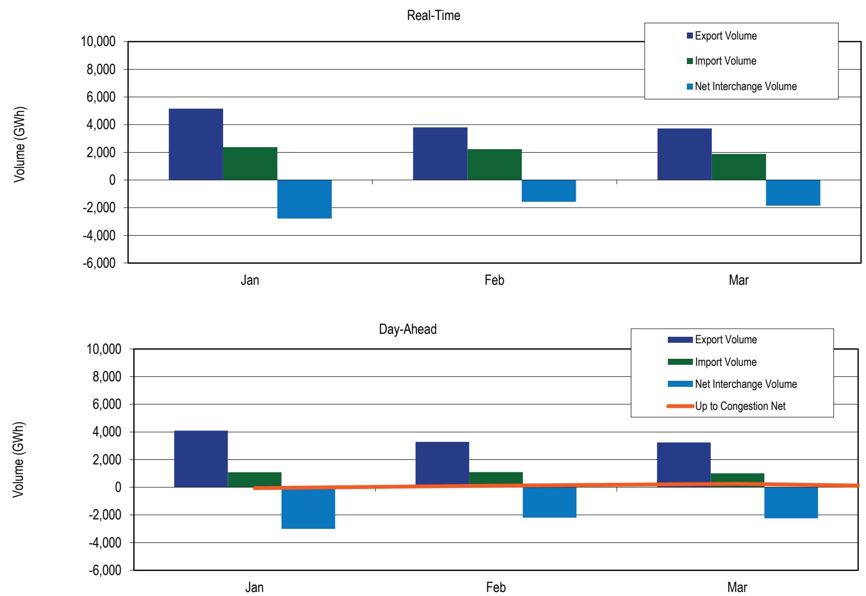


Figure 9-2 shows the real-time and day-ahead import and export volume for PJM from January 1999 through March 2026. PJM shifted from a consistent net importer of energy to relatively consistent net exporter of energy in 2004 in both the real-time and day-ahead energy markets, coincident with the expansion of the PJM footprint that included the integrations of Commonwealth Edison, American Electric Power and Dayton Power and Light into PJM. The net direction of power flows is generally expected to be a function of price differences net of transactions costs. Since the modification of the up to congestion product in September 2010, up to congestion transactions have played a significant role in power flows between PJM and external balancing

3 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.

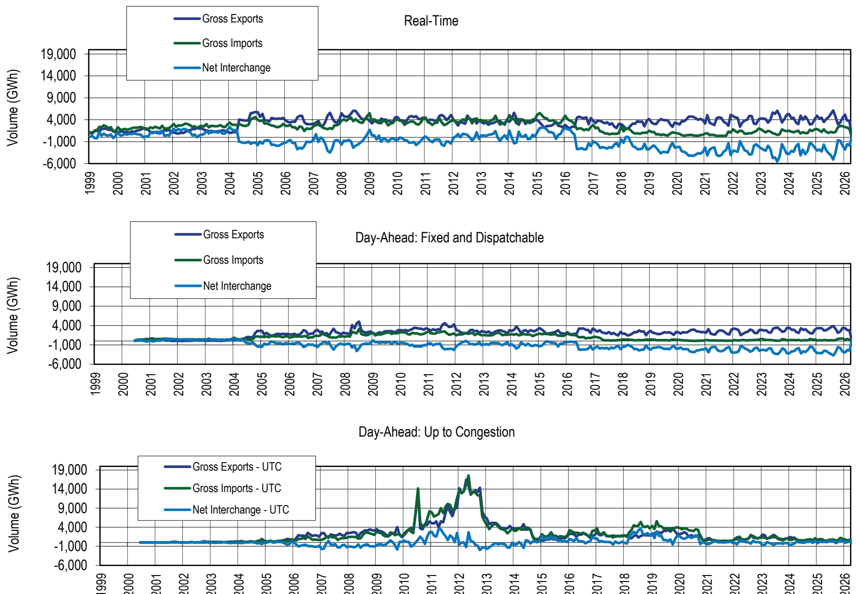
authorities in the day-ahead energy market. On November 1, 2012, PJM eliminated the requirement that every up to congestion transaction include an interface pricing point as either the source or sink. As a result, the volume of import and export up to congestion transactions decreased, and the volume of internal up to congestion transactions increased. While the gross import and export volumes in the day-ahead energy market decreased, PJM has remained primarily a net exporter in the day-ahead energy market. The requirement for external capacity resources to be pseudo tied into PJM has affected the real-time and day-ahead import volumes. Prior to June 1, 2016, these units were dynamically scheduled into PJM or were block scheduled into PJM and were part of scheduled interchange as imports. Pseudo tied units are treated as internal generation and therefore do not affect interchange volume. The reduction of the import volume based on the switch to pseudo tie status contributed to PJM remaining a net exporter in the real-time and day-ahead energy markets. On February 20, 2018, FERC issued an order limiting the eligible bidding points for up to congestion transactions to hubs, residual metered load and interfaces.[4] As a result, the volume of import and export up to congestion transactions increased, contributing to PJM becoming a net importer in the day-ahead energy market starting in March 2018. On July 16, 2020, FERC issued an order directing PJM to revise uplift allocation rules to allocate uplift to up to congestion transactions.[5] The Order requires PJM to treat an up to congestion transaction, for uplift allocation purposes, as if the up to congestion transaction were equivalent to a DEC at its sink point. On November 1, 2020, PJM began allocating uplift to up to congestion transactions. As a result, the volume of up to congestion transactions decreased, and PJM became a net exporter in the day-ahead energy market.

In February 2021, winter storms caused significant generation outages in Texas and resulted in power outages across the Electric Reliability Council of Texas (ERCOT) region. These outages occurred between February 10, 2021, and February 27, 2021. During this time, ERCOT imported generation from neighboring regions. While PJM did not have any scheduled exports directly to the ERCOT region, PJM exports during this time increased from an average hourly export of 4,772 MW per hour between February 1 and February 10, 2021, to 7,003 MW per hour between February 10 and February 27, 2021.

On June 13, 2022, PJM experienced several intervals of shortage pricing that resulted in high LMPs during the period from 1450 (EPT) through 1800 (EPT). PJM remained a net exporter of energy throughout the period despite the fact that PJM prices were much higher than MISO prices. PJM net exports averaged 4,431 MW during hours ending 1500 (EPT) through 1800 (EPT), a slight decrease from average net exports of 5,560 MW during the hours ending 1100 (EPT) through 1400 (EPT). Market participant response to the pricing signals in this period was affected by TLRs issued by MISO, SWPP and PJM, although the curtailments of scheduled imports to PJM were relatively small compared to the net exports. Export transactions to MISO continued to flow during this period primarily on firm and grandfathered transmission service. The lack of response to relative prices on the PJM/MISO interface was consistent with the ongoing pattern that there are net exports from PJM to MISO in almost every hour, regardless of relative prices. In the first three months of 2026, flows were in the uneconomic direction on the PJM/MISO interface in 46.8 percent of all hours.

4 See 162 FERC ¶ 61,139.
5 See 172 FERC ¶ 61,046.

Figure 9-2 Scheduled import and export transaction volume history: January 1, 1999 through March 31, 2026



Real-Time Interface Imports and Exports

In the real-time energy market, scheduled imports and exports are defined by the scheduled path, which is the transmission path a market participant selects from the original source to the final sink. These scheduled flows are measured at each of PJM's interfaces with neighboring balancing authorities. Table 9-19 includes a list of active interfaces in the first three months of 2026. Figure 9-3 shows the approximate geographic location of the interfaces. In the first three months of 2026, PJM had 19 interfaces with neighboring balancing authorities. While the Linden (LIND) Interface, the Hudson (HUDS) Interface and the Neptune (NEPT) Interface are separate from the NYIS Interface, all four are interfaces between PJM and the NYISO. There are 10 separate interfaces that make up the MISO Interface between PJM and MISO. Table 9-3 through Table 9-5 show the real-time energy market scheduled interchange totals at the individual NYISO interfaces, as well as with the NYISO as a whole. Similarly, the scheduled interchange totals at the individual interfaces between PJM and MISO are shown, as well as with MISO as a whole. Net scheduled interchange in the real-time energy market is shown by interface in the first three months of 2026 in Table 9-3, while gross scheduled imports and exports are shown in Table 9-4 and Table 9-5.

In the real-time energy market, in the first three months of 2026, there were net scheduled exports at 11 of PJM's 19 interfaces. The top three net exporting interfaces in the real-time energy market accounted for 69.0 percent of the total net scheduled exports: PJM/NYISO (NYIS) with 39.6 percent, PJM/Neptune (NEPT) with 15.0 percent and PJM/MidAmerican Energy Company (MEC) with 14.4 percent of the net scheduled export volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 71.5 percent of the total net PJM scheduled exports in the real-time energy market. There were net scheduled exports in the real-time energy market at five of the 10 separate interfaces that connect PJM to MISO. Those five exporting interfaces represented 24.1 percent of the total net PJM scheduled exports in the real-time energy market.

In the real-time energy market, in the first three months of 2026, there were net scheduled imports at seven of PJM's 19 interfaces. The top two importing interfaces in the real-time energy market accounted for 92.2 percent of the total net scheduled imports: PJM/Tennessee Valley Authority (TVA) with 64.1 percent and PJM/Duke (DUK) with 28.1 percent of the total net scheduled import volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) had net scheduled exports in the real-time energy market. There were net scheduled imports in the real-time energy market at four of the 10 separate interfaces that connect PJM to MISO. These importing interfaces represented 7.8 percent of the total net PJM scheduled imports in the real-time energy market.[6]

6 In the real-time energy market, one PJM interface had a net interchange of zero (PJM/City Water Light & Power (CWLP)). CWLP is a balancing authority on the western side of MISO.

Table 9-3 Real-time scheduled net interchange volume by interface (GWh): January through March, 2026

	Jan	Feb	Mar	Total
CPLE	(84.7)	(116.6)	29.3	(172.0)
CPLW	0.1	0.0	0.0	0.1
DUK	267.2	310.8	356.8	934.9
LGEE	(79.0)	(65.4)	(107.4)	(251.8)
MISO	(1,320.2)	(93.5)	(621.8)	(2,035.5)
ALTE	(105.2)	(0.0)	(31.0)	(136.2)
ALTW	(36.2)	37.8	55.7	57.4
AMIL	50.9	25.1	15.1	91.1
CIN	(491.5)	74.8	(130.7)	(547.4)
CWLP	0.0	0.0	0.0	0.0
IPL	53.2	29.6	11.6	94.3
MEC	(507.3)	(425.2)	(442.0)	(1,374.5)
MECS	(104.1)	117.2	3.0	16.1
NIPS	(72.1)	(25.1)	(51.0)	(148.2)
WEC	(108.0)	72.4	(52.4)	(88.0)
NYISO	(2,380.6)	(2,281.9)	(2,152.9)	(6,815.4)
HUDS	(440.9)	(361.8)	(156.0)	(958.7)
LIND	(224.1)	(206.4)	(220.4)	(651.0)
NEPT	(488.1)	(443.6)	(495.3)	(1,426.9)
NYIS	(1,227.5)	(1,270.1)	(1,281.3)	(3,778.9)
TVA	813.8	670.0	648.1	2,132.0
Total	(2,783.3)	(1,576.6)	(1,847.9)	(6,207.8)

Table 9-4 Real-time scheduled gross import volume by interface (GWh): January through March, 2026

	Jan	Feb	Mar	Total
CPLE	56.2	5.9	54.3	116.4
CPLW	0.1	0.0	0.0	0.1
DUK	381.6	421.3	392.2	1,195.0
LGEE	51.6	37.3	5.7	94.6
MISO	694.8	855.4	545.7	2,095.8
ALTE	10.1	35.0	23.6	68.7
ALTW	28.0	44.3	59.2	131.5
AMIL	66.2	37.4	35.7	139.4
CIN	203.1	244.3	70.1	517.6
CWLP	0.0	0.0	0.0	0.0
IPL	69.3	44.8	27.3	141.4
MEC	73.1	74.1	96.0	243.2
MECS	188.6	221.3	224.4	634.3
NIPS	(0.8)	16.8	2.1	18.1
WEC	57.2	137.2	7.2	201.6
NYISO	139.5	97.4	144.0	380.9
HUDS	0.0	0.1	0.0	0.1
LIND	1.5	0.0	0.0	1.5
NEPT	0.0	0.0	0.0	0.0
NYIS	137.9	97.2	144.0	379.2
TVA	1,052.4	813.7	740.7	2,606.8
Total	2,376.1	2,230.9	1,882.6	6,489.7

Table 9-5 Real-time scheduled gross export volume by interface (GWh): January through March, 2026

	Jan	Feb	Mar	Total
CPLE	140.9	122.5	25.1	288.4
CPLW	0.0	0.0	0.0	0.0
DUK	114.3	110.5	35.4	260.2
LGEE	130.6	102.7	113.1	346.4
MISO	2,014.9	948.9	1,167.6	4,131.4
ALTE	115.3	35.1	54.6	205.0
ALTW	64.2	6.5	3.5	74.2
AMIL	15.3	12.4	20.7	48.3
CIN	694.7	169.5	200.8	1,065.0
CWLP	0.0	0.0	0.0	0.0
IPL	16.1	15.3	15.7	47.1
MEC	580.4	499.3	538.0	1,617.7
MECS	292.6	104.1	221.5	618.2
NIPS	71.2	41.9	53.1	166.3
WEC	165.2	64.8	59.6	289.6
NYISO	2,520.0	2,379.3	2,296.9	7,196.3
HUDS	440.9	362.0	156.0	958.8
LIND	225.6	206.5	220.4	652.5
NEPT	488.1	443.6	495.3	1,426.9
NYIS	1,365.5	1,367.3	1,425.3	4,158.0
TVA	238.6	143.7	92.5	474.8
Total	5,159.4	3,807.5	3,730.5	12,697.4

Real-Time Interface Pricing Point Imports and Exports

Interfaces differ from interface pricing points. An interface is a point of interconnection between PJM and a neighboring balancing authority which market participants may designate as a path on which scheduled imports or exports will flow.[7] An interface pricing point defines the price at which transactions are priced, and is based on the path of the actual, physical transfer of energy. While a market participant designates a scheduled path from a generation control area (GCA) to a load control area (LCA), this path reflects the scheduled path as defined by the transmission reservations only, and may not reflect how the energy actually flows from the GCA to LCA. For example, the import transmission path from LG&E Energy, L.L.C. (LGEE), through MISO and into PJM would show the transfer of power into PJM at the PJM/MISO Interface based on the scheduled path of the transaction. However, the physical flow of energy does not enter the PJM footprint at the PJM/MISO Interface, but enters PJM at the southern boundary. For this reason, PJM prices an import with the GCA of LGEE at the SOUTH interface pricing point rather than the MISO pricing point.

Interfaces differ from interface pricing points. The challenge is to create interface prices, composed of external pricing points, which accurately represent the locational price impact of flows between PJM and external sources of energy and that reflect the underlying economic fundamentals across balancing authority borders.[8]

Transactions can be scheduled to an interface based on a contract transmission path, but pricing points are developed and applied based on the estimated electrical impact of the external power source on PJM tie lines, regardless of the contract transmission path.[9] PJM establishes prices for transactions with external balancing authorities by assigning interface pricing points to individual balancing authorities based on the generation control area and load control area as specified on the NERC Tag. Dynamic interface pricing calculations use actual system conditions to determine a set of weights for each external pricing point in an interface price definition. The weights are designed so that the interface price reflects actual system conditions. However, the weights are an approximation given the complexity of the transmission network outside PJM and the dynamic nature of power flows. Table 920 presents the interface pricing points used in the first three months of 2026. On October 21, 2020, PJM updated the mappings of external balancing authorities to individual pricing points. Figure 94 shows a map of the default interface pricing point assignments for all external balancing authorities. Figure 9-4 shows that the balancing authorities in the Western Interconnection are mapped to either the MISO interface pricing point or the SOUTH interface pricing point. This determination was made by PJM based on geographic location rather than the electrical impact on the PJM system. When power is scheduled across a DC tie line, its effects on the PJM system are as if a generator is located at the point in the Eastern Interconnection where the DC tie line connects. The electrical impact on PJM tie lines from sources in the Western Interconnection differ based on the relevant DC tie line and could vary from the MISO interface pricing point to the SOUTH interface pricing point. 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 rather than geographical location. The MMU recommends that PJM review the mappings of external balancing authority pricing points at least annually to reflect the fact that changes to the system topology can affect the electrical impact of external power sources on PJM.

The MMU has made multiple recommendations to either retire or consolidate interface pricing points used by PJM. The reasons for those recommendations include: pricing points that could no longer be used to price actual transactions; pricing points that were inappropriately used to support special agreements; pricing points that were treated as multiple pricing points when they were a single pricing point; and pricing points that were noncontiguous to the PJM footprint that created opportunities for sham scheduling. Table 96 shows the interface pricing points, the recommendation and the date the recommendation was adopted.

7 There are multiple paths between any generation and load balancing authority. Market participants select the path based on transmission service availability and the transmission costs for moving energy from generation to load and interface prices.

8 See the *2007 Annual State of the Market Report for PJM*, Volume 2, Appendix D, "Interchange Transactions," for a more complete discussion of the development of pricing points.

9 See "Interface Pricing Point Assignment Methodology," (May 7, 2025) <https://www.pjm.com/-/media/DotCom/etools/exschedule/interface-pricing-point-assignment-methodology.pdf>. PJM periodically updates these definitions on its website.

Table 9-6 MMU interface pricing point recommendations and dates adopted

Interface Pricing Point	Recommendation	Date Adopted
IMO	Retire Pricing Point - Noncontiguous	
Southeast (Real-Time Market)	Retire Pricing Point - Support Special Agreements	1-Oct-2022
Southwest (Real-Time Market)	Retire Pricing Point - Support Special Agreements	1-Oct-2022
SOUTHEXP	Consolidate Pricing Points	1-Jun-2021
SOUTHIMP	Consolidate Pricing Points	1-Jun-2021
Southeast	Retire Pricing Point - Support Special Agreements	15-Apr-2021
Southwest	Retire Pricing Point - Support Special Agreements	15-Apr-2021
NCMPAEXP	Retire Pricing Point - Preferential Treatment	3-Nov-2020
NCMPAIMP	Retire Pricing Point - Preferential Treatment	3-Nov-2020
Northwest	Retire Pricing Point - Noncontiguous	1-Oct-2020
CPLEEXP	Retire Pricing Point - Preferential Treatment	1-Jun-2020
CPLEIMP	Retire Pricing Point - Preferential Treatment	1-Jun-2020
DUKEXP	Retire Pricing Point - Preferential Treatment	1-Jun-2020
DUKIMP	Retire Pricing Point - Preferential Treatment	1-Jun-2020
NIPSCO	Retire Pricing Point - Obsolete (Integration into MISO)	1-Jun-2020
OVEC	Retire Pricing Point - Obsolete (Integration into PJM)	1-Dec-2018

The interface pricing method implies that the weighting factors reflect the actual system flows in a dynamic manner. In fact, the weightings are static, and are modified by PJM only occasionally.[10] The MMU recommended 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. At the March 20, 2024, meeting of the Markets and Reliability Committee, PJM stakeholders approved the implementation of a new annual review of interface pricing definitions.[11] [12] The annual review evaluates, and adjusts as necessary, the interface pricing definitions to ensure the buses and weightings used in the interface pricing definitions capture changes in system topology over time and reflect current system conditions.

The contract transmission path only reflects the path of energy into or out of PJM to one neighboring balancing authority. The NERC Tag requires the complete path to be specified from the generation control area (GCA) to the load control area (LCA), but participants do not always do so. The NERC Tag path is used by PJM to determine the interface pricing point that PJM assigns to the transaction. This approach will correctly identify the interface pricing point only if the market participant provides the complete path in the Tag.

In the real-time energy market, in the first three months of 2026, there were net scheduled exports at five of PJM's seven interface pricing points eligible for real-time transactions. The top three net exporting interface pricing points in the real-time energy market accounted for 83.3 percent of the total net scheduled exports: PJM/NYIS with 38.9 percent, PJM/MISO with 29.5 percent and PJM/NEPTUNE with 14.8 percent of the net scheduled export volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) together represented 70.5 percent of the total net PJM scheduled exports in the real-time energy market.

10 On June 1, 2015, PJM began using a dynamic weighting factor in the calculation for the Ontario interface pricing point.
11 *See* "Manual 11 Revisions – Interface Pricing Points Review," Presented at the PJM Markets and Reliability Committee (MRC) meeting held on March 20, 2024 <https://www.pjm.com/-/media/committees-groups/committees/mrc/2024/20240320/20240320-consent-agenda-b---1-manual-11-revisions-interface-pricing-points---presentation.ashx>.
12 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Rev. 136 (October 1, 2025).

In the real-time energy market, in the first three months of 2026, there were net scheduled imports at two of PJM's seven interface pricing points eligible for real-time transactions. The top importing interface pricing point in the real-time energy market was the PJM/SOUTH interface pricing point, which accounted for 92.0 percent of the total net scheduled import volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) had net scheduled exports in the real-time energy market.

Table 9-7 Real-time scheduled net interchange volume by interface pricing point (GWh): January through March, 2026

	Jan	Feb	Mar	Total
IMO	32.2	52.5	188.8	273.5
MISO	(1,557.5)	(451.9)	(829.5)	(2,838.9)
NYISO	(2,363.9)	(2,255.9)	(2,152.7)	(6,772.5)
HUDSONTP	(440.9)	(361.8)	(156.0)	(958.7)
LINDENVFT	(224.1)	(206.4)	(220.4)	(651.0)
NEPTUNE	(488.1)	(443.6)	(495.3)	(1,426.9)
NYIS	(1,210.8)	(1,244.1)	(1,281.1)	(3,736.0)
SOUTH	1,105.9	1,078.8	945.5	3,130.2
Total	(2,783.3)	(1,576.6)	(1,847.9)	(6,207.8)

Table 9-8 Real-time scheduled gross import volume by interface pricing point (GWh): January through March, 2026

	Jan	Feb	Mar	Total
IMO	111.6	86.4	200.6	398.6
MISO	376.1	459.8	318.4	1,154.3
NYISO	138.8	96.9	143.7	379.4
HUDSONTP	0.0	0.1	0.0	0.1
LINDENVFT	1.5	0.0	0.0	1.5
NEPTUNE	0.0	0.0	0.0	0.0
NYIS	137.3	96.7	143.7	377.7
SOUTH	1,749.6	1,587.8	1,219.9	4,557.3
Total	2,376.1	2,230.9	1,882.6	6,489.7

Table 9-9 Real-time scheduled gross export volume by interface pricing point (GWh): January through March, 2026

	Jan	Feb	Mar	Total
IMO	79.4	34.0	11.8	125.2
MISO	1,933.6	911.7	1,147.9	3,993.2
NYISO	2,502.6	2,352.9	2,296.4	7,151.9
HUDSONTP	440.9	362.0	156.0	958.8
LINDENVFT	225.6	206.5	220.4	652.5
NEPTUNE	488.1	443.6	495.3	1,426.9
NYIS	1,348.1	1,340.8	1,424.8	4,113.7
SOUTH	643.7	508.9	274.4	1,427.1
Total	5,159.4	3,807.5	3,730.5	12,697.4

Day-Ahead Interface Imports and Exports

In the day-ahead energy market, as in the real-time energy market, scheduled imports and exports are determined by the scheduled path, which is the transmission path a market participant selects from the original source to the final sink. Entering external energy transactions in the day-ahead energy market requires fewer steps than in the real-time energy market. Market participants need to acquire a valid, willing to pay congestion (WPC) OASIS reservation to prove that their day-ahead schedule could be supported in the real-time energy market.[13] Day-ahead energy market schedules need to be cleared through the day-ahead energy market process in order to become an approved schedule. The day-ahead energy market transactions are financially binding, but will not physically flow unless they are also submitted in the real-time energty market. In the day-ahead energy market, a market participant is not required to acquire a ramp reservation, a NERC Tag, or to go through a neighboring balancing authority checkout process.

There are three types of day-ahead external energy transactions: fixed; up to congestion; and dispatchable.[14]

13 Effective September 17, 2010, up to congestion transactions no longer required a willing to pay congestion transmission reservatio
14 See the *2010 Annual State of the Market Report for PJM*, Volume 2, Section 4, "Interchange Transactions," for details.

In the day-ahead energy market, transaction sources and sinks are determined solely by market participants. In Table 9-10, Table 9-11, and Table 9-12, the scheduled interface designation is determined by the transmission reservation that was acquired and associated with the day-ahead market transaction, and does not bear any necessary relationship to the pricing point designation selected at the time the transaction is submitted to PJM in real time. For example, if market participants want to import energy from the Southwest Power Pool (SPP) to PJM, they are likely to choose a scheduled path with the fewest transmission providers along the path and therefore the lowest transmission costs for the transaction, regardless of whether the resultant path is related to the physical flow of power. The lowest cost transmission path runs from SPP, through MISO, and into PJM, requiring only three transmission reservations, two of which are available at no cost (MISO transmission would be free based on the regional through and out rates, and the PJM transmission would be free, if using spot import transmission). Any other transmission path entering PJM, where the generating control area is to the south, would require the market participant to acquire transmission through nonmarket balancing authorities, and thus incur additional transmission costs. PJM's interface pricing method recognizes that transactions sourcing in SPP and sinking in PJM will create flows across the southern border and prices those transactions at the SOUTH interface price. As a result, a market participant who plans to submit a transaction from SPP to PJM may have a transmission reservation with a point of receipt of MISO and a point of delivery of PJM but may select SOUTH as the import pricing point when submitting the transaction in the day-ahead energy market. In the scheduled interface tables, the import transaction would appear as scheduled through the MISO Interface, and in the scheduled interface pricing point tables, the import transaction would appear as scheduled through the SOUTH interface pricing point, which reflects the expected power flow.

Table 9-10 through Table 9-12 show the day-ahead scheduled interchange totals at the individual interfaces. Net scheduled interchange in the day-ahead energy market is shown by interface for the first three months of 2026 in Table 9-10, while gross scheduled imports and exports are shown in Table 9-11 and Table 9-12.

In the day-ahead energy market, in the first three months of 2026, there were net scheduled exports at 12 of PJM's 19 interfaces. The top three net exporting interfaces in the day-ahead energy market accounted for 73.3 percent of the total net scheduled exports: PJM/NYISO (NYIS) with 38.8 percent, PJM/MidAmerican Energy Company (MEC) with 17.4 percent and PJM/Neptune (NEPT) with 17.1 percent of the net scheduled export volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 71.2 percent of the total net PJM scheduled exports in the day-ahead energy market. In the first three months of 2026, there were net exports in the day-ahead energy market at six of the 10 separate interfaces that connect PJM to MISO. Those six interfaces represented 24.2 percent of the total net PJM exports in the day-ahead energy market.

In the day-ahead energy market, in the first three months of 2026, there were net scheduled imports at five of PJM's 19 interfaces. The top importing interface in the day-ahead energy market was the Duke (DUK) Interface, which accounted for 55.7 percent of the net scheduled import volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) had net scheduled exports in the day-ahead energy market. In the first three months of 2026, there were net imports in the day-ahead energy market at three of the 10 separate interfaces that connect PJM to MISO. Those three interfaces represented 17.6 percent of the total net PJM imports in the day-ahead energy market.[15]

15 In the day-ahead energy market, two PJM interfaces had a net interchange of zero (PJM/Carolina Power and Light West (CPLW) and PJM/City Water Light & Power (CWLP)).

Table 9-10 Day-ahead scheduled net interchange volume by interface (GWh): January through March, 2026

	Jan	Feb	Mar	Total
CPLE	(24.8)	(17.3)	(13.7)	(55.7)
CPLW	0.0	0.0	0.0	0.0
DUK	102.3	87.7	72.5	262.6
LGEE	(122.5)	(97.2)	(103.3)	(323.0)
MISO	(885.8)	(412.4)	(610.9)	(1,909.1)
ALTE	(34.9)	(15.0)	(42.5)	(92.3)
ALTW	(30.5)	15.9	12.4	(2.2)
AMIL	0.0	0.0	1.6	1.6
CIN	(206.1)	(10.5)	(84.2)	(300.8)
CWLP	0.0	0.0	0.0	0.0
IPL	2.3	42.8	23.5	68.5
MEC	(515.3)	(446.0)	(471.5)	(1,432.8)
MECS	(37.3)	(19.4)	(13.3)	(70.0)
NIPS	0.0	12.7	0.3	13.0
WEC	(64.0)	7.1	(37.3)	(94.2)
NYISO	(1,997.3)	(1,928.0)	(1,923.3)	(5,848.6)
HUDS	(434.9)	(385.0)	(158.2)	(978.1)
LIND	(90.4)	(90.5)	(95.5)	(276.5)
NEPT	(451.7)	(449.7)	(502.3)	(1,403.6)
NYIS	(1,020.4)	(1,002.8)	(1,167.3)	(3,190.4)
TVA	(20.7)	53.5	92.8	125.6
Total without Up To Congestion	(2,948.7)	(2,313.7)	(2,485.9)	(7,748.3)
Up To Congestion	(59.3)	121.7	251.1	313.5
Total	(3,008.0)	(2,192.0)	(2,234.7)	(7,434.8)

Table 9-11 Day-ahead scheduled gross import volume by interface (GWh): January through March, 2026

	Jan	Feb	Mar	Total
CPLE	6.6	5.9	7.3	19.8
CPLW	0.0	0.0	0.0	0.0
DUK	150.8	112.0	78.1	340.9
LGEE	0.0	0.0	0.0	0.0
MISO	62.1	193.0	58.4	313.5
ALTE	1.1	10.9	1.5	13.5
ALTW	11.2	21.2	15.9	48.3
AMIL	0.0	0.0	1.6	1.6
CIN	19.1	49.5	8.9	77.5
CWLP	0.0	0.0	0.0	0.0
IPL	3.7	42.8	23.5	70.0
MEC	6.7	4.6	2.0	13.3
MECS	3.5	5.2	4.7	13.4
NIPS	0.0	13.3	0.3	13.6
WEC	16.8	45.4	0.0	62.3
NYISO	2.5	5.6	7.0	15.2
HUDS	0.0	0.0	0.0	0.0
LIND	0.7	0.0	0.0	0.7
NEPT	0.0	0.0	0.0	0.0
NYIS	1.9	5.6	7.0	14.5
TVA	145.9	179.7	171.5	497.1
Total without Up To Congestion	368.1	496.2	322.3	1,186.5
Up To Congestion	722.1	597.8	685.8	2,005.7
Total	1,090.2	1,094.0	1,008.0	3,192.2

Table 9-12 Day-ahead scheduled gross export volume by interface (GWh): January through March, 2026

	Jan	Feb	Mar	Total
CPLE	31.4	23.2	21.0	75.5
CPLW	0.0	0.0	0.0	0.0
DUK	48.5	24.3	5.6	78.3
LGEE	122.5	97.2	103.3	323.0
MISO	947.9	605.4	669.3	2,222.6
ALTE	36.0	25.9	43.9	105.8
ALTW	41.7	5.3	3.5	50.5
AMIL	0.0	0.0	0.0	0.0
CIN	225.1	60.0	93.2	378.3
CWLP	0.0	0.0	0.0	0.0
IPL	1.4	0.0	0.0	1.4
MEC	522.0	450.6	473.4	1,446.1
MECS	40.8	24.6	18.0	83.4
NIPS	0.0	0.6	0.0	0.6
WEC	80.8	38.4	37.3	156.5
NYISO	1,999.9	1,933.6	1,930.3	5,863.7
HUDS	434.9	385.0	158.2	978.1
LIND	91.1	90.5	95.5	277.1
NEPT	451.7	449.7	502.3	1,403.6
NYIS	1,022.2	1,008.4	1,174.3	3,204.9
TVA	166.6	126.2	78.8	371.6
Total without Up To Congestion	3,316.8	2,809.9	2,808.1	8,934.8
Up To Congestion	781.4	476.1	434.6	1,692.1
Total	4,098.2	3,286.0	3,242.8	10,627.0

Day-Ahead Interface Pricing Point Imports and Exports

Table 9-13 through Table 9-18 show the day-ahead scheduled interchange totals at the interface pricing points. In the first three months of 2026, up to congestion transactions accounted for 62.8 percent of all scheduled import MW transactions and 15.9 percent of all scheduled export MW transactions in the day-ahead energy market. The day-ahead net scheduled interchange in the first three months of 2026, including up to congestion transactions, is shown by interface pricing point in Table 9-13. Scheduled up to congestion transactions by interface pricing point in the first three months of 2026 are shown in Table 9-14. Day-ahead gross scheduled imports and exports, including up to congestion transactions, are shown in Table 9-15 and Table 9-17, while gross scheduled import and export up to congestion transactions are shown in Table 9-16 and Table 9-18.

Maintaining outdated definitions of interface pricing points is unnecessary, inconsistent with the tariff and creates artificial opportunities for gaming by virtual transactions and FTRs. PJM should immediately eliminate interface pricing points when changes to the market mean that the pricing points can no longer be used to price actual transactions and do not reflect actual price formation.

In the day-ahead energy market, in the first three months of 2026, there were net scheduled exports at six of PJM's seven interface pricing points eligible for day-ahead transactions. The top three net exporting interface pricing points in the day-ahead energy market accounted for 80.1 percent of the total net scheduled exports: PJM/NYIS with 39.5 percent, PJM/MISO with 25.6 percent and PJM/NEPTUNE (NEPT) with 15.0 percent of the net scheduled export volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) together represented 74.4 percent of the total net PJM scheduled exports in the day-ahead energy market.

In the day-ahead energy market, in the first three months of 2026, there were net scheduled imports at one of PJM's seven interface pricing points eligible for day-ahead transactions. The top importing interface pricing point in the day-ahead energy market was the PJM/SOUTH interface pricing point, which accounted for 100.0 percent of the net scheduled import volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) had net scheduled exports in the day-ahead energy market.

In the day-ahead energy market, in the first three months of 2026, up to congestion transactions had net scheduled exports at four of PJM's seven interface pricing points eligible for day-ahead transactions. The top two net exporting interface pricing points eligible for up to congestion transactions accounted for 58.9 percent of the total net up to congestion scheduled exports: PJM/HUDSONTP with 32.4 percent and PJM/LINDENVFT with 26.5 percent of the net up to congestion scheduled export volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) together represented 74.3 percent of the total net scheduled up to congestion exports in the day-ahead energy market. However, the PJM/NEPTUNE interface pricing point had net up to congestion scheduled imports in the day-ahead energy market.

In the day-ahead energy market, in the first three months of 2026, up to congestion transactions had net scheduled imports at three of PJM's seven interface pricing points eligible for day-ahead transactions. The top two importing interface pricing points eligible for up to congestion transactions accounted for 97.6 percent of the total up to congestion scheduled imports: PJM/SOUTH with 82.0 percent and PJM/NEPTUNE with 15.5 percent of the net up to congestion scheduled import volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) together represented 15.5 percent of the total net scheduled up to congestion imports in the day-ahead energy market. However, the PJM/HUDSONTP, PJM/LINDENVFT and PJM/NYIS interface pricing points had net up to congestion scheduled exports in the day-ahead energy market.

Table 9-13 Day-ahead scheduled net interchange volume by interface pricing point (GWh): January through March, 2026

	Jan	Feb	Mar	Total
IMO	0.0	7.2	(8.4)	(1.1)
MISO	(952.2)	(509.7)	(670.8)	(2,132.6)
NYISO	(2,198.6)	(1,990.5)	(2,003.9)	(6,193.0)
HUDSONTP	(533.5)	(475.2)	(190.3)	(1,199.0)
LINDENVFT	(184.0)	(154.6)	(118.4)	(457.0)
NEPTUNE	(363.6)	(401.1)	(484.5)	(1,249.2)
NYIS	(1,117.5)	(959.6)	(1,210.8)	(3,287.8)
SOUTH	142.7	300.9	448.3	891.9
Total	(3,008.0)	(2,192.0)	(2,234.7)	(7,434.8)

Table 9-14 Up to congestion scheduled net interchange volume by interface pricing point (GWh): January through March, 2026

	Jan	Feb	Mar	Total
IMO	23.6	13.6	(13.0)	24.2
MISO	(68.0)	(51.6)	(55.2)	(174.9)
NYISO	(201.9)	(69.4)	(80.6)	(352.0)
HUDSONTP	(98.6)	(90.2)	(32.1)	(220.8)
LINDENVFT	(93.6)	(64.1)	(22.9)	(180.5)
NEPTUNE	88.0	48.6	17.8	154.4
NYIS	(97.8)	36.3	(43.5)	(105.0)
SOUTH	187.1	229.1	400.0	816.2
Total Interfaces	(59.3)	121.7	251.1	313.5
INTERNAL	5,770.5	4,166.9	4,596.8	14,534.2
Total	5,711.2	4,288.6	4,847.9	14,847.7

Table 9-15 Day-ahead scheduled gross import volume by interface pricing point (GWh): January through March, 2026

	Jan	Feb	Mar	Total
IMO	62.5	27.0	25.4	115.0
MISO	274.5	236.2	194.1	704.7
NYISO	175.3	220.5	110.1	505.8
HUDSONTP	12.5	18.6	9.8	40.9
LINDENVFT	17.6	10.9	7.1	35.6
NEPTUNE	93.1	62.0	26.6	181.7
NYIS	52.0	128.9	66.6	247.5
SOUTH	577.9	610.3	678.5	1,866.7
Total	1,090.2	1,094.0	1,008.0	3,192.2

Table 9-16 Up to congestion scheduled gross import volume by interface pricing point (GWh): January through March, 2026

	Jan	Feb	Mar	Total
IMO	57.6	25.2	20.0	102.8
MISO	243.0	101.1	141.1	485.2
NYISO	172.7	214.8	103.1	490.7
HUDSONTP	12.5	18.6	9.8	40.9
LINDENVFT	17.0	10.9	7.1	35.0
NEPTUNE	93.1	62.0	26.6	181.7
NYIS	50.1	123.3	59.7	233.0
SOUTH	248.7	256.7	421.5	927.0
Total Interfaces	722.1	597.8	685.8	2,005.7

Table 9-17 Day-ahead scheduled gross export volume by interface pricing point (GWh): January through March, 2026

	Jan	Feb	Mar	Total
IMO	62.5	19.8	33.8	116.1
MISO	1,226.7	745.8	864.8	2,837.3
NYISO	2,373.8	2,210.9	2,114.0	6,698.8
HUDSONTP	546.0	493.8	200.1	1,239.9
LINDENVFT	201.6	165.5	125.5	492.6
NEPTUNE	456.7	463.1	511.1	1,430.9
NYIS	1,169.5	1,088.5	1,277.4	3,535.3
SOUTH	435.2	309.5	230.1	974.8
Total	4,098.2	3,286.0	3,242.8	10,627.0

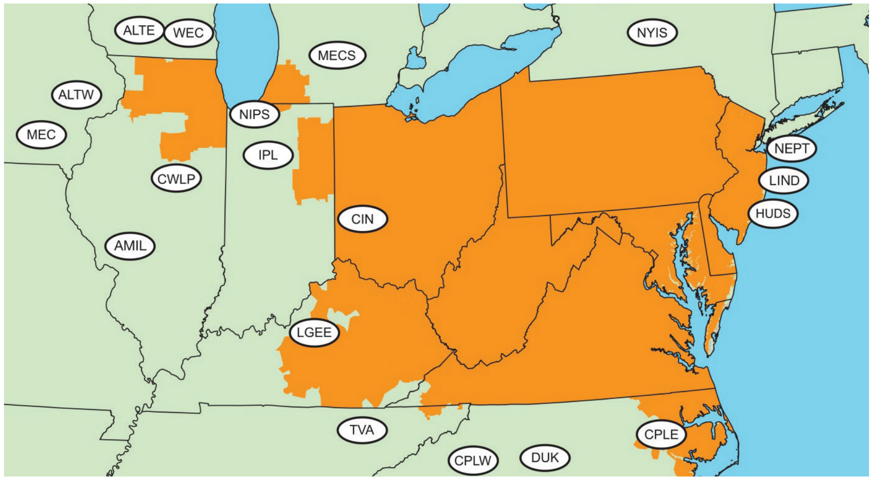
Table 9-18 Up to congestion scheduled gross export volume by interface pricing point (GWh): January through March, 2026

	Jan	Feb	Mar	Total
IMO	34.0	11.6	33.0	78.6
MISO	311.0	152.7	196.3	660.0
NYISO	374.7	284.2	183.7	842.6
HUDSONTP	111.1	108.8	41.9	261.7
LINDENVFT	110.6	75.0	29.9	215.5
NEPTUNE	5.1	13.4	8.8	27.3
NYIS	147.9	87.0	103.1	338.1
SOUTH	61.7	27.6	21.5	110.8
Total Interfaces	781.4	476.1	434.6	1,692.1

Table 9-19 Active scheduling interfaces: January through March, 2026[16]

	Jan	Feb	Mar
ALTE	Active	Active	Active
ALTW	Active	Active	Active
AMIL	Active	Active	Active
CIN	Active	Active	Active
CPLE	Active	Active	Active
CPLW	Active	Active	Active
CWLP	Active	Active	Active
DUK	Active	Active	Active
HUDS	Active	Active	Active
IPL	Active	Active	Active
LGEE	Active	Active	Active
LIND	Active	Active	Active
MEC	Active	Active	Active
MECS	Active	Active	Active
NEPT	Active	Active	Active
NIPS	Active	Active	Active
NYIS	Active	Active	Active
TVA	Active	Active	Active
WEC	Active	Active	Active

Figure 9-3 PJM's footprint and its external scheduling interfaces

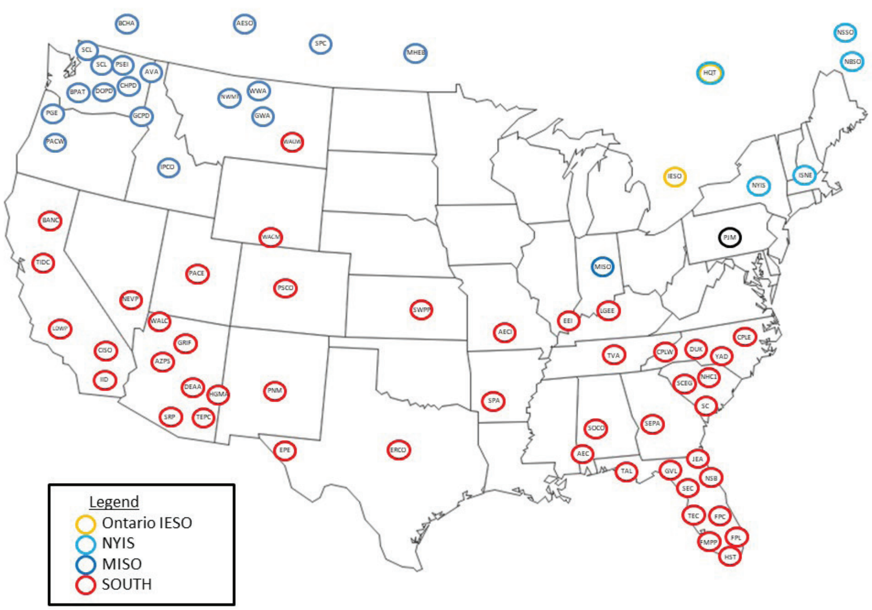


16 On July 2, 2012, Duke Energy Corp. (DUK) completed a merger with Progress Energy Inc. (CPLE and CPLW). As of March 31, 2026, DUK, CPLE and CPLW continued to operate as separate balancing authorities, and are still defined as distinct interfaces in the PJM energy market.

Table 9-20 Active scheduled interface pricing points: January through March, 2026

	Jan	Feb	Mar
HUDSONTP	Active	Active	Active
LINDENVFT	Active	Active	Active
MISO	Active	Active	Active
NEPTUNE	Active	Active	Active
NYIS	Active	Active	Active
Ontario IESO	Active	Active	Active
SOUTH	Active	Active	Active

Figure 9-4 External balancing authority default interface pricing point assignments



Loop Flows

Actual energy flows are the real-time metered power flows at an interface for a defined period. The comparable scheduled flows are the real-time power flows scheduled at an interface for a defined period. Inadvertent interchange is the difference between the total actual flows for the PJM system (net actual interchange) and the total scheduled flows for the PJM system (net scheduled interchange) for a defined period. Loop flows are the difference between actual and scheduled power flows at a specific interface. Loop flows can exist at the same time that inadvertent interchange is zero. For example, actual imports could exceed scheduled imports at one interface and actual exports could exceed scheduled exports at another interface by the same amount. The result is loop flow, despite the fact that system actual and scheduled power flow net to a zero difference.[17]

Loop flows result, in part, from a mismatch between incentives to use a particular scheduled transmission path and the market-based price differentials at interface pricing points that result from the actual physical flows on the transmission system.

PJM's approach to interface pricing attempts to match prices with physical power flows and their impacts on the transmission system. For example, if market participants want to import energy from the Southwest Power Pool (SPP) to PJM, they are likely to choose a scheduled path with the fewest transmission providers along the path and therefore the lowest transmission costs for the transaction, regardless of whether the resultant path is related to the physical flow of power. The lowest cost transmission path runs from SPP, through MISO, and into PJM, requiring only three transmission reservations, two of which are available at no cost (MISO transmission would be free based on the regional through and out rates, and the PJM transmission would be free, if using spot import transmission). Any other transmission path entering PJM, where the generating control area is to the south, would require the market participant to acquire transmission through nonmarket balancing authorities, and thus incur additional transmission costs. PJM's interface pricing method

17 See the *2012 Annual State of the Market Report for PJM*, Volume 2, Section 8, "Interchange Transactions," for a more detailed discussion.

recognizes that transactions sourcing in SPP and sinking in PJM will create flows across the southern border and prices those transactions at the SOUTH interface price. As a result, the transaction is priced appropriately, but a difference between scheduled and actual flows is created at PJM's borders. For example, if a 100 MW transaction were submitted, there would be 100 MW of scheduled flow at the PJM/MISO interface border, but there would be no actual flows on the interface. Correspondingly, there would be no scheduled flows at the PJM/SOUTH interface border, but there would be 100 MW of actual flows on the interface. In the first three months of 2026, of the 3,130.2 GWh of net scheduled interchange that received the SOUTH interface pricing point, 487.0 GWh (15.6 percent) were scheduled through MISO. There were no net scheduled flows across the southern interface that received the MISO interface pricing point.

In the first three months of 2026, net scheduled interchange was -6,207.8 GWh and net actual interchange was -6,322.3 GWh, a difference of 114.6 GWh. 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. This difference is inadvertent interchange. PJM attempts to minimize the amount of accumulated inadvertent interchange by continually monitoring and correcting for inadvertent interchange. PJM can reduce the accumulation of inadvertent interchange by using unilateral or bilateral paybacks. Inadvertent interchange accumulations that are paid back unilaterally are paid by controlling to a non-zero area control error (ACE). For example, Table 9-21 shows that PJM had 114.6 GW of inadvertent interchange in the first three months of 2026. To reduce this inadvertent interchange, PJM can control to an ACE less than zero, which would result in under generating. By way of the power balance equation, power would flow into PJM from its neighboring balancing authority areas. This would create decreased actual exports that were not scheduled, thus reducing the overall inadvertent. To maintain reliability, unilateral paybacks are accounted for in the control performance standard calculations. Bilateral paybacks are scheduled with other balancing authority areas by scheduling a correction and incorporating that amount as a bias in the energy management system.[18] [19]

Table 9-21 shows that in the first three months of 2026, the Northern Indiana Public Service (NIPS) Interface had the largest loop flows of any interface with -148.2 GWh of net scheduled interchange and -3,582.4 GWh of net actual interchange, a difference of 3,434.1 GWh.

Table 9-21 Net scheduled and actual PJM flows by interface (GWh): January through March, 2026

Interface	Actual	Net Scheduled	Difference (GWh)
CPLE	1,698.1	(172.0)	1,870.1
CPLW	(40.6)	0.1	(40.8)
DUK	506.4	934.9	(428.5)
LGEE	953.4	(251.8)	1,205.3
MISO	(4,734.7)	(2,035.5)	(2,699.1)
ALTE	(196.0)	(136.2)	(59.8)
ALTW	(858.5)	57.4	(915.9)
AMIL	1,407.8	91.1	1,316.7
CIN	(57.8)	(547.4)	489.6
CWLP	(93.5)	0.0	(93.5)
IPL	(370.7)	94.3	(465.0)
MEC	(1,503.4)	(1,374.5)	(128.9)
MECS	201.4	16.1	185.3
NIPS	(3,582.4)	(148.2)	(3,434.1)
WEC	318.4	(88.0)	406.5
NYISO	(6,843.7)	(6,815.4)	(28.3)
HUDS	(958.7)	(958.7)	0.0
LIND	(651.0)	(651.0)	0.0
NEPT	(1,426.9)	(1,426.9)	0.0
NYIS	(3,807.2)	(3,778.9)	(28.3)
TVA	2,138.8	2,132.0	6.8
Total	(6,322.3)	(6,207.8)	(114.6)

18 See PJM. "Manual 12: Balancing Operations," Rev. 56 (October 1, 2025).
19 PJM does not publish data on inadvertent payback.

Every external balancing authority is mapped to an import and export interface pricing point. The mapping is designed to reflect the physical flow of energy between PJM and each balancing authority. The net scheduled values for interface pricing points are defined as the MWh of scheduled transactions that will receive the interface pricing point based on the external balancing authority mapping.[20] For example, the MWh for a transaction whose transmission path is SPP through MISO and into PJM would be reflected in the SOUTH interface pricing point net schedule totals because SPP is mapped to the SOUTH interface pricing point. The actual flow on an interface pricing point is defined as the metered flow across the transmission lines that are included in the interface pricing point.

The differences between the scheduled MWh mapped to a specific interface pricing point and actual power flows at the interface pricing points provide a better measure of loop flows than differences at the interfaces. The scheduled transactions are mapped to interface pricing points based on the expected flow from the generation balancing authority and load balancing authority, whereas scheduled transactions are assigned to interfaces based solely on the OASIS path that the market participants reflect the transmission path into or out of PJM to one neighboring balancing authority. Power flows at the interface pricing points provide a more accurate reflection of where scheduled power flows actually enter or leave the PJM footprint based on the complete transaction path. Table 9-22 shows the net scheduled and actual PJM flows by interface pricing point.

The IMO interface pricing point with the Ontario IESO was created to reflect the fact that transactions that originate or sink in the Ontario Independent Electricity System Operator (IMO) balancing authority create physical flows that are split between the MISO and NYISO interface pricing points depending on transmission system conditions, so a mapping to a single interface pricing point does not reflect the actual flows. PJM created the IMO interface pricing point to reflect the actual power flows across both the MISO/PJM and NYISO/PJM Interfaces. The IMO does not have physical ties with PJM because it is not contiguous. Table 9-22 shows actual flows associated with the IMO interface pricing point as zero because there is no PJM/IMO Interface. The actual flows between IMO and PJM are included in the actual flows at the MISO and NYISO interface pricing points.

Table 9-22 shows that in the first three months of 2026, the SOUTH interface pricing point had the largest loop flows of any interface pricing point with 3,130.2 GWh of net scheduled interchange and 5,256.1 GWh of net actual interchange, a difference of 2,125.9 GWh.

Table 9-22 PJM flows by interface pricing point (GWh): January through March, 2026

Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)
IMO	0.0	273.5	(273.5)
MISO	(4,734.7)	(2,838.9)	(1,895.8)
NYISO	(6,843.7)	(6,772.5)	(71.2)
HUDSONTP	(958.7)	(958.7)	0.0
LINDENVFT	(651.0)	(651.0)	0.0
NEPTUNE	(1,426.9)	(1,426.9)	0.0
NYIS	(3,807.2)	(3,736.0)	(71.2)
SOUTH	5,256.1	3,130.2	2,125.9
Total	(6,322.3)	(6,207.8)	(114.6)

Table 9-23 shows the net scheduled and actual PJM flows by interface pricing point, with adjustments made to the MISO and NYISO scheduled interface pricing points based on the quantities of scheduled interchange where transactions from the IMO entered the PJM energy market.

Table 9-23 PJM flows by interface pricing point (GWh) (Adjusted for IMO Scheduled Interfaces): January through March, 2026

Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)
MISO	(4,734.7)	(2,522.6)	(2,212.1)
NYISO	(6,843.7)	(6,815.4)	(28.3)
HUDSONTP	(958.7)	(958.7)	0.0
LINDENVFT	(651.0)	(651.0)	0.0
NEPTUNE	(1,426.9)	(1,426.9)	0.0
NYIS	(3,807.2)	(3,778.9)	(28.3)
SOUTH	5,256.1	3,130.2	2,125.9
Total	(6,322.3)	(6,207.8)	(114.6)

20 The terms balancing authority and control area are used interchangeably in this section. The NERC Tag applications maintained the terminology of generation control area (GCA) and load control area (LCA) after the implementation of the NERC functional model. The NERC functional model classifies the balancing authority as a reliability service function, with, among other things, the responsibility for balancing generation, demand and interchange balance.

The NERC Tag requires the complete path to be specified from the generation control area (GCA) to the load control area (LCA), but participants do not always do so. The NERC Tag path is used by PJM to determine the interface pricing point that PJM assigns to the transaction. This approach will correctly identify the interface pricing point only if the market participant provides the complete path in the Tag. This approach will not correctly identify the interface pricing point if the market participant breaks the transaction into portions, each with a separate Tag. The breaking of transactions into portions can be a way to manipulate markets and the result of such behavior can be incorrect and noncompetitive pricing of transactions.

PJM attempts to ensure that external energy transactions are priced appropriately through the assignment of interface prices based on the expected actual flow from the generation balancing authority (source) and load balancing authority (sink) as specified on the NERC Tag. Assigning prices in this manner is a reasonable approach to ensuring that transactions receive or pay the PJM market value of the transaction based on expected flows, but this method does not address loop flow issues.

Loop flows remain a significant concern for the efficiency of the PJM market. Loop flows can have negative impacts on the efficiency of markets with explicit locational pricing, including impacts on locational prices, on FTR revenue adequacy and on system operations, and can be evidence of attempts to game the markets.

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 and receive higher prices (for imports) or lower prices (for exports) from PJM resulting from the inability to identify the true source or sink of the transaction. If all of the Northeast ISOs and RTOs implemented validation to prohibit the breaking of transactions into smaller segments, the level of Lake Erie loop flow would be reduced.

The MMU also 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.

Table 9-24 shows the net scheduled and actual PJM flows by interface and interface pricing point. This table shows the interface pricing points that were assigned to energy transactions that had paths at each of PJM's interfaces. For example, Table 9-24 shows that in the first three months of 2026, the majority of imports to the PJM energy market for which a market participant specified Michigan Electric Coordinated System (MECS) as the interface with PJM based on the scheduled transmission path, had a generation control area mapped to the IMO Interface, and thus actual flows were assigned the IMO interface pricing point (341.8 GWh). The majority of exports from the PJM energy market for which a market participant specified MECS as the interface with PJM based on the scheduled transmission path had a load control area for which the actual flows would leave the PJM energy market at the MISO Interface, and were assigned the MISO interface pricing point (-506.2 GWh).

Table 9-24 Net scheduled and actual flows by interface and interface pricing point (GWh): January through March, 2026

Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)
ALTE		(196.0)	(136.2)	(59.8)
	IMO	0.0	(0.1)	0.1
	MISO	(196.0)	(135.9)	(60.2)
	SOUTH	0.0	(0.3)	0.3
ALTW		(858.5)	57.4	(915.9)
	IMO	0.0	6.9	(6.9)
	MISO	(858.5)	49.1	(907.6)
	SOUTH	0.0	1.4	(1.4)
AMIL		1,407.8	91.1	1,316.7
	MISO	1,407.8	91.1	1,316.7
CIN		(57.8)	(547.4)	489.6
	IMO	0.0	(14.4)	14.4
	MISO	(57.8)	(582.8)	525.0
	SOUTH	0.0	49.8	(49.8)
CPLE		1,698.1	(172.0)	1,870.1
	SOUTH	1,698.1	(172.0)	1,870.1
CPLW		(40.6)	0.1	(40.8)
	SOUTH	(40.6)	0.1	(40.8)
CWLP		(93.5)	0.0	(93.5)
	MISO	(93.5)	0.0	(93.5)
DUK		506.4	934.9	(428.5)
	SOUTH	506.4	934.9	(428.5)
HUDS		(958.7)	(958.7)	0.0
	HUDSONTP	(958.7)	(958.7)	0.0
IPL		(370.7)	94.3	(465.0)
	IMO	0.0	(3.6)	3.6
	MISO	(370.7)	94.0	(464.7)
	SOUTH	0.0	3.9	(3.9)
LGEE		953.4	(251.8)	1,205.3
	SOUTH	953.4	(251.8)	1,205.3
LIND		(651.0)	(651.0)	0.0
	LINDENVFT	(651.0)	(651.0)	0.0
MEC		(1,503.4)	(1,374.5)	(128.9)
	IMO	0.0	(14.4)	14.4
	MISO	(1,503.4)	(1,418.5)	(84.8)
	SOUTH	0.0	58.4	(58.4)
MECS		201.4	16.1	185.3
	IMO	0.0	341.8	(341.8)
	MISO	201.4	(506.2)	707.6
	SOUTH	0.0	180.5	(180.5)
NEPT		(1,426.9)	(1,426.9)	0.0
	NEPTUNE	(1,426.9)	(1,426.9)	0.0
NIPS		(3,582.4)	(148.2)	(3,434.1)
	MISO	(3,582.4)	(148.3)	(3,434.1)
	SOUTH	0.0	0.0	(0.0)
NYIS		(3,807.2)	(3,778.9)	(28.3)
	IMO	0.0	(42.9)	42.9
	NYIS	(3,807.2)	(3,736.0)	(71.2)
TVA		2,138.8	2,132.0	6.8
	SOUTH	2,138.8	2,132.0	6.8
WEC		318.4	(88.0)	406.5
	MISO	318.4	(281.4)	599.8
	SOUTH	0.0	193.4	(193.4)
Grand Total		(6,322.3)	(6,207.8)	(114.6)

Table 9-25 shows the net scheduled and actual PJM flows by interface pricing point and interface. The grouping is reversed from Table 9-24. Table 9-25 shows the interfaces where transactions were scheduled which received the individual interface pricing points. For example, Table 9-25 shows that in the first three months of 2026, the majority of imports to the PJM energy market for which a market participant specified a generation control area for which it was assigned the SOUTH interface pricing point, had a path that entered the PJM energy market at the TVA Interface (2,132.0 GWh). The majority of exports from the PJM energy market for which a market participant specified a load control area for which it was assigned the SOUTH interface pricing point, had a path that would leave the PJM energy market at the LGEE Interface (-251.8 GWh).

Table 9-25 Net scheduled and actual flows by interface pricing point and interface (GWh): January through March, 2026

Interface Pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)
HUDSONTP		(958.7)	(958.7)	0.0
	HUDS	(958.7)	(958.7)	0.0
IMO		0.0	273.5	(273.5)
	ALTE	0.0	(0.1)	0.1
	ALTW	0.0	6.9	(6.9)
	CIN	0.0	(14.4)	14.4
	IPL	0.0	(3.6)	3.6
	MEC	0.0	(14.4)	14.4
	MECS	0.0	341.8	(341.8)
	NYIS	0.0	(42.9)	42.9
LINDENVFT		(651.0)	(651.0)	0.0
	LIND	(651.0)	(651.0)	0.0
MISO		(4,734.7)	(2,838.9)	(1,895.8)
	ALTE	(196.0)	(135.9)	(60.2)
	ALTW	(858.5)	49.1	(907.6)
	AMIL	1,407.8	91.1	1,316.7
	CIN	(57.8)	(582.8)	525.0
	CWLP	(93.5)	0.0	(93.5)
	IPL	(370.7)	94.0	(464.7)
	MEC	(1,503.4)	(1,418.5)	(84.8)
	MECS	201.4	(506.2)	707.6
	NIPS	(3,582.4)	(148.3)	(3,434.1)
	WEC	318.4	(281.4)	599.8
NEPTUNE		(1,426.9)	(1,426.9)	0.0
	NEPT	(1,426.9)	(1,426.9)	0.0
NYIS		(3,807.2)	(3,736.0)	(71.2)
	NYIS	(3,807.2)	(3,736.0)	(71.2)
SOUTH		5,256.1	3,130.2	2,125.9
	ALTE	0.0	(0.3)	0.3
	ALTW	0.0	1.4	(1.4)
	CIN	0.0	49.8	(49.8)
	CPLE	1,698.1	(172.0)	1,870.1
	CPLW	(40.6)	0.1	(40.8)
	DUK	506.4	934.9	(428.5)
	IPL	0.0	3.9	(3.9)
	LGEE	953.4	(251.8)	1,205.3
	MEC	0.0	58.4	(58.4)
	MECS	0.0	180.5	(180.5)
	NIPS	0.0	0.0	(0.0)
	TVA	2,138.8	2,132.0	6.8
	WEC	0.0	193.4	(193.4)
Grand Total		(6,322.3)	(6,207.8)	(114.6)

Data Required for Full Loop Flow Analysis

Loop flows are defined as the difference between actual and scheduled power flows at one or more specific interfaces. The differences between actual and scheduled power flows can be the result of a number of underlying causes. To adequately investigate the causes of loop flows, complete data are required.

Loop flows exist because electricity flows on the path of least resistance regardless of the path specified by contractual agreement or regulatory prescription. Loop flows can arise from transactions scheduled into, out of or around a balancing authority on contract paths that do not correspond to the actual physical paths on which energy flows. Outside of LMP-based energy markets, energy is scheduled and paid for based on contract path, without regard to the path of the actual energy flows. Loop flows can also result from actions within balancing authorities.

Loop flows are a significant concern. Loop flows can have negative impacts on the efficiency of markets with explicit locational pricing, including impacts on locational prices, on FTR revenue adequacy and on system operations, and can be evidence of attempts to game such markets. Loop flows also have poorly understood impacts on nonmarket areas. In general, the detailed sources of the identified differences between scheduled and actual flows remain unclear as a result of incomplete or inadequate access to the required data.

A complete analysis of loop flow could provide additional insight that could lead to enhanced overall market efficiency and clarify the interactions among market and nonmarket areas. A complete analysis of loop flow would improve the overall transparency of electricity transactions. There are areas with transparent markets, and there are areas with less transparent markets (nonmarket areas), but these areas together comprise a market, and overall market efficiency would benefit from the increased transparency that would derive from a better understanding of loop flows.

For a complete loop flow analysis, several types of data are required from all balancing authorities in the Eastern Interconnection. The Commission required access to NERC Tag data. In addition to the Tag data, actual tie line data, dynamic schedule and pseudo tie data are required in order to analyze the differences between actual and scheduled transactions. ACE data, market flow impact data and generation and load data are required in order to understand the sources, within each balancing authority, of loop flows that do not result from differences between actual and scheduled transactions.[21]

NERC Tag Data

An analysis of loop flow requires knowledge of the scheduled path of energy transactions. NERC Tag data include the scheduled path and energy profile of the transactions, including the Generation Control Area (GCA), the intermediate Control Areas, the Load Control Area (LCA) and the energy profile of all transactions. Complete tag data include the identity of the specific market participants. FERC Order No. 771 required access to NERC Tag data for the Commission, regional transmission organizations, independent system operators and market monitoring units.[22]

Actual Tie Line Flow Data

An analysis of loop flow requires knowledge of the actual path of energy transactions. Currently, a very limited set of tie line data is made available via the NERC IDC and the Central Repository for Curtailments (CRC) website. The available tie line data, and the data within the IDC, are presented as information on a screen, which does not permit analysis of the underlying data.

Dynamic Schedule and Pseudo Tie Data

Dynamic schedule and pseudo ties represent another type of interchange transaction between balancing authorities. While dynamic schedules are required to be tagged, the tagged profile is only an estimate of what energy is expected to flow. Dynamic schedules are implemented within each balancing authority's Energy Management System (EMS), with the current values shared over Inter-Control Center Protocol (ICCP) links. By definition, the dynamic schedule scheduled and actual values will always be identical from a balancing authority standpoint, and the tagged profile should be removed

21 It is requested that all data be made available in downloadable format in order to make analysis possible. A data viewing tool alone is not adequate.

22 See 141 FERC ¶ 61,235 (2012).

from the calculation of loop flows to eliminate double counting of the energy profile. Dynamic schedule data from all balancing authorities are required in order to account for all scheduled and actual flows.

Pseudo ties are similar to dynamic schedules in that they represent a transaction between balancing authorities and are handled within the EMS systems and data are shared over the ICCP. Pseudo ties differ from dynamic schedules in how the generating resource is modeled within the balancing authorities' ACE equations. Dynamic schedules are modeled as resources located in one area serving load in another, while pseudo ties are modeled as resources in one area moved to another area. Unlike dynamic schedules, pseudo tie transactions are not required to be tagged. Pseudo tie data from all balancing authorities are required in order to account for all scheduled and actual flows.

Area Control Error (ACE) Data

Area control error (ACE) data provides information about how well each balancing authority is matching their generation with their load. This information, combined with the scheduled and actual interchange values will show whether an individual balancing authority is pushing on or leaning on the interconnection, contributing to loop flows.

NERC makes real-time ACE graphs available on their Reliability Coordinator Information System (RCIS) website. This information is presented only in graphical form, and the underlying data is not available for analysis.

Market Flow Impact Data

In addition to interchange transactions, internal dispatch can also affect flows on balancing authorities' tie lines. The impact of internal dispatch on tie lines is called market flow. Market flow data are imported in the IDC, but there is only limited historical data, as only market flow data related to TLR levels 3 or higher are required to be made available via a Congestion Management Report (CMR). The remaining data are deleted.

There is currently a project in development through the NERC Operating Reliability Subcommittee (ORS) called the Market Flow Impact Tool. The purpose of this tool is to make visible the impacts of dispatch on loop flows. The MMU supports the development of this tool, but, equally important, requests that FERC and NERC ensure that the underlying data are provided to market monitors and other approved entities.

Generation and Load Data

Generation data (both real-time scheduled generation and actual output) and load data would permit analysis of the extent to which balancing authorities are meeting their commitments to serve load. If a balancing authority is not meeting its load commitment with adequate generation, the result is unscheduled flows across the interconnections to establish power balance.

Market areas are transparent in providing real-time load while nonmarket areas are not. For example, PJM posts real-time load via its eDATA application. Most nonmarket balancing authorities provide only the expected peak load on their individual websites. Data on generation are not made publicly available, as this is considered market sensitive information.

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.

PJM and MISO Interface Prices

Both the PJM/MISO and MISO/PJM interface pricing points represent the value of power at the relevant border, as determined in each market. In both cases, the interface price is the price at which transactions are settled. For example, a transaction into PJM from MISO would receive the PJM/MISO interface price upon entering PJM, while a transaction into MISO from PJM would receive the MISO/PJM interface price. PJM and MISO use network models to determine these prices and to attempt to ensure that the prices are consistent with the underlying electrical flows.

Under the PJM/MISO Joint Operating Agreement, the two RTOs mutually determine a set of transmission facilities on which both RTOs have an impact, and therefore jointly operate to those constraints. These jointly controlled facilities are M2M (Market to Market) flowgates. When a M2M constraint binds, PJM's LMP calculations at the buses that make up PJM's MISO interface pricing point are based on the PJM model's distribution factors of the selected buses to the binding M2M constraint and PJM's shadow price of the binding M2M constraint. MISO's LMP calculations at the buses that make up MISO's PJM interface pricing point are based on the MISO model's distribution factors of the selected buses to the binding M2M constraint and MISO's shadow price of the binding M2M constraint.

Prior to June 1, 2014, the PJM interface definition for MISO consisted of nine buses located near the middle of the MISO system and not at the border between the RTOs.[23] The interface definitions led to questions about the level of congestion included in interchange pricing.

PJM modified the definition of the PJM/MISO interface price effective June 1, 2014. PJM's new MISO interface pricing point includes 10 equally weighted buses that are close to the PJM/MISO border. The 10 buses were selected based on PJM's analysis that showed that over 80 percent of the hourly tie line flows between PJM and MISO occurred on 10 ties composed of MISO and PJM monitored facilities. On June 1, 2017, MISO modified their MISO/PJM interface definition to match PJM's PJM/MISO interface definition.

Real-Time and Day-Ahead PJM/MISO Interface Prices

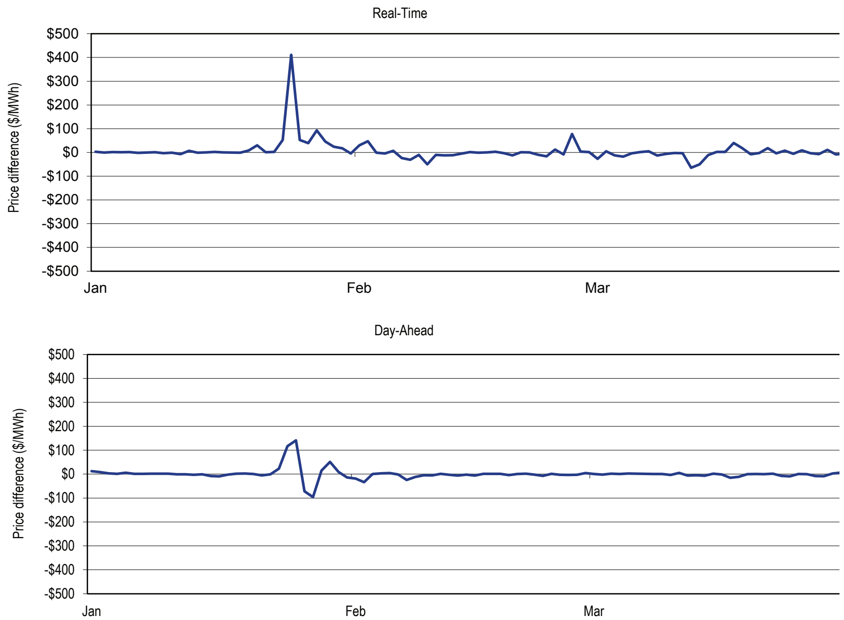
In the first three months of 2026, the direction of flow was consistent with price differentials in 53.2 percent of the hours. Table 9-26 shows the number of hours and average hourly price differences between the PJM/MISO Interface and the MISO/PJM Interface based on LMP differences and flow direction. Table 9-26 shows that PJM was a net exporter of energy to MISO in all but 83 hours during the first three months of 2026. The lack of response to relative prices on the PJM/MISO interface was consistent with the ongoing pattern that there are net exports from PJM to MISO in almost every hour, regardless of relative prices. In the first three months of 2026, flows were in the uneconomic direction on the PJM/MISO interface in 46.8 percent of all hours. Figure 9-5 shows the underlying variability in prices calculated on a daily hourly average basis. There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences (Table 9-30).

Table 9-26 PJM and MISO flow based hours and price differences: January through March, 2026

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
MISO/PJM LMP > PJM/MISO LMP	Total Hours	1,127	$31.57
	Consistent Flow (PJM to MISO)	1,096	$31.20
	Inconsistent Flow (MISO to PJM)	31	$44.67
	No Flow	0	$0.00
PJM/MISO LMP > MISO/PJM LMP	Total Hours	1,032	$20.07
	Consistent Flow (MISO to PJM)	52	$49.57
	Inconsistent Flow (PJM to MISO)	980	$18.50
	No Flow	1	$47.77

23 See "LMP Aggregate Definitions," (March 11, 2026) <https://www.pjm.com/-/media/DotCom/markets-ops/energy/lmp-model-info/lmp-aggregate-definitions.xlsx>. PJM periodically updates these definitions on its website. See <http://www.pjm.com>.

Figure 9-5 Price differences (MISO/PJM Interface minus PJM/MISO Interface): January through March, 2026



Distribution and Prices of Hourly Flows at the PJM/MISO Interface

Almost without exception, power flows from PJM to MISO regardless of the direction of price differences. In the first three months of 2026, the direction of hourly energy flows was consistent with PJM and MISO interface price differentials in 1,148 hours (53.2 percent of all hours), and was inconsistent with price differentials in 1,011 hours (46.8 percent of all hours). Table 9-27 shows the distribution of hourly energy flows between PJM and MISO based on the price differences between the PJM/MISO and MISO/PJM prices. Of the 1,011 hours where flows were in a direction inconsistent with price differences, 906 of those hours (89.6 percent) had a price difference greater than or equal to $1.00 and 616 of those hours (60.9 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $1,075.54. Of the 1,148 hours where flows were consistent with price differences, 1,038 of those hours (90.4 percent) had a price difference greater than or equal to $1.00 and 626 of all such hours (54.5 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $1,705.41.

Table 9-27 Distribution of hourly flows that are consistent and inconsistent with price differences between PJM and MISO: January through March, 2026

Price Difference Range (Greater Than or Equal To)	Inconsistent Hours	Percent of Inconsistent Hours	Consistent Hours	Percent of Consistent Hours
$0.00	1,011	100.0%	1,148	100.0%
$1.00	906	89.6%	1,038	90.4%
$5.00	616	60.9%	626	54.5%
$10.00	409	40.5%	389	33.9%
$15.00	309	30.6%	305	26.6%
$20.00	237	23.4%	268	23.3%
$25.00	194	19.2%	224	19.5%
$50.00	84	8.3%	135	11.8%
$75.00	42	4.2%	98	8.5%
$100.00	26	2.6%	67	5.8%
$200.00	6	0.6%	30	2.6%
$300.00	3	0.3%	18	1.6%
$400.00	3	0.3%	14	1.2%
$500.00	3	0.3%	11	1.0%

PJM and NYISO Interface Prices

If interface prices were defined in a comparable manner by PJM and the NYISO, if identical rules governed external transactions in PJM and the NYISO, if time lags were not built into the rules governing such transactions and if no risks were associated with such transactions, then prices at the interfaces would be expected to be very close and the level of transactions would be expected to be related to any price differentials. The fact that none of these conditions exists is important in explaining the observed relationship between interface prices and inter-RTO/ISO power flows, and those price differentials.[24]

24 See the *2012 Annual State of the Market Report for PJM*, Volume 2, Section 8, "Interchange Transactions," for a more detailed discussion.

PJM and NYISO each calculate an interface LMP using network models including distribution factor impacts. On May 1, 2017, PJM modified the PJM/NYIS interface price to be based on four buses within NYISO. The four buses were chosen based on a power flow analysis of transfers between PJM and the NYISO and the resultant distribution of flows across the free flowing A/C ties.

Prior to May 1, 2017, PJM's PJM/NYIS interface definition used two buses and included the impact of the ConEd wheeling agreement. The ConEd wheeling agreement ended on May 1, 2017. The end of the wheeling agreement meant that the expected actual power flows would change and therefore the definition of the interface price needed to change.

The NYISO uses proxy buses to calculate interface prices with neighboring balancing authorities. A proxy bus is a single bus, located outside the NYISO footprint, which represents generation and load in a neighboring balancing authority area. The NYISO models imports from PJM as generation at the Keystone proxy bus, delivered to the NYISO reference bus with the assumption that 32 percent of the flow will enter the NYISO across the free flowing A/C ties, 32 percent will enter the NYISO across the Ramapo PARs, 21 percent will enter the NYISO across the ABC PARs and 15 percent will enter the NYISO across the J/K PARs. The NYISO models exports to PJM as being delivered to load at the Keystone proxy bus, sourced from the NYISO reference bus with the assumption that 32 percent of the flow will enter PJM across the free flowing A/C ties, 32 percent will enter PJM across the Ramapo PARs, 21 percent will enter PJM across the ABC PARs and 15 percent will enter PJM across the J/K PARs.

Real-Time and Day-Ahead PJM/NYISO Interface Prices

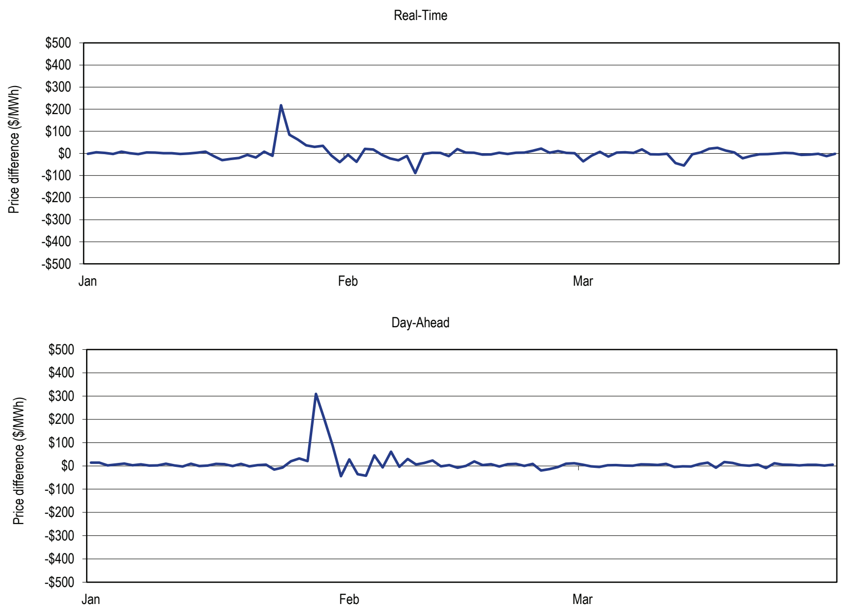
In the first three months of 2026, the relationship between prices at the PJM/NYIS Interface and at the NYISO/PJM proxy bus and the relationship between interface price differentials and power flows continued to be affected by differences in institutional and operating practices between PJM and the NYISO. The direction of flow was consistent with price differentials in 57.9 percent of the hours in the first three months of 2026. Table 9-28 shows the number of hours and average hourly price differences between the PJM/NYIS Interface and the NYIS/PJM proxy bus based on LMP differences and flow direction. Figure 9-6 shows the underlying variability in prices calculated on a daily hourly average basis. There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences (Table 9-30).

Table 9-28 PJM and NYISO flow based hours and price differences: January through March, 2026[25]

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/PJM proxy bus LBMP > PJM/NYIS LMP	Total Hours	1,249	$28.77
	Consistent Flow (PJM to NYIS)	1,249	$28.77
	Inconsistent Flow (NYIS to PJM)	0	$0.00
	No Flow	0	$0.00
PJM/NYIS LMP > NYIS/PJM proxy bus LBMP	Total Hours	910	$37.33
	Consistent Flow (NYIS to PJM)	0	$0.00
	Inconsistent Flow (PJM to NYIS)	910	$37.33
	No Flow	0	$0.00

25 The NYISO Locational Based Marginal Price (LBMP) is the equivalent term to PJM's Locational Marginal Price (LMP).

Figure 9-6 Price differences (NY/PJM proxy – PJM/NYIS Interface): January through March, 2026



Distribution and Prices of Hourly Flows at the PJM/NYISO Interface

In the first three months of 2026, the direction of hourly energy flows was consistent with PJM/NYISO and NYISO/PJM price differences in 1,249 hours (57.9 percent of all hours), and was inconsistent with price differences in 910 hours (42.1 percent of all hours). Table 9-29 shows the distribution of hourly energy flows between PJM and NYISO based on the price differences between the PJM/NYISO and NYISO/PJM prices. Of the 910 hours where flows were in a direction inconsistent with price differences, 873 of those hours (95.9 percent) had a price difference greater than or equal to $1.00 and 716 of all those hours (78.7 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $1,160.39. Of the 1,249 hours where flows were consistent with price differences, 1,193 of those hours (95.5 percent) had a price difference greater than or equal to $1.00 and 989 of all such hours (79.2 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $1,460.34.

Table 9-29 Distribution of hourly flows that are consistent and inconsistent with price differences between PJM and NYISO: January through March, 2026

Price Difference Range (Greater Than or Equal To)	Inconsistent Hours	Percent of Inconsistent Hours	Consistent Hours	Percent of Consistent Hours
$0.00	910	100.0%	1,249	100.0%
$1.00	873	95.9%	1,193	95.5%
$5.00	716	78.7%	989	79.2%
$10.00	572	62.9%	715	57.2%
$15.00	454	49.9%	544	43.6%
$20.00	388	42.6%	423	33.9%
$25.00	339	37.3%	327	26.2%
$50.00	188	20.7%	166	13.3%
$75.00	112	12.3%	98	7.8%
$100.00	69	7.6%	69	5.5%
$200.00	21	2.3%	20	1.6%
$300.00	9	1.0%	6	0.5%
$400.00	5	0.5%	5	0.4%
$500.00	5	0.5%	5	0.4%

Summary of Interface Prices between PJM and Organized Markets

Some measures of the real-time and day-ahead PJM interface pricing with MISO and with the NYISO are summarized and compared in Table 9-30, including average prices and measures of variability.

Table 9-30 PJM, NYISO and MISO border price averages: January through March, 2026[26]

		Real-Time		Day-Ahead	
	Description	NYISO	MISO	NYISO	MISO
Average Interval Price	PJM Price at ISO Border	$78.31	$49.61	$86.78	$58.95
	ISO Price at PJM Border	$79.28	$56.50	$97.51	$59.06
	Difference at Border (PJM-ISO)	($0.97)	($6.89)	($10.73)	($0.10)
	Average Absolute Value of Interval Difference at Border	$40.66	$30.70	$21.76	$13.39
	Sign Changes per Day	14.2	15.1	0.8	1.0
Standard Deviation	PJM Price at ISO Border	$117.11	$86.05	$110.14	$76.34
	ISO Price at PJM Border	$111.21	$150.19	$131.37	$77.18
	Difference at Border (PJM-ISO)	$115.59	$150.73	$54.35	$34.95

Neptune Underwater Transmission Line to Long Island, New York

The Neptune Line is a 65 mile direct current (DC) merchant 230 kV transmission line, with a capacity of 660 MW, providing a direct connection between PJM (Sayreville, New Jersey), and NYISO (Nassau County on Long Island). Schedule 14 of the PJM Open Access Transmission Tariff provides that power flows will only be from PJM to New York. The flows were consistent with price differentials in 82.4 percent of the hours in the first three months of 2026. Table 9-31 shows the number of hours and average hourly price differences between the PJM/NEPT Interface and the NYIS/Neptune bus based on LMP differences and flow direction.

Table 9-31 PJM and NYISO flow based hours and price differences (Neptune): January through March, 2026

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Neptune Bus LBMP > PJM/NEPT LMP	Total Hours	1,779	$39.87
	Consistent Flow (PJM to NYIS)	1,779	$39.87
	Inconsistent Flow (NYIS to PJM)	0	$0.00
	No Flow	0	$0.00
PJM/NEPT LMP > NYIS/Neptune Bus LBMP	Total Hours	380	$85.96
	Consistent Flow (NYIS to PJM)	0	$0.00
	Inconsistent Flow (PJM to NYIS)	380	$85.96
	No Flow	0	$0.00

26 Effective April 1, 2018, PJM implemented five minute LMP settlements in the real-time energy market. The sign changes per day represented in this table reflect the number of intervals where the sign changed per day. For the real-time energy market, there are 288 five minute intervals per day. For the day-ahead market there are 24 hourly intervals per day.

To move power from PJM to NYISO using the Neptune Line, two PJM transmission service reservations are required. A transmission service reservation is required from the PJM Transmission System to the Neptune HVDC Line ("Out Service") and another transmission service reservation is required on the Neptune HVDC Line ("Neptune Service").[27] The PJM Out Service is covered by normal PJM OASIS business operations.[28] The Neptune Service falls under the provisions for controllable merchant facilities, Schedule 14 of the PJM Tariff. The Neptune Service is also acquired on the PJM OASIS.

Neptune Service is owned by a primary rights holder, and any nonfirm service that is not used (as defined by a schedule on a NERC Tag) may be released either voluntarily by the primary rights holder or by default by PJM. The primary rights holder may elect to voluntarily release monthly, weekly, daily or hourly firm or nonfirm service. Voluntarily releasing the service allows for the primary rights holder to specify a rate to be charged for the released service. If the primary rights holder does not elect to voluntarily release nonfirm service, and does not use the service, the available transmission will be released by default at 12:00, one business day before the start of service. On March 31, 2026, the rate for the nonfirm service released by default was $10.00 per MWh. The primary rights holder remains obligated to pay for the released service unless a second transmission customer acquires the released service.

Table 9-32 shows the percent of scheduled interchange across the Neptune Line by the primary rights holder since commercial operations began in July 2007. Table 9-32 shows that in the first three months of 2026, the primary rights holder was responsible for 100 percent of the scheduled interchange across the Neptune Line in all months. Figure 9-7 shows the hourly average flow across the Neptune Line for the first three months of 2026.

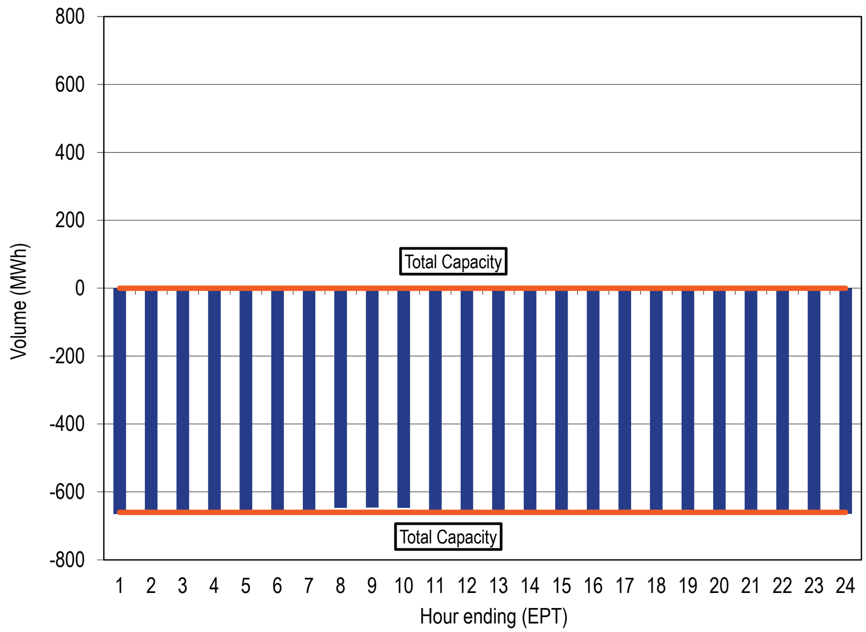
27 See OASIS "PJM Business Practices for Neptune Transmission Service," (August 21, 2015) <https://www.pjm.com/-/media/DotCom/etools/oasis/merch-trans-facilities/neptune-oasis-business-practices-doc-clean.pdf>.

28 See OASIS "Regional Transmission and Energy Scheduling Practices," Rev. 13 (January 22, 2026) <https://www.pjm.com/-/media/DotCom/etools/oasis/regional-practices-clean-pdf.pdf>.

Table 9-32 Percent of scheduled interchange across the Neptune Line by primary rights holder: July 2007 through March 2026

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
January	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
February	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
March	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
April	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	99.99%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
May	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
June	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	99.41%	
July	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
August	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
September	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
October	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
November	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
December	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	

Figure 9-7 Neptune hourly average flow: January through March, 2026



Linden Variable Frequency Transformer (VFT) facility

The Linden VFT facility is a controllable AC merchant transmission facility, with a capacity of 315 MW, providing a direct connection between PJM (Linden, New Jersey) and NYISO (Staten Island, New York). The flows were consistent with price differentials in 81.4 percent of the hours in the first three months of 2026. Table 9-33 shows the number of hours and average hourly price differences between the PJM/LIND Interface and the NYIS/Linden Bus based on LMP differences and flow direction.

Table 9-33 PJM and NYISO flow based hours and price differences (Linden): January through March, 2026

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Linden Bus LBMP > PJM/LIND LMP	Total Hours	1,758	$40.47
	Consistent Flow (PJM to NYIS)	1,758	$40.47
	Inconsistent Flow (NYIS to PJM)	0	$0.00
	No Flow	0	$0.00
PJM/LIND LMP > NYIS/Linden Bus LBMP	Total Hours	401	$80.05
	Consistent Flow (NYIS to PJM)	0	$0.00
	Inconsistent Flow (PJM to NYIS)	401	$80.05
	No Flow	0	$0.00

To move power from PJM to NYISO on the Linden VFT Line, two PJM transmission service reservations are required. A transmission service reservation is required from the PJM Transmission System to the Linden VFT ("Out Service") and another transmission service reservation is required on the Linden VFT ("Linden VFT Service").[29] The PJM Out Service is covered by normal PJM OASIS business operations.[30] The Linden VFT Service falls under the provisions for controllable merchant facilities, Schedule 16 and Schedule 16-A of the PJM Tariff. The Linden VFT Service is also acquired on the PJM OASIS.

29 See OASIS "PJM Business Practices for Linden VFT Transmission Service," (June 1, 2011) <https://www.pjm.com/-/media/DotCom/etools/oasis/merch-trans-facilities/linden-vft-oasis-business-practices-clean.pdf>.

30 See OASIS "Regional Transmission and Energy Scheduling Practices," Rev. 13 (January 22, 2026) <https://www.pjm.com/-/media/DotCom/etools/oasis/regional-practices-clean-pdf.pdf>.

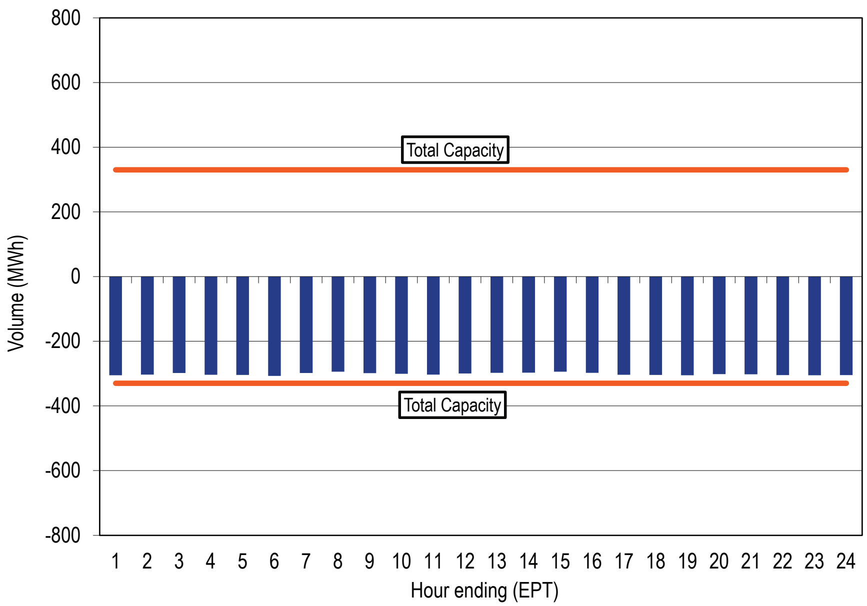
Linden VFT Service is owned by a primary rights holder, and any nonfirm service that is not used (as defined by a schedule on a NERC Tag) may be released either voluntarily by the primary rights holder or by default by PJM. The primary rights holder may elect to voluntarily release monthly, weekly, daily or hourly firm or nonfirm service. Voluntarily releasing the service allows for the primary rights holder to specify a rate to be charged for the released service. If the primary rights holder elects to not voluntarily release nonfirm service, and does not use the service, the available transmission will be released by default at 1200 (EPT), one business day before the start of service. On March 31, 2026, the rate for the nonfirm service released by default was $6.00 per MWh. The primary rights holder remains obligated to pay for the released service unless a second transmission customer acquires the released service.

Table 9-34 shows the percent of scheduled interchange across the Linden VFT Line by the primary rights holder since commercial operations began in November, 2009. Table 9-34 shows that in the first three months of 2026, the primary rights holder was responsible for 100 percent of the scheduled interchange across the Linden VFT Line in all months. Figure 9-8 shows the hourly average flow across the Linden VFT Line for the first three months of 2026.

Table 9-34 Percent of scheduled interchange across the Linden VFT Line by primary rights holder: November 2009 through March 2026

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
January	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	70.53%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
February	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	94.95%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
March	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	96.46%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
April	NA	99.97%	100.00%	100.00%	100.00%	99.98%	100.00%	49.32%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
May	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
June	NA	100.00%	100.00%	100.00%	100.00%	27.27%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
July	NA	100.00%	100.00%	100.00%	100.00%	29.56%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
August	NA	100.00%	100.00%	100.00%	100.00%	82.46%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
September	NA	100.00%	100.00%	100.00%	100.00%	81.68%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
October	NA	100.00%	100.00%	100.00%	100.00%	100.00%	35.05%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
November	100.00%	100.00%	100.00%	100.00%	99.86%	100.00%	61.45%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
December	100.00%	100.00%	100.00%	98.22%	100.00%	100.00%	84.57%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	

Figure 9-8 Linden hourly average flow: January through March, 2026[31]



31 The Linden VFT Line is a bidirectional facility. The "Total Capacity" lines represent the maximum amount of interchange possible in either direction. These lines were included to maintain a consistent scale, for comparison purposes, with the Neptune DC Tie Line.

the hours in the first three months of 2026. Table 9-35 shows the number of hours and average hourly price differences between the PJM/HUDS Interface and the NYIS/Hudson bus based on LMP differences and flow direction.

Table 9-35 PJM and NYISO flow based hours and price differences (Hudson): January through March, 2026

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Hudson Bus LBMP > PJM/HUDS LMP	Total Hours	1,825	$43.78
	Consistent Flow (PJM to NYIS)	1,600	$45.82
	Inconsistent Flow (NYIS to PJM)	0	$0.00
	No Flow	225	$29.29
PJM/HUDS LMP > NYIS/ Hudson Bus LBMP	Total Hours	334	$56.69
	Consistent Flow (NYIS to PJM)	0	$0.00
	Inconsistent Flow (PJM to NYIS)	313	$59.79
	No Flow	21	$10.47

To move power from PJM to NYISO on the Hudson Line, two PJM transmission service reservations are required. A transmission service reservation is required from the PJM Transmission System to the Hudson Line (“Out Service”) and another transmission service reservation is required on the Hudson Line (“Hudson Service”).[32] The PJM Out Service is covered by normal PJM OASIS business operations.[33] The Hudson Service falls under the provisions for controllable merchant facilities, Schedule 17 of the PJM Tariff. The Hudson Service is also acquired on the PJM OASIS.

Hudson Service is owned by a primary rights holder, and any nonfirm service that is not used (as defined by scheduled on a NERC Tag) may be released either voluntarily by the primary rights holder or by default by PJM. The primary rights holder may elect to voluntarily release monthly, weekly, daily or hourly firm or nonfirm service. Voluntarily releasing the service allows for the primary rights holder to specify a rate to be charged for the released service. If the primary rights holder elects to not voluntarily release nonfirm service, and does not use the service, the available transmission will be released by default at 1200 (EPT), one business day before the start of service. On March 31, 2026, the rate for the nonfirm service released by default was $10.00 per MWh. The primary rights holder remains obligated to pay for the released service unless a second transmission customer acquires the released service.

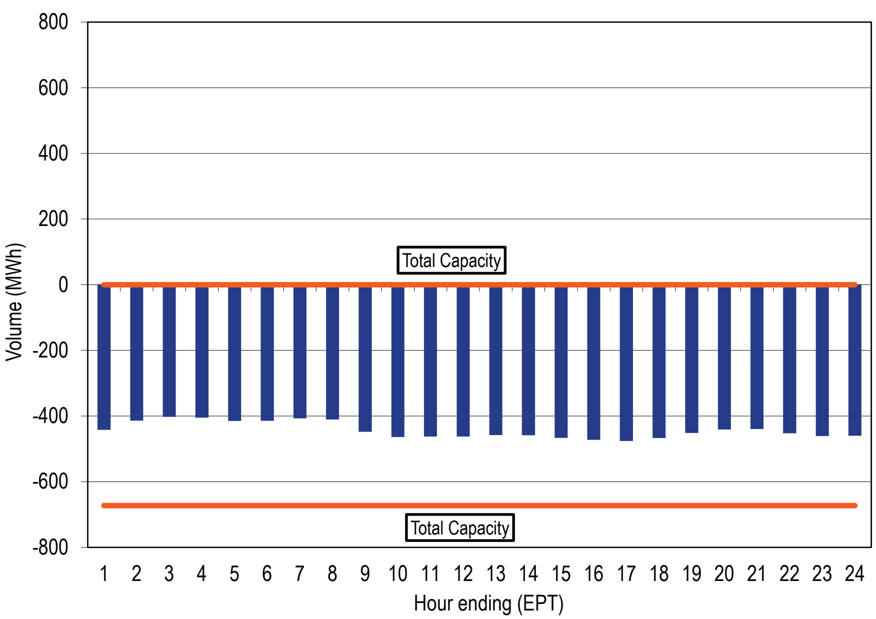
Table 9-36 shows the percent of scheduled interchange across the Hudson Line by the primary rights holder since commercial operations began in May, 2013. Table 9-36 shows that in the first three months of 2026, the primary rights holder was responsible for 100 percent of the scheduled interchange across the Hudson Line in all months. Figure 9-9 shows the hourly average flow across the Hudson Line for the first three months of 2026.

32 See OASIS "PJM Business Practices for Hudson Transmission Service,"<https://www.pjm.com/-/media/DotCom/etools/oasis/merch-trans-facilities/hudson-oasis-business-practices-clean.pd
33 See OASIS "Regional Transmission and Energy Scheduling Practices," Rev. 13 (January 22, 2026) <https://www.pjm.com/-/media/DotCom/etools/oasis/regional-practices-clean-pdf.pdf>.

Table 9-36 Percent of scheduled interchange across the Hudson Line by primary rights holder: May 2013 through March 2026[34]

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
January	NA	51.22%	16.27%	100.00%	NA	24.44%	52.21%	29.70%	37.64%	64.30%	81.40%	100.00%	100.00%	100.00%
February	NA	49.00%	14.67%	NA	NA	23.25%	77.12%	23.61%	47.37%	64.34%	82.72%	100.00%	100.00%	100.00%
March	NA	40.40%	71.88%	NA	NA	9.55%	72.42%	87.24%	53.27%	82.65%	83.41%	100.00%	100.00%	100.00%
April	NA	100.00%	100.00%	NA	NA	15.13%	100.00%	10.02%	70.90%	84.91%	100.00%	100.00%	100.00%	
May	100.00%	26.87%	100.00%	100.00%	NA	92.18%	100.00%	20.53%	65.15%	84.15%	100.00%	100.00%	100.00%	
June	100.00%	5.89%	59.72%	100.00%	NA	44.89%	44.98%	38.26%	73.81%	100.00%	100.00%	100.00%	100.00%	
July	100.00%	18.51%	84.34%	NA	NA	16.26%	36.43%	27.56%	76.56%	100.00%	89.66%	100.00%	100.00%	
August	100.00%	75.17%	65.48%	NA	NA	19.24%	43.10%	35.64%	59.09%	100.00%	100.00%	80.35%	100.00%	
September	100.00%	75.31%	78.73%	NA	NA	22.90%	43.42%	30.75%	53.66%	100.00%	100.00%	100.00%	100.00%	
October	100.00%	99.71%	18.65%	100.00%	NA	22.67%	33.60%	52.58%	56.26%	100.00%	100.00%	100.00%	100.00%	
November	85.57%	99.60%	24.67%	100.00%	80.12%	50.44%	44.36%	38.60%	65.24%	68.68%	70.50%	100.00%	100.00%	
December	28.32%	1.68%	100.00%	NA	21.93%	29.38%	41.78%	38.82%	61.11%	70.02%	83.43%	100.00%	100.00%	

Figure 9-9 Hudson hourly average flow: January through March, 2026



34 The designation of "NA" means there was no flow on the Hudson Line during those months.

Interchange Activity During High Load Hours

The PJM metered system peak load during the first three months of 2026 was 135,722 MW in the HE 0700 (EPT) on January 29, 2026. PJM was a net scheduled exporter of energy in all 24 hours on January 29, 2026, with average hourly scheduled exports of 3,768 MW. During HE 0700 on January 29, 2026, PJM had net scheduled exports of 2,878 MW and net metered actual exports of 2,991 MW. Net transaction exports during 0700 were consistent with price differences between the PJM/LIND Interface and the NYIS/Linden Bus and the PJM/HUDS Interface and the NYIS/Hudson Bus and between PJM and the NYISO. Net transaction exports were inconsistent with price differences between the PJM/NEPT Interface and the NYIS/Neptune bus and between PJM and MISO. During January 2025, PJM was a net scheduled exporter of energy in 739 of the 744 hours (99.3 percent of the hours). During January 2025, the average hourly scheduled interchange was -3,741 MW (representing 3.5 percent of the average hourly load of 106,858 MW in June 2025).

Operating Agreements with Bordering Areas

To improve reliability and reduce potential seams issues, PJM and its neighbors have developed operating agreements, including: operating agreements with MISO and the NYISO; a reliability agreement with TVA, LG&E and KU; an operating agreement with Duke Energy Progress, Inc.; a reliability coordination agreement with VACAR South; a balancing authority operations agreement with the Wisconsin Electric Power Company (WEC); and a Northeastern planning coordination protocol with NYISO and ISO New England.

Table 9-37 shows a summary of the elements included in each of the operating agreements PJM has with its bordering areas.

Table 9-37 Summary of elements included in operating agreements with bordering areas

Agreement:	PJM-MISO	PJM-NYISO	PJM-TVA-LGE-KU	PJM-DEP	PJM-VACAR	PJM-WEP	Northeastern Protocol
Data Exhange							
Real-Time Data	YES	YES	YES	YES	YES	YES	NO
Projected Data	YES	YES	YES	YES	NO	NO	NO
SCADA Data	YES	YES	YES	YES	NO	NO	NO
EMS Models	YES	YES	YES	YES	NO	NO	YES
Operations Planning Data	YES	YES	YES	YES	NO	NO	YES
Available Flowgate Capability Data	YES	YES	YES	YES	NO	NO	YES
Near-Term System Coordination							
Operating Limit Violation Assistance	YES	YES	YES	YES	YES	NO	NO
Over/Under Voltage Assistance	YES	YES	YES	YES	YES	NO	NO
Emergency Energy Assistance	YES	YES	NO	YES	YES	NO	NO
Outage Coordination	YES	YES	YES	YES	YES	NO	NO
Long-Term System Coordination	YES	YES	YES	YES	NO	NO	YES
Congestion Management Process							
ATC Coordination	YES	YES	YES	YES	NO	NO	NO
Market Flow Calculations	YES	YES	YES	NO	NO	NO	NO
Firm Flow Entitlements	YES	YES	YES	NO	NO	NO	NO
Market to Market Redispatch	YES - Redispatch	YES - Redispatch	NO	NO	NO	NO	NO
Joint Checkout Procedures	YES	YES	YES	YES	NO	YES	NO

PJM-MISO = MISO/PJM Joint Operating Agreement
PJM-NYISO = New York ISO/PJM Joint Operating Agreement
PJM-TVA-LGE-KU = Joint Reliablity Coordination Agreement Between PJM - Tennessee Valley Authority (TVA), Louisville Gas and Electric Company (LGE) and Kentucky Utilities Company (KU)
PJM-DEP = Duke Energy Progress (DEP) - PJM Joint Operating Agreement
PJM-VACAR = PJM-VACAR South Reliability Coordination Agreement
PJM-WEP = Balancing Authority Operations Coordination Agreement Between Wisconsin Electric Power Company and PJM Interconnection, LLC
Northeastern Protocol = Northeastern ISO-Regional Transmission Organization Planning Coordination Protocol

PJM and MISO Joint Operating Agreement[35]

The Joint Operating Agreement between MISO and PJM Interconnection, L.L.C. was executed on December 31, 2003. The PJM/MISO JOA includes provisions for congestion management that, for designated flowgates within MISO and PJM, allows for redispatch of units within the PJM and MISO regions to jointly manage congestion on these flowgates and to assign the costs of congestion management. This process was designed to address the impacts of market flows which are the loop flows on MISO's system created by PJM generators serving PJM load and vice versa. In 2012, MISO and PJM initiated a joint stakeholder process to address issues associated with the operation of the markets at the seam.[36]

Under the market to market rules, the organizations coordinate pricing at their borders. PJM and MISO each calculate an interface LMP using network models including distribution factor impacts. PJM uses 10 buses along the PJM/MISO border to calculate the PJM/MISO interface pricing point LMP. Prior to June 1, 2017, MISO used all of the PJM generator buses in its model of the PJM system in its calculation of the MISO/PJM interface pricing point.[37] On June 1, 2017, MISO modified their MISO/PJM interface definition to match PJM's PJM/MISO interface definition.

Coordinated flowgates are identified to determine which flowgates the market flows from PJM or MISO affect significantly. This set of flowgates may then be used in the congestion management process. PJM and MISO will conduct sensitivity studies to determine which flowgates are significantly affected by the market flows of the operating entity's control zones (historic control areas that existed in the IDC). There are five studies to determine which flowgates the operating entity will monitor and help control. These studies include generation to load distribution factor studies, transfer distribution factor analysis and an external asynchronous resource study. PJM or MISO may also specify additional flowgates that have not passed any of the five studies to be coordinated flowgates where the operating entity expects to use the TLR process to manage congestion. A reciprocal coordinated flowgate (RCF) is a CF that is monitored and controlled by PJM or MISO, on which both have significant impacts. Only RCFs are subject to the market to market congestion management process.[38]

As of January 1, 2026, PJM had 131 flowgates eligible for M2M (Market to Market) coordination. In the first three months of 2026, PJM added three flowgates and deleted four flowgates, resulting in 130 flowgates eligible for M2M coordination as of March 31, 2026. As of January 1, 2026, MISO had 179 flowgates eligible for M2M coordination. In the first three months of 2026, MISO added 17 flowgates and deleted 11 flowgates, resulting in 185 flowgates eligible for M2M coordination as of March 31, 2026.

The firm flow entitlement (FFE) represents the amount of historic 2004 market flows that each RTO had created on each RCF used in the market to market settlement process. The FFE establishes the amount of market flow that each RTO is permitted to create on the RCF before incurring redispatch costs during the market to market process. If the nonmonitoring RTO's real-time market flow is greater than their FFE plus the approved MW adjustment from day-ahead coordination, then the nonmonitoring RTO will pay the monitoring RTO the difference between their market flow and their FFE times the monitoring

RTO's shadow price of the RCF. The shadow price is the incremental cost of dispatching marginal generation resources to relieve congestion on the RCF. If the nonmonitoring RTO's real-time market flow is less than their FFE plus the approved MW adjustment from day-ahead coordination, then the monitoring RTO will pay the nonmonitoring RTO for congestion relief provided by the nonmonitoring RTO. This payment is the difference between the nonmonitoring RTO's market flow and their FFE times the monitoring RTO's shadow price of the RCF.

April 1, 2004, known as the freeze date, is used to determine the firm rights on flowgates based on historic firm market flows that occurred prior to the

35 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) <https://www.pjm.com/directory/merged-tariffs/miso-joa.pdf>.

36 See "PJM/MISO Joint and Common Market Initiative," <https://www.pjm.com/committees-and-groups/stakeholder-meetings/pjm-miso-joint-common>.

37 See the *2012 Annual State of the Market Report for PJM*, Volume 2, Section 8, "Interchange Transactions," for a more detailed discussion.

38 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) <https://www.pjm.com/directory/merged-tariffs/miso-joa.pdf>.

implementation of M2M coordination. In the 21 years since 2004, significant topology and market changes have occurred, making the 2004 market flows irrelevant in 2026. The RTOs and stakeholders recognize that a modification to the definition of firm rights on flowgates is necessary. PJM and MISO stakeholders have spent years on the freeze date issues. No resolution to these issues appears imminent. The status quo results in significant payments by PJM customers to MISO customers. The final resolution should account for the investments made by each RTO in the transmission system. The final resolution should reflect current interchange patterns. In 2004, PJM was primarily an importer of energy from MISO. In the first three months of 2026, as it has been since about 2010, PJM is primarily an exporter of energy to MISO.

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. PJM and MISO have demonstrated a longstanding failure to resolve the definition of firm rights on flowgates and related issues. 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.

The original logic of FFEs was not clear, the calculation of FFEs was not clear, and the measurement of market flows was and is imprecise at best. It does not make sense to use outdated and meaningless FFEs from 2004. If current FFEs are used based on actual current power flows, the role of FFEs is not clear. Fully dynamic FFEs are equivalent to eliminating FFEs while continuing to price power flows at the correct shadow price.

The solution to the FFE and M2M issue is to eliminate FFEs. Elimination of FFEs, while maintaining the exchange of shadow price information and cooperative dispatch, would keep the benefits of efficient constraint resolution between PJM and MISO.

In the first three months of 2026, market to market operations resulted in MISO and PJM redispatching units to control congestion on M2M flowgates and the exchange of payments for this redispatch. Table 9-38 shows credits for coordinated congestion management between PJM and MISO. In the first three months of 2026, MISO payments to PJM were $10.7 million, and PJM payments to MISO were $80.6 million, for a net payment from PJM to MISO of $69.8 million. The large settlements in 2022 were due to the large amount of congestion and high LMPs observed in December during Winter Storm Elliott.

Table 9-38 PJM/MISO credits for coordinated congestion management: April 2005 through March 2026[39]

Year	Payments from PJM to MISO	Payments from MISO to PJM	Net Payment from PJM to MISO
2005	$25,068,903	$3,411,188	$21,657,715
2006	$18,664,630	$21,381,460	($2,716,830)
2007	$29,917,241	$17,774,637	$12,142,604
2008	$60,615,478	$15,417,040	$45,198,438
2009	$48,101,017	$10,632,885	$37,468,132
2010	$56,330,068	$20,558,982	$35,771,087
2011	$87,113,498	$9,445,949	$77,667,550
2012	$56,227,681	$7,602,112	$48,625,569
2013	$32,589,519	$14,733,770	$17,855,748
2014	$62,572,610	$19,263,896	$43,308,713
2015	$49,379,823	$11,266,866	$38,112,957
2016	$50,628,816	$9,826,347	$40,802,469
2017	$69,812,858	$16,698,276	$53,114,581
2018	$110,501,078	$10,400,122	$100,100,956
2019	$44,391,547	$7,886,392	$36,505,155
2020	$53,038,595	$7,985,027	$45,053,568
2021	$45,704,128	$18,792,183	$26,911,945
2022	$191,716,652	$8,560,992	$183,155,660
2023	$63,976,499	$5,467,435	$58,509,064
2024	$58,627,460	$17,671,566	$40,955,894
2025	$99,190,899	$8,099,528	$91,091,371
2026 (Jan)	$45,006,873	$9,008,623	$35,998,251
2026 (Feb)	$20,309,609	$115,595	$20,194,014
2026 (Mar)	$15,240,081	$1,623,814	$13,616,267
2026	$80,556,563	$10,748,031	$69,808,532

39 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

PJM and New York Independent System Operator Joint Operating Agreement (JOA)[40]

The Joint Operating Agreement between NYISO and PJM Interconnection, L.L.C. became effective on January 15, 2013. Under the market to market rules, the organizations coordinate pricing at their borders. Unlike the PJM/MISO JOA where firm flow entitlements are based on a freeze date, the PJM/NYISO JOA requires that each party calculates an M2M entitlement on each M2M flowgate and compare results at least once a year. This annual coordination of entitlements ensures that the impact of upgrades on both systems are incorporated into the M2M calculation. PJM and NYISO may mutually agree to not recalculate entitlements in a given year.

On June 28, 2019, NYISO and PJM submitted revisions to the NYISO-PJM Joint Operating Agreement (JOA). The revisions addressed RTO concerns identified in their joint request for limited waiver of the JOA to authorize redispatch of generation in PJM. The intent of the redispatch is to mitigate post-contingency overloads of transmission equipment on the New York side of the East Towanda-Hillside 230 kV Transmission Line. The agreement allows the RTOs to control for this contingency without the exchange of payments for redispatch.[41]

In the first three months of 2026, market to market operations did not result in NYISO and PJM redispatching units to control congestion on M2M flowgates. Therefore, there was no exchange of payments for redispatch in the first three months of 2026. Table 9-39 shows credits for coordinated congestion management between PJM and NYISO.

Table 9-39 PJM/NYISO credits for coordinated congestion management (flowgates): January 2013 through March 2026[42]

Year	Payments from PJM to NYISO	Payments from NYISO to PJM	Net Payment from PJM to NYISO
2013	$119,121	$0	$119,121
2014	$58,631	$1,005	$57,626
2015	$242,488	$5,063	$237,425
2016	$632,768	$50,550	$582,219
2017	$422,304	$895	$421,409
2018	$0	$0	$0
2019	$0	$0	$0
2020	$0	$0	$0
2021	$0	$0	$0
2022	$0	$0	$0
2023	$0	$0	$0
2024	$0	$0	$0
2025	$0	$0	$0
2026 (Jan)	$0	$0	$0
2026 (Feb)	$0	$0	$0
2026 (Mar)	$0	$0	$0
2026	$0	$0	$0

The M2M coordination process focuses on real-time market coordination to manage transmission limitations that occur on M2M flowgates in a cost effective manner. Coordination between NYISO and PJM includes not only joint redispatch, but also incorporates coordinated operation of the PARs that are located at the PJM/NYIS border. This real-time coordination results in an efficient economic dispatch solution across both markets to manage the real-time transmission constraints that affect both markets, focusing on the actual flows in real time to manage constraints.[43] For each M2M flowgate, a PAR settlement will occur for each interval during coordinated operations. The PAR settlements are determined based on whether the measured real-time flow on each of the PARs is greater than or less than the calculated target value. If the actual flow is greater than the target flow, NYISO will make a payment to PJM. This payment is calculated as the product of the M2M flowgate shadow price, the PAR shift factor and the difference between the actual and target PAR flow. If the actual flow is less than the target flow, PJM will make a payment

40 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C.," (September 16, 2019) <https://www.pjm.com/~/media/DotCom/documents/agreements/nyiso-joa.ashx>.

41 See NYISO Filing, FERC Docket No. ER19-2282-000 (June 28, 2019).

42 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements

43 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C.," (September 16, 2019) <https://www.pjm.com/~/media/DotCom/documents/agreements/nyiso-joa.ashx>

to NYISO. This payment is calculated as the product of the M2M flowgate shadow price, the PAR shift factor and the difference between the target and actual PAR flow. Effective May 1, 2017, coincident with the termination of the ConEd wheel, PJM and NYISO began M2M coordination at all of the PARs along the PJM/NYISO seam. Prior to May 1, 2017, only the Ramapo PARs were included in the M2M process. In the first three months of 2026, market to market operations resulted in NYISO and PJM adjusting PARs to control congestion and the exchange of payments for this coordination. In the first three months of 2026, PJM payments to NYISO were $460,493, and NYISO payments to PJM were $692,735, for a net payment from NYISO to PJM of $232,242. Table 9-40 shows the PAR credits for coordinated congestion management between PJM and NYISO.

Table 9-40 PJM/NYISO credits for coordinated congestion management (PARs): January 2013 through March 2026[44]

Year	Payments from PJM to NYISO	Payments from NYISO to PJM	Net Payment from PJM to NYISO
2013	$7,403,255	$0	$7,403,255
2014	$5,723,571	$0	$5,723,571
2015	$4,691,302	$0	$4,691,302
2016	$617,733	$0	$617,733
2017	$2,328,763	$2,115,126	$213,637
2018	$3,327,747	$2,407,667	$920,081
2019	$3,341,615	$2,923,715	$417,900
2020	$3,004,543	$2,048,317	$956,226
2021	$8,911,160	$6,751,890	$2,159,270
2022	$21,126,437	$13,609,266	$7,517,171
2023	$1,755,207	$2,208,388	($453,181)
2024	$376,435	$1,227,033	($850,597)
2025	$2,515,938	$3,667,855	($1,151,917)
2026 (Jan)	$158,870	$121,212	$37,658
2026 (Feb)	$266,656	$319,741	($53,085)
2026 (Mar)	$34,967	$251,782	($216,815)
2026	$460,493	$692,735	($232,242)

44 The totals in this figure are from the settlements at the time of this report and may change based on later adjustments or resettlements.

PJM and TVA/LG&E and KU Joint Reliability Coordination Agreement (JRCA)[45]

The joint reliability coordination agreement (JRCA) executed on April 22, 2005, provides for the exchange of information and the implementation of reliability and efficiency protocols between TVA and PJM. The agreement also provides for the management of congestion and arrangements for both near-term and long-term system coordination. Under the JRCA, PJM and TVA honor constraints on the other's flowgates in their Available Transmission Capability (ATC) calculations. Market flows are calculated on reciprocal flowgates. When a constraint occurs on a reciprocal flowgate within TVA, PJM has the option to redispatch generation to reduce market flow, and therefore alleviate the constraint. Unlike the M2M procedure between MISO and PJM, this redispatch does not result in M2M payments. However, electing to redispatch generation within PJM can avoid potential market disruption by curtailing transactions under the Transmission Line Loading Relief (TLR) procedure to achieve the same relief. In 2022, PJM and TVA began discussions to add Louisville Gas and Electric Company (LG&E) and Kentucky Utilities (KU) as parties to the JRCA. The revisions to add LG&E and KU to the agreement were filed with the Commission on June 6, 2023.[46] On August 5, 2023, the Commission approved the filing.[47] The agreement remained in effect in the first three months of 2026.

PJM and Duke Energy Progress, Inc. Joint Operating Agreement[48]

On September 9, 2005, FERC approved a JOA between PJM and Progress Energy Carolinas, Inc. (PEC), with an effective date of July 30, 2005. As part of this agreement, both parties agreed to develop a formal congestion management protocol (CMP). On February 2, 2010, PJM and PEC filed a revision to include a CMP under Article 14 of the JOA.[49] On January 20, 2011, the Commission

45 See "Joint Reliability Coordination Agreement Among and Between PJM Interconnection, L.L.C., and Tennessee Valley Authority," (October 15, 2014) <https://www.pjm.com/library/governing-documents>.
46 See *PJM Interconnection, L.L.C*, Docket No. ER23-2078-000 (June 6, 2023)
47 See *PJM Interconnection, L.L.C*, Docket No. ER23-2078-000 (August 5, 2023).
48 See "Amended and Restated Joint Operating Agreement Among and Between PJM Interconnection, L.L.C., and Duke Energy Progress Inc.," (July 22, 2019) <https://www.pjm.com/directory/merged-tariffs/progress-joa.pdf>.
49 See *PJM Interconnection, L.L.C and Progress Energy Carolinas, Inc.* Docket No. ER10-713-000 (February 2, 2010).

conditionally accepted the compliance filing. On July 2, 2012, Duke Energy and Progress Energy Inc. completed a merger. At that time, Progress Energy Carolinas Inc., now a subsidiary of Duke Energy, changed its name to Duke Energy Progress (DEP).

On May 20, 2019, PJM and DEP submitted revisions to the JOA to delete Article 14.[50] PJM and DEP requested an effective date of July 22, 2019, for the filed revisions. On July 2, 2019, the Commission issued a letter order accepting the revisions to the JOA to delete the congestion management agreement effective July 22, 2019.[51]

PJM and VACAR South Reliability Coordination Agreement[52]

On May 23, 2007, PJM and VACAR South (comprised of Duke Energy Carolinas, LLC (DUK), DEP, South Carolina Public Service Authority (SCPSA), Southeast Power Administration (SEPA), South Carolina Energy and Gas Company (SCE&G) and Yadkin Inc. (part of Alcoa)) entered into a reliability coordination agreement which provides for system and outage coordination, emergency procedures and the exchange of data. The parties meet on a yearly basis. The agreement remained in effect in the first three months of 2026.

Balancing Authority Operations Coordination Agreement between Wisconsin Electric Power Company (WEC) and PJM Interconnection, LLC[53]

The Balancing Authority Operations Coordination Agreement executed on July 20, 2013, provides for the exchange of information between WEC and PJM. The purpose of the data exchange is to allow for the coordination of balancing authority actions to ensure the reliable operation of the systems. The agreement remained in effect in the first three months of 2026.

50 See *PJM Interconnection, L.L.C*, Docket No. ER19-1905-000 (May 20, 2019).
51 See FERC Docket No. ER19-1905-000.
52 See "PJM-VACAR South RC Agreement," (November 7, 2014) <https://www.pjm.com/-/media/DotCom/documents/agreements/executed-pjm-vacar-rc-agreement.pdf>.
53 See "Balancing Authority Operations Coordination Agreement between Wisconsin Electric Power Company and PJM Interconnection, L.L.C.," (July 20, 2013) <https://www.pjm.com/directory/merged-tariffs/rs43.pdf>.

Northeastern ISO-Regional Transmission Organization Planning Coordination Protocol[54]

The Northeastern ISO-RTO Planning Coordination Protocol executed on December 8, 2004, provides for the exchange of information among PJM, NYISO and ISO New England. The purpose of the data exchange is to allow for the long-term planning coordination among and between the ISOs and RTOs in the Northeast. The agreement remained in effect in the first three months of 2026.

Interchange Transaction Issues

PJM Transmission Loading Relief Procedures (TLRs)

TLRs are called to control flows on electrical facilities when economic redispatch cannot solve overloads on those facilities. TLRs are called to control flows related to external balancing authorities, loop flows for example, as redispatch within an LMP market can generally resolve overloads on internal transmission facilities.

The number of PJM issued TLRs of level 3a or higher was two in the first three months of 2025, and two in the first three months of 2026. The number of different flowgates for which PJM declared a TLR 3a was two in the first three months of 2025, and two in the first three months of 2026. The total MWh of transaction curtailments decreased by 39.4 percent from 5,646 MWh in the first three months of 2025 to 3,419 MWh in the first three months of 2026.[55]

The number of MISO issued TLRs of level 3a or higher increased from three in the first three months of 2025 to 18 in the first three months of 2026. The number of different flowgates for which MISO declared a TLR 3a was three in the first three months of 2025, and 11 in the first three months of 2026. The total MWh of transaction curtailments increased by 623.4 percent from 5,386 MWh in the first three months of 2025 to 38,964 MWh in the first three months of 2026.

54 See "Northeastern ISO/RTO Planning Coordination Protocol," (December 8, 2004) <https://www.pjm.com/-/media/DotCom/documents/agreements/NE_Protocol.ashx>.
55 TLR Level 3a is the first level of TLR that results in the curtailment of transactions. See the *2019 Annual State of the Market Report for PJM*, Appendix E, "Interchange Transactions," for a more complete discussion of TLR levels.

The number of NYISO issued TLRs of level 3a or higher was zero in the first three months of 2025, and zero in the first three months of 2026. The number of different flowgates for which NYISO declared a TLR 3a or higher was zero in the first three months of 2025, and zero in the first three months of 2026. The total MWh of transaction curtailments was zero MWh in the first three months of 2025, and zero MWh in the first three months of 2026.

Table 9-41 PJM, MISO, and NYISO TLR procedures: January through March, 2026[56]

Month	Number of TLRs Level 3 and Higher PJM	MISO	NYISO	Number of Unique Flowgates That Experienced TLRs PJM	MISO	NYISO	Curtailment Volume (MWh) PJM	MISO	NYISO
Jan-26	1	13	0	1	9	0	2,887	31,425	0
Feb-26	1	4	0	1	2	0	532	7,539	0
Mar-26	0	1	0	0	1	0	0	0	0
Total	2	18	0	2	11	0	3,419	38,964	0

Table 9-42 Number of TLRs by TLR level by reliability coordinator: January through March, 2026[57]

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2026	MISO	9	3	0	2	4	0	18
	NYIS	0	0	0	0	0	0	0
	ONT	1	0	0	0	0	0	1
	PJM	1	1	0	0	0	0	2
	SOCO	21	41	0	0	0	0	62
	SWPP	37	54	0	4	3	0	98
	TVA	28	28	0	4	3	0	63
	VACS	2	8	0	0	0	0	10
Total		99	135	0	10	10	0	254

Up To Congestion Transactions

The original purpose, in 2000, of up to congestion transactions (UTC) was to allow market participants to submit a maximum congestion charge, up to $25 per MWh, they were willing to pay on an import, export or wheel through transaction in the day-ahead energy market. This product was offered as a tool for market participants to limit their congestion exposure on scheduled transactions in the real-time energy market.[58]

Up to congestion transactions affect the day-ahead dispatch and unit commitment. Despite that, up to congestion transactions were not required to pay uplift charges from their introduction in 2000 through October 31, 2020. On July 16, 2020, FERC issued an Order directing PJM to revise uplift allocation rules to allocate uplift to one side of up to congestion transactions.[59] The Order requires PJM to treat an up to congestion transaction, for uplift allocation purposes, as if the up to congestion transaction were equivalent to a DEC at its sink point. On November 1, 2020, PJM began allocating uplift to up to congestion transactions. Up to congestion transactions also negatively affect FTR funding.[60]

Figure 9-10 shows the monthly volume of cleared up to congestion transactions. Following an initial decline, UTC volumes had steadily increased following the allocation of uplift charges to UTCs effective November 1, 2020. However, the volume of cleared UTC transactions has declined again in the recent 12 month period to levels below what was seen prior to the allocation of uplift charges to UTCs. Table 9-43 shows the UTC volumes from the 12 month period prior to the allocation of uplift charges (November 1, 2019, through October 31, 2020), to the most recent 12 month period (April 1, 2025 through March 31, 2026). Table 9-44 shows the UTC volumes for the first three months of 2025 and 2026.

56 The total row in the columns of the number of unique flowgates that experience TLRs are not a sum of the individual months. The total row represents the number of unique flowgates that have experienced TLRs for the year to date.

57 Southern Company Services, Inc. (SOCO) is the reliability coordinator covering a portion of Mississippi, Alabama, Florida and Georgia. Southwest Power Pool (SWPP) is the reliability coordinator for SPP. VACAR-South (VACS) is the reliability coordinator covering a portion of North Carolina and South Carolina.

58 See the *2012 Annual State of the Market Report for PJM*, Volume 2, Section 8, "Interchange Transactions," for a more detailed discussion.

59 See 172 FERC ¶ 61,046.

60 See the *2026 Quarterly State of the Market Report for PJM: January through March*, Volume 2, Section 13: FTRs and ARRs, "FTR Forfeitures" for more information on up to congestion transaction impacts on FTRs.

Figure 9-10 Monthly up to congestion cleared bids in MWh: January 2005 through March 2026

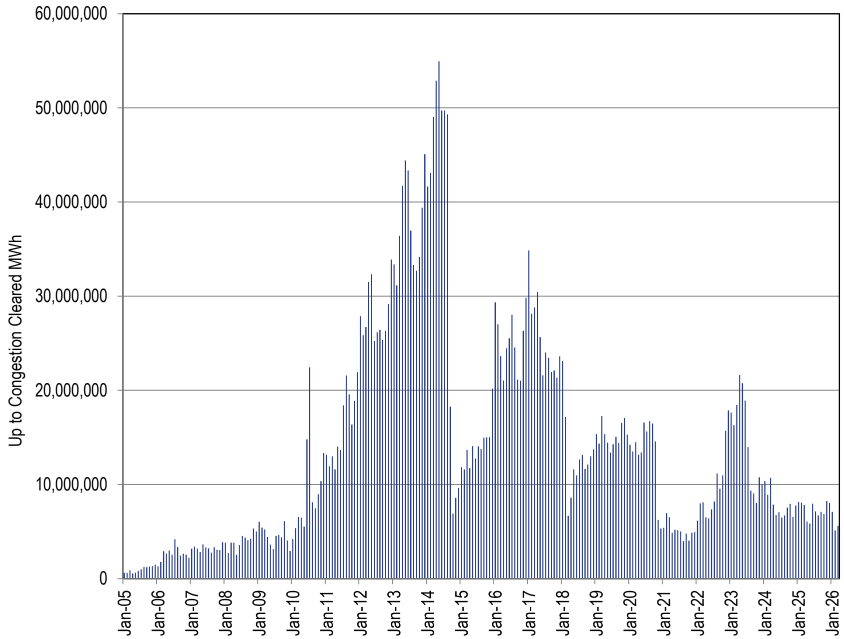


Table 9-43 Up to congestion volumes: November 1, 2019 through October 31, 2020 compared to April 1, 2025 through March 31, 2026

Category	November 1, 2019 - October 31, 2020	April 1, 2025 - March 31, 2026	Percent Change
Daily Average UTC Bids Submitted	53,368	55,124	3.3%
Daily Average UTC Bids Cleared	26,415	17,568	(33.5%)
Daily Average UTC Volume Submitted (MWh)	1,279,124	732,865	(42.7%)
Daily Average UTC Volume Cleared (MWh)	495,001	224,041	(54.7%)

Table 9-44 Up to congestion volumes: January through March, 2025 and 2026

Category	2025 (Jan-Mar)	2026 (Jan-Mar)	Percent Change
Daily Average UTC Bids Submitted	50,614	59,239	17.0%
Daily Average UTC Bids Cleared	19,607	18,239	(7.0%)
Daily Average UTC Volume Submitted (MWh)	834,422	661,666	(20.7%)
Daily Average UTC Volume Cleared (MWh)	266,942	197,997	(25.8%)

Table 9-45 shows the monthly cleared submitted volume of UTC bids from January 2025 through March 2026. In the first three months of 2026, the cleared MW volume of up to congestion transactions was comprised of 8.9 percent imports, 7.2 percent exports, 2.3 percent wheeling transactions and 81.6 percent internal transactions. Less than 0.1 percent of the up to congestion transactions had matching real-time energy market transactions

Table 9-45 Monthly volume of cleared and submitted up to congestion bids: January 2025 through March, 2026

	Bid MW					Bid Volume					Cleared MW					Cleared Volume				
Month	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total
Jan-25	2,205,672	2,182,123	334,327	21,101,450	25,823,572	125,604	187,964	18,092	1,300,404	1,632,064	464,114	701,211	108,021	6,876,908	8,150,254	32,413	91,771	6,004	547,475	677,663
Feb-25	2,455,996	2,513,637	359,618	18,056,777	23,386,028	114,520	183,212	32,050	1,036,986	1,366,768	748,465	537,412	144,845	6,633,542	8,064,264	41,822	54,750	11,534	428,231	536,337
Mar-25	3,118,908	1,826,595	278,735	20,664,128	25,888,366	170,467	150,970	20,393	1,214,563	1,556,393	678,923	587,700	152,636	6,391,031	7,810,290	46,728	57,345	7,116	439,419	550,608
Apr-25	2,179,369	789,354	341,206	17,872,615	21,182,544	169,667	95,947	17,035	1,156,357	1,439,006	397,841	217,089	149,400	5,294,497	6,058,826	35,760	26,334	4,065	373,011	439,170
May-25	1,300,945	867,919	224,558	13,954,428	16,347,850	105,869	85,547	12,625	966,859	1,170,900	363,478	312,867	120,464	5,044,292	5,841,101	24,841	20,884	3,267	324,995	373,987
Jun-25	1,814,662	1,402,459	171,331	19,928,093	23,316,546	144,615	104,586	12,351	1,229,721	1,491,273	590,128	292,998	81,725	6,988,373	7,953,223	56,190	26,403	3,754	483,442	569,789
Jul-25	2,271,084	1,445,784	259,642	17,998,508	21,975,019	186,792	125,712	18,569	1,327,626	1,658,699	678,823	266,906	74,374	6,118,292	7,138,395	79,167	25,831	5,399	568,717	679,114
Aug-25	2,006,277	1,591,872	280,230	15,399,345	19,277,724	146,474	122,446	18,102	1,053,784	1,340,806	702,076	328,270	99,923	5,580,230	6,710,499	55,827	27,995	5,273	408,458	497,553
Sep-25	1,417,219	2,117,739	234,451	20,273,139	24,042,548	154,729	134,822	15,782	1,410,148	1,715,481	328,860	509,245	75,506	6,174,356	7,087,967	39,739	30,513	3,961	459,532	533,745
Oct-25	2,294,262	1,725,906	298,136	24,115,429	28,433,733	207,538	154,738	18,313	1,571,545	1,952,134	579,361	431,763	74,185	5,786,974	6,872,283	39,887	28,416	3,242	419,644	491,189
Nov-25	3,349,574	2,372,416	257,628	21,554,060	27,533,679	237,736	187,705	31,356	1,539,524	1,996,321	1,123,674	582,248	85,796	6,459,803	8,251,521	62,226	36,476	7,097	445,376	551,175
Dec-25	2,400,545	2,477,093	435,950	20,522,594	25,836,182	168,969	200,533	37,869	1,616,942	2,024,313	821,302	425,578	121,214	6,673,259	8,041,354	54,968	41,635	8,527	529,865	634,995
2025	26,814,513	21,312,899	3,475,813	231,440,566	283,043,791	1,932,980	1,734,182	252,537	15,424,459	19,344,158	7,477,043	5,193,286	1,288,089	74,021,558	87,979,977	569,568	468,353	69,239	5,428,165	6,535,325
Jan-26	2,265,086	2,243,339	485,784	18,221,249	23,215,458	137,118	216,957	32,754	1,689,545	2,076,374	534,932	594,229	187,170	5,770,543	7,086,873	32,959	48,865	9,279	502,567	593,670
Feb-26	1,690,605	1,507,364	339,147	13,213,361	16,750,477	106,538	190,772	25,333	1,424,877	1,747,520	475,958	354,252	121,860	4,166,854	5,118,923	28,378	40,372	6,379	488,272	563,401
Mar-26	2,510,867	1,603,024	215,936	15,254,141	19,583,967	153,974	139,579	16,836	1,197,203	1,507,592	582,549	331,435	103,202	4,596,758	5,613,943	37,791	25,882	4,408	416,351	484,432
2026	6,466,558	5,353,727	1,040,867	46,688,751	59,549,902	397,630	547,308	74,923	4,311,625	5,331,486	1,593,438	1,279,916	412,231	14,534,155	17,819,739	99,128	115,119	20,066	1,407,190	1,641,503

Sham Scheduling

Sham scheduling refers to a scheduling method under which a market participant breaks a single transaction, from generation balancing authority (source) to load balancing authority (sink), into multiple segments. Sham scheduling hides the actual source of generation from the load balancing authority. When unable to identify the source of the energy, the load balancing authority cannot see how the power will flow to the load, which can create loop flows and result in inaccurate pricing for transactions.

For example, if the generation balancing authority (source) is NYISO, and the load balancing authority (sink) is PJM, the transaction would be priced, in the PJM energy market, at the PJM/NYIS Interface regardless of the submitted path. However, if a market participant were to break the transaction into multiple segments, one on the NYIS-ONT path, and a second segment on the ONT-MISO-PJM path, the market participant would conceal the true source (NYISO) from PJM, and PJM would price the transaction as if its source were Ontario (the ONT interface price).

Sham scheduling can also be achieved by submitting a transaction that is in the opposite direction of a portion of a larger transaction schedule.

For example, market participants can submit one transaction with multiple segments among balancing authorities and another transaction which offsets all or part of a segment of the first transaction. If a market participant submits two separate transactions, one on the ONT-MISO-PJM path, and a second on the PJM-MISO path, the result of these transactions would be a net scheduled transaction from ONT to MISO, as the MISO-PJM segment of the first transaction is offset by the PJM-MISO transaction. In this example, PJM is not required to raise or lower generation as a result of these transactions, as they would for an import or an export, and there are no associated power flows across PJM. Nonetheless, the market participant is paid the price difference between the PJM/ONT interface pricing point and the PJM/MISO interface pricing point. The market participant would be paid the PJM/ONT interface pricing point for the first transaction (ONT to PJM import) and the market participant would pay the PJM/MISO interface pricing point for the second transaction (PJM to MISO export). If the PJM/ONT interface price were higher than the PJM/MISO interface price, the market participant would be paid a net profit from the PJM market even though there was no impact on PJM operations.

At the April 10, 2013, PJM Market Implementation Committee (MIC), the MMU presented a problem statement and issue charge to address sham scheduling activities.[61] The expected deliverables from the stakeholder meetings were revisions to the Tariff and PJM business manuals. The topic was discussed at several MIC meetings. While there was stakeholder agreement that sham scheduling activity was inappropriate, consensus on revised tariff and manual language was not achieved. The topic was closed. The MMU clarified that it would continue to monitor transactions for sham scheduling activities and that the MMU could refer market participants for sham scheduling activities.

The MMU monitors for sham scheduling activities on a daily basis. Following the stakeholder discussions in 2013, the net profits obtained from sham scheduling activities fell by 102.2 percent, from net profits of $15.5 million in 2014, to a net loss of $339,150 in 2025. The total number of hours of sham scheduling segments where the MW profile matched exactly across all segments of the path combinations in the same hour fell by 79.0 percent, from 1,898 hours in 2014 to 398 hours in 2025.

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.

Elimination of Ontario Interface Pricing Point

The PJM/IMO interface pricing point (Ontario) was created to reflect the fact that transactions that originate or sink in the IESO balancing authority create actual energy flows that are split between the MISO and NYISO interface pricing points. PJM created the PJM/IMO interface pricing point to reflect the actual power flows across both the MISO/PJM and NYISO/PJM Interfaces. The IMO does not have physical ties with PJM because it is not contiguous.

Prior to June 1, 2015, the PJM/IMO interface pricing point was defined as the LMP at the IESO Bruce bus. The LMP at the Bruce bus includes a congestion and loss component across the MISO and NYISO balancing authorities.

The noncontiguous nature of the PJM/IMO interface pricing point creates opportunities for market participants to engage in sham scheduling activities.[62] For example, a market participant can use two separate transactions to create a flow from Ontario to MISO. In this example, the market participant uses the PJM energy market as a temporary generation and load point by first submitting a wheeling transaction from Ontario, through MISO and into PJM, then by submitting a second transaction from PJM to MISO. These two transactions, combined, create an actual flow along the Ontario/MISO Interface. Through sham scheduling, the market participant receives settlements from PJM when no changes in generation occur. This activity is similar to that observed when PJM had a Southwest and Southeast interface pricing point. During that time, market participants would use the PJM spot market as a temporary load and generation point to wheel transactions through the PJM energy market. This

61 *See* Market Path/Interface Pricing Point alignment Problem Statement, at: <http://www.monitoringanalytics.com/reports/Presentations/2013/IMM_MIC_Market_Path_Interface_Pricing_Point_Alignment_Problem_Statement_201304010.pdf>.

62 *See* "Sham Scheduling," Presented at the PJM Market Monitoring Unit Advisory Committee (MMUAC) meeting held on December 6, 2013 <http://www.monitoringanalytics.com/reports/Presentations/2013/IMM_Sham_Scheduling_20131206.pdf>.

was done to take advantage of the price differences between the interfaces without providing the market benefits of congestion relief.

A new PJM/IMO interface price method was implemented on June 1, 2015. The new method uses a dynamic weighting of the PJM/MISO interface price and the PJM/NYIS interface price, based on the performance of the Michigan-Ontario PARs. When the absolute value of the actual flows on the PARs are greater than or equal to the absolute value of the scheduled flows on the PARs, and the scheduled and actual flows are in the same direction, the PJM/IMO interface price will be equal to the PJM/MISO interface price (i.e. 100 percent weighting on the PJM/MISO Interface). When actual flows on the PARs are in the opposite direction of the scheduled flows on the PARs, the PJM/IMO interface price will be equal to the PJM/NYIS interface price (i.e.

100 percent weighting on the PJM/NYIS Interface). When the absolute value of the actual flows on the PARs are less than or equal to the absolute value of the scheduled flows on the PARs, and the scheduled and actual flows are in the same direction, the PJM/IMO interface price will be a combination to the PJM/MISO interface price and the PJM/NYIS interface price. In this case the weightings of the PJM/MISO and PJM/NYIS interface prices are determined based on the scheduled and actual flows. For example, in a given interval, the scheduled flow on the Michigan-Ontario PARs is 1,000 MW, and the actual flow is 800 MW. If in that same interval, the PJM/MISO interface price is $45.00 and the PJM/NYIS interface price $30.00, the PJM/IMO interface price would be calculated with a weighting of 80 percent of the PJM/MISO interface price ($45.00 * 0.8, or $36.00) and 20 percent of the PJM/NYIS interface price ($30.00 * 0.2, or $6.00), for a PJM/IMO interface price of $42.00.

The MMU believes that the new PJM/IMO interface price method is a step in the right direction towards pricing energy that sources or sinks in Ontario based on the path of the actual, physical transfer of energy. The MMU remains concerned about the assumption of PAR operations, and will continue to evaluate the impact of PARs on the scheduled and actual flows and the impacts on the PJM/IMO interface price. The MMU remains concerned about the potential for market participants to continue to engage in sham scheduling activities after the new method is implemented.

The MMU recommends that if the PJM/IMO interface price remains and with PJM's new method in place, that PJM implement additional business rules to remove the incentive to engage in sham scheduling activities using the PJM/IMO interface price. Such rules would prohibit the same market participant from scheduling an export transaction from PJM to any balancing authority while at the same time an import transaction is scheduled to PJM that receives the PJM/IMO interface price. PJM should also prohibit the same market participant from scheduling an import transaction to PJM from any balancing authority while at the same time an export transaction is scheduled from PJM that receives the PJM/IMO interface price.

In the first three months of 2026, there were 273.5 GWh of net scheduled transactions between PJM and IESO. The net scheduled transactions were made up of 316.3 GWh of imports wheeled through MISO, and 42.9 GWh of exports wheeled through the NYISO. (Table 9-25). The MMU recommends that PJM eliminate the PJM/IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing authority to the PJM/MISO interface pricing point.[63]

PJM and NYISO Coordinated Interchange Transactions

Coordinated transaction scheduling (CTS) provides the option for market participants to submit intra-hour transactions between the NYISO and PJM that include an interface spread bid on which transactions are evaluated.[64] The evaluation is based on the forward-looking prices as determined by PJM's intermediate term security constrained economic dispatch tool (IT SCED) and the NYISO's real-time commitment (RTC) tool. PJM shares its PJM/NYISO interface price IT SCED results with the NYISO. The NYISO compares the PJM/NYISO interface price with its RTC calculated NYISO/PJM interface price. If the PJM and NYISO interface price spread is greater than the market participant's CTS bid, the transaction is approved. If the PJM and NYISO interface price spread is less than the CTS bid, the transaction is denied.

63 On October 1, 2013, a sub-group of PJM's Market Implementation Committee started stakeholder discussions to address this inconsistency in market pricing.

64 PJM and the NYISO implemented CTS on November 4, 2014. 146 FERC ¶ 61,096 (2014).

The IT SCED application runs every five minutes and each run produces forecast LMPs for the intervals approximately 30 minutes, 45 minutes, 90 minutes and 135 minutes ahead. Therefore, for each 15 minute interval, the various IT SCED solutions will produce 12 forecasted PJM/NYIS interface prices. To evaluate the accuracy of IT SCED forecasts, the forecasted PJM/NYIS interface price for each 15 minute interval from IT SCED was compared to the actual real-time interface LMP in the first three months of 2026. Table 9-46 shows that over all 12 forecast ranges, IT SCED predicted the real-time PJM/NYIS interface LMP within the range of $0.00 to $5.00 in 21.1 percent of the intervals. In those intervals, the average price difference between the IT SCED forecasted LMP and the actual real-time LMP was $2.11 per MWh. In 31.0 percent of all intervals, the absolute value of the average price difference between the IT SCED forecasted LMP and the actual real-time interface LMP was greater than $20.00. The average price differences were $88.73 when the price difference was greater than $20.00, and $99.58 when the price difference was greater than -$20.00.

Table 9-46 Differences between forecast and actual PJM/NYIS interface prices: January through March, 2026

Range of Price Differences	Percent of All Intervals	Average Price Difference
> $20	16.4%	$88.73
$10 to $20	7.6%	$14.20
$5 to $10	9.4%	$7.19
$0 to $5	21.1%	$2.11
$0 to -$5	17.9%	$2.07
-$5 to -$10	7.0%	$7.13
-$10 to -$20	6.0%	$14.14
< -$20	14.6%	$99.58

Table 9-47 shows how the accuracy of the IT SCED forecasted LMPs changes as the cases approach real-time. In the final IT SCED results prior to real time, in 35.3 percent of all intervals, the average price difference between the IT SCED forecasted LMP and the actual real-time interface LMP fell within +/- $5.00 of the actual PJM/NYIS interface real-time LMP, compared to 39.8 percent in the 135 minute ahead IT SCED results.

Table 9-47 Differences between forecast and actual PJM/NYIS interface prices: January through March, 2026

	~ 135 Minutes Prior to Real-Time		~ 90 Minutes Prior to Real-Time		~ 45 Minutes Prior to Real-Time		~ 30 Minutes Prior to Real-Time	
Range of Price Differences	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference
> $20	20.0%	$94.83	13.8%	$73.53	15.2%	$84.02	18.7%	$102.96
$10 to $20	7.2%	$14.30	7.2%	$14.13	7.7%	$14.13	7.8%	$14.09
$5 to $10	9.0%	$7.21	9.3%	$7.12	9.4%	$7.21	9.0%	$7.19
$0 to $5	21.2%	$2.00	22.2%	$2.05	20.5%	$2.14	19.0%	$2.27
$0 to -$5	18.5%	$2.06	18.7%	$1.97	17.6%	$2.14	16.3%	$2.18
-$5 to -$10	6.7%	$7.24	7.7%	$7.16	7.5%	$7.07	7.1%	$7.08
-$10 to -$20	5.0%	$14.13	6.2%	$14.02	6.3%	$14.18	6.5%	$14.32
< -$20	12.3%	$98.08	14.9%	$98.35	15.8%	$99.54	15.5%	$103.59

In 34.1 percent of the intervals in the 30 minute ahead forecast, the absolute value of the average price difference between the IT SCED forecasted LMP and the actual real-time interface LMP was greater than $20.00. The average price difference was $102.96 when the price difference was greater than $20.00, and $103.59 when the price difference was greater than -$20.00.

Table 9-48 and Table 9-49 show the monthly differences between forecasted and actual PJM/NYIS interface prices. Analysis of the data on a monthly basis shows that there is a decline in the accuracy of the IT SCED forecast during periods of cold and hot weather.

Table 9-48 Monthly Differences between forecast and actual PJM/NYIS interface prices (percent of intervals): January through March, 2026

Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	21.1%	21.6%	13.6%	18.7%
	$10 to $20	6.0%	6.9%	10.5%	7.8%
	$5 to $10	7.3%	7.1%	12.4%	9.0%
	$0 to $5	19.3%	15.9%	21.5%	19.0%
	$0 to -$5	17.0%	17.0%	15.0%	16.3%
	-$5 to -$10	6.4%	7.5%	7.5%	7.1%
	-$10 to -$20	6.2%	6.3%	7.1%	6.5%
	< -$20	16.7%	17.6%	12.4%	15.5%
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	16.9%	18.4%	10.7%	15.2%
	$10 to $20	6.7%	6.7%	9.8%	7.7%
	$5 to $10	7.7%	7.2%	13.0%	9.4%
	$0 to $5	21.3%	17.3%	22.4%	20.5%
	$0 to -$5	17.4%	18.5%	17.0%	17.6%
	-$5 to -$10	6.8%	7.9%	7.9%	7.5%
	-$10 to -$20	6.1%	6.4%	6.5%	6.3%
	< -$20	17.1%	17.5%	12.8%	15.8%
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	16.8%	15.5%	9.2%	13.8%
	$10 to $20	6.3%	6.9%	8.5%	7.2%
	$5 to $10	7.9%	7.6%	12.2%	9.3%
	$0 to $5	21.4%	19.3%	25.7%	22.2%
	$0 to -$5	18.9%	19.5%	17.7%	18.7%
	-$5 to -$10	7.1%	7.3%	8.5%	7.7%
	-$10 to -$20	6.1%	6.2%	6.2%	6.2%
	< -$20	15.3%	17.6%	12.0%	14.9%
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	21.1%	22.9%	16.3%	20.0%
	$10 to $20	6.6%	6.1%	8.9%	7.2%
	$5 to $10	8.5%	7.1%	11.3%	9.0%
	$0 to $5	20.4%	18.6%	24.5%	21.2%
	$0 to -$5	18.5%	19.0%	18.1%	18.5%
	-$5 to -$10	6.7%	6.6%	6.8%	6.7%
	-$10 to -$20	5.3%	5.4%	4.3%	5.0%
	< -$20	12.8%	14.3%	9.8%	12.3%

Table 9-49 Monthly differences between forecast and actual PJM/NYIS interface prices (average price difference): January through March, 2026

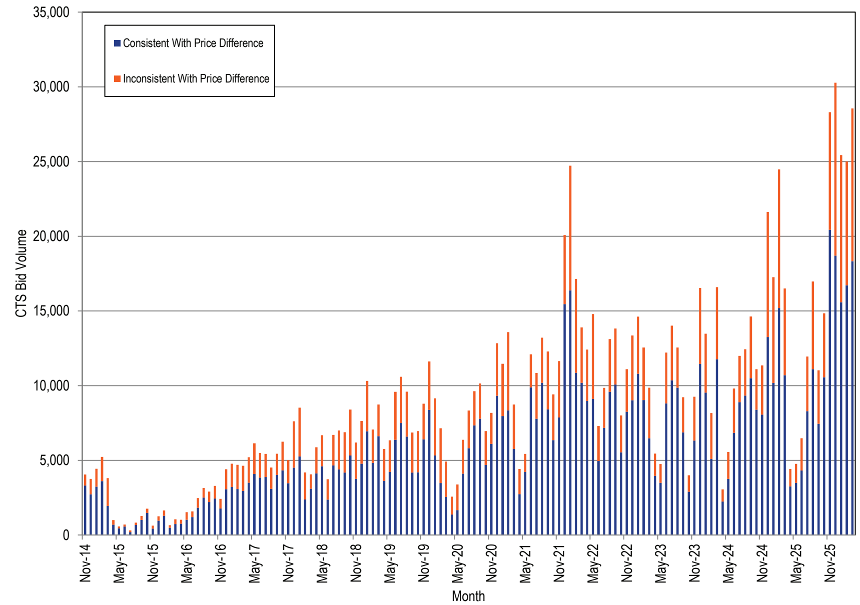
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	$93.34	$148.45	$52.70	$102.96
	$10 to $20	$14.39	$13.98	$13.98	$14.09
	$5 to $10	$7.04	$7.30	$7.22	$7.19
	$0 to $5	$2.11	$2.14	$2.49	$2.27
	$0 to -$5	$2.05	$2.25	$2.26	$2.18
	-$5 to -$10	$7.11	$6.99	$7.13	$7.08
	-$10 to -$20	$14.51	$14.44	$14.07	$14.32
	< -$20	$95.72	$117.85	$95.89	$103.59
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	$86.41	$105.31	$47.11	$84.02
	$10 to $20	$14.22	$14.25	$13.99	$14.13
	$5 to $10	$7.30	$7.03	$7.25	$7.21
	$0 to $5	$2.05	$2.06	$2.27	$2.14
	$0 to -$5	$1.98	$2.21	$2.23	$2.14
	-$5 to -$10	$6.95	$7.14	$7.12	$7.07
	-$10 to -$20	$14.29	$14.59	$13.70	$14.18
	< -$20	$89.97	$114.86	$93.38	$99.54
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	$80.31	$81.46	$49.05	$73.53
	$10 to $20	$14.06	$14.14	$14.18	$14.13
	$5 to $10	$7.09	$7.12	$7.14	$7.12
	$0 to $5	$1.98	$2.02	$2.12	$2.05
	$0 to -$5	$1.82	$2.03	$2.08	$1.97
	-$5 to -$10	$7.09	$7.26	$7.14	$7.16
	-$10 to -$20	$14.13	$14.25	$13.71	$14.02
	< -$20	$86.21	$112.64	$94.88	$98.35
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	$101.85	$104.24	$73.73	$94.83
	$10 to $20	$14.49	$14.32	$14.14	$14.30
	$5 to $10	$7.28	$7.17	$7.19	$7.21
	$0 to $5	$1.86	$1.87	$2.21	$2.00
	$0 to -$5	$1.97	$2.09	$2.11	$2.06
	-$5 to -$10	$7.13	$7.22	$7.38	$7.24
	-$10 to -$20	$14.11	$14.54	$13.69	$14.13
	< -$20	$84.07	$109.62	$101.18	$98.08

The NYISO uses PJM's IT SCED forecasted LMPs to compare against the NYISO Real-Time Commitment (RTC) results in its evaluation of CTS transactions. The NYISO approves CTS (spread bid) transactions when the offered spread is less than or equal to the spread between the IT SCED forecast PJM/NYIS interface LMP and the NYISO RTC forecast NYIS/PJM interface LMP. The large differences between forecast and actual LMPs in the intervals closest to real-time could cause CTS transactions to be approved that would contribute to transactions being scheduled counter to real-time economic signals, and contribute to inefficient scheduling across the PJM/NYIS border.

CTS transactions are evaluated based on the spread bid, which limits the amount of price convergence that can occur. As long as balancing operating reserve charges are applied and CTS transactions are optional, the CTS proposal represents a small incremental step toward better interface pricing. The NYISO has a 75 minute bid submission deadline. While market participants have the option to specify bid data on 15 minute intervals, market participants must submit their bids 75 minutes prior to the requested transaction start time. The 75 minute bid submission deadline associated with scheduling energy transactions in the NYISO should be shortened. Reducing this deadline could significantly improve pricing efficiency at the PJM/NYISO border for non-CTS transactions and for CTS transactions as market participants would be able to adjust their bids in response to real-time price signals.

CTS transactions were evaluated for each 15 minute interval. From November 4, 2014, through March 31, 2026, 1,212,688 15 minute CTS schedules were approved through the CTS process based on the forecast LMPs. When the forecast LMPs for the approved intervals were compared to the hourly integrated real-time LMPs, the direction of the flow in 382,387 (31.5 percent) of the intervals was inconsistent with the differences in real-time PJM/NYISO and NYISO/PJM prices. For example, if a market participant submits a CTS transaction from NYISO to PJM with a spread bid of $5.00, and NYISO's forecasted PJM interface price was at least $5.00 lower than PJM's forecasted NYISO interface price, the transaction would be approved. For 31.5 percent of the approved transactions, the actual, real-time price differentials were in the opposite direction of the forecast differential. The actual, real-time price differentials meant that the transactions would have been economic in the opposite direction. For 68.5 percent of the intervals, the forecast price differentials were consistent with real-time PJM/NYISO and NYISO/PJM price differences. Figure 9-11 shows the monthly volume of cleared PJM/NYIS CTS bids. Figure 9-11 also shows the percent of cleared bids that resulted in flows consistent and inconsistent with price differences.

Figure 9-11 Monthly cleared PJM/NYIS CTS bid volume: November 4, 2014 through March 31, 2026



The data reviewed show that IT SCED is not a highly accurate predictor of the real-time PJM/NYIS interface prices. This limits the effectiveness of CTS in improving interface pricing between PJM and NYISO.

Reserving Ramp on the PJM/NYISO Interface

Prior to the implementation of CTS, PJM held ramp space for all transactions submitted between PJM and the NYISO as soon as the NERC Tag was approved. At that time, once transactions were evaluated by the NYISO through their real-time market clearing process, any adjustments made to the submitted transactions would be reflected on the NERC Tags and the PJM ramp was adjusted accordingly.

As part of this process, PJM was often required to make adjustments to transactions on its other interfaces in order to bring total system ramp back to within its limit. The default ramp limit in PJM is +/- 1,000 MW. For example, the ramp in a given interval is currently -1,000 MW, consisting of 2,000 MW of imports from the NYISO to PJM and 3,000 MW of exports from PJM on its other interfaces. If, through the NYISO real-time market clearing process, the NYISO only approves 1,000 MW of the imports, the other 1,000 MW of import transactions from the NYISO would be curtailed. The ramp in this interval would then be -2,000 MW, consisting of the 1,000 MW of cleared imports from the NYISO to PJM and 3,000 MW of exports from PJM on its other interfaces. PJM would then be required to curtail an additional 1,000 MW of exports at its other interface to bring the limit back to within +/- 1,000. These curtailments were made on a last in first out basis as determined by the timestamp on the NERC Tag.

With the implementation of the CTS product with the NYISO, PJM modified how ramp is handled at the PJM/NYISO Interface. Effective November 4, 2014, PJM no longer holds ramp room for any transactions submitted between PJM and the NYISO at the time of submission. Only after the NYISO completes its real-time market clearing process, and communicates the results to PJM, does PJM perform a ramp evaluation on transactions scheduled with the NYISO. If, in the event the NYISO market clearing process would violate ramp, PJM would make additional adjustments based on a last-in first-out basis as determined by the timestamp on the NERC Tag. This process prevents the transactions scheduled at the PJM/NYISO Interface from holding (or creating) ramp until NYISO has completed its economic evaluation and the transactions are approved through the NYISO market clearing process.

PJM and MISO Coordinated Interchange Transaction Proposal

PJM and MISO proposed the implementation of coordinated interchange transactions, similar to the PJM/NYISO approach, through the Joint and Common Market Initiative. The PJM/MISO coordinated transaction scheduling (CTS) process provides the option for market participants to submit intra-hour transactions between the MISO and PJM that include an interface spread bid on which transactions are evaluated. Similar to the PJM/NYISO approach, the evaluation is based, in part, on the forward-looking prices as determined by PJM's intermediate term security constrained economic dispatch tool (IT SCED). Unlike the PJM/NYISO CTS process in which the NYISO performs the evaluation, the PJM/MISO CTS process uses a joint clearing process in which both RTOs share forward looking prices. On October 3, 2017, PJM and MISO implemented the CTS process.

The IT SCED application runs every five minutes and each run produces forecast LMPs for the intervals approximately 30 minutes, 45 minutes, 90 minutes and 135 minutes ahead. Therefore, for each 15 minute interval, the various IT SCED solutions will produce 12 forecasted PJM/MISO interface prices. To evaluate the accuracy of IT SCED forecasts, the forecasted PJM/MISO interface price for each 15 minute interval from IT SCED was compared to the actual real-time interface LMP for the first three months of 2026. Table 950 shows that over all 12 forecast ranges, IT SCED predicted the real-time PJM/MISO interface LMP within the range of $0.00 to $5.00 in 23.4 percent of all intervals. In those intervals, the average price difference between the IT SCED forecasted LMP and the actual real-time LMP was $2.22. In 26.1 percent of all intervals, the absolute value of the average price difference between the IT SCED forecasted LMP and the actual real-time interface LMP was greater than $20.00. The average price differences were $79.17 when the price difference was greater than $20.00, and $99.17 when the price difference was greater than -$20.00.

Table 9-50 Differences between forecast and actual PJM/MISO interface prices: January through March, 2026

Range of Price Differences	Percent of All Intervals	Average Price Difference
> $20	17.3%	$79.17
$10 to $20	9.2%	$14.07
$5 to $10	11.9%	$7.17
$0 to $5	23.4%	$2.22
$0 to -$5	18.2%	$2.00
-$5 to -$10	6.3%	$7.20
-$10 to -$20	4.9%	$14.10
< -$20	8.9%	$99.17

Table 9-51 shows how the accuracy of the IT SCED forecasted LMPs change as the cases approach real-time. In the final IT SCED results prior to real-time, in 38.2 percent of all intervals, the average price difference between the IT SCED forecasted LMP and the actual real-time interface LMP fell within +/- $5.00 of the actual PJM/MISO interface real-time LMP, compared to 42.2 percent in the 135 minute ahead IT SCED results.

Table 9-51 Differences between forecast and actual PJM/MISO interface prices: January through March, 2026

	~ 135 Minutes Prior to Real-Time		~ 90 Minutes Prior to Real-Time		~ 45 Minutes Prior to Real-Time		~ 30 Minutes Prior to Real-Time	
Range of Price Differences	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference
> $20	19.6%	$96.60	14.6%	$66.11	17.0%	$74.49	19.9%	$82.76
$10 to $20	9.1%	$14.14	8.9%	$14.11	9.0%	$13.98	8.8%	$14.19
$5 to $10	11.8%	$7.19	11.8%	$7.11	12.1%	$7.14	11.1%	$7.24
$0 to $5	24.2%	$2.18	26.2%	$2.17	22.4%	$2.20	19.8%	$2.25
$0 to -$5	18.0%	$1.95	17.9%	$1.97	18.3%	$2.03	18.4%	$2.15
-$5 to -$10	5.8%	$7.11	6.3%	$7.16	6.3%	$7.25	7.2%	$7.28
-$10 to -$20	4.2%	$14.03	5.0%	$13.68	5.3%	$14.10	5.1%	$14.30
< -$20	7.3%	$99.28	9.3%	$97.11	9.4%	$98.88	9.7%	$97.18

In 29.6 percent of the intervals in the 30 minute ahead forecast, the absolute value of the average price difference between the IT SCED forecasted LMP and the actual real-time interface LMP was greater than $20.00, the average price differences were $82.76 when the price difference was greater than $20.00, and $97.18 when the price difference was greater than -$20.00.

Table 9-52 and Table 9-53 show the monthly differences between forecasted and actual PJM/MISO interface prices. Analysis of the data on a monthly basis shows that there is a decline in the accuracy of the IT SCED forecast during periods of cold and hot weather.

Table 9-52 Monthly differences between forecast and actual PJM/MISO interface prices (percent of intervals): January through March, 2026

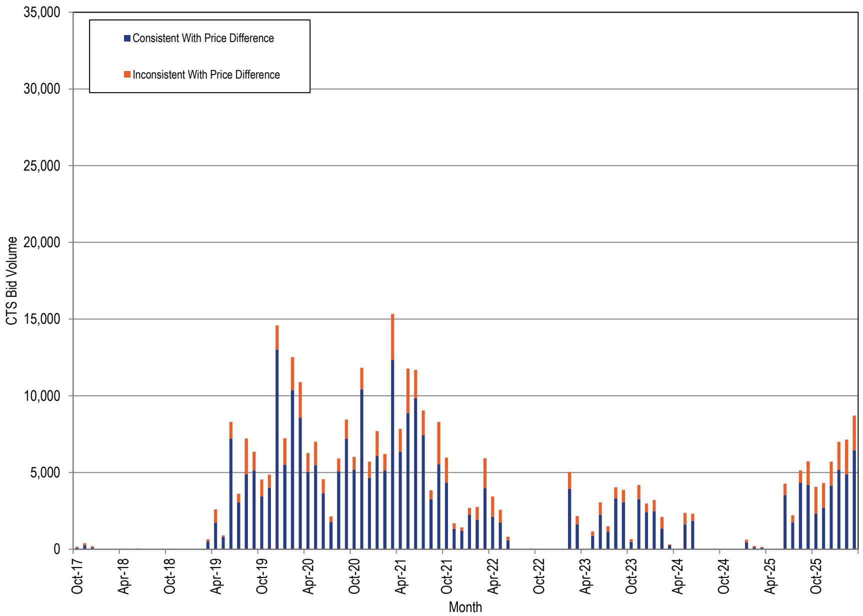
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	20.3%	21.4%	18.3%	19.9%
	$10 to $20	6.6%	9.4%	10.4%	8.8%
	$5 to $10	9.4%	11.0%	13.1%	11.1%
	$0 to $5	21.1%	18.9%	19.3%	19.8%
	$0 to -$5	21.0%	18.1%	16.1%	18.4%
	-$5 to -$10	7.3%	6.5%	7.8%	7.2%
	-$10 to -$20	4.7%	4.8%	5.8%	5.1%
	< -$20	9.7%	10.0%	9.3%	9.7%
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	18.5%	18.3%	14.3%	17.0%
	$10 to $20	6.3%	9.3%	11.5%	9.0%
	$5 to $10	10.5%	10.8%	14.8%	12.1%
	$0 to $5	24.3%	21.6%	21.4%	22.4%
	$0 to -$5	20.1%	18.5%	16.4%	18.3%
	-$5 to -$10	6.4%	6.2%	6.5%	6.3%
	-$10 to -$20	4.7%	5.2%	6.0%	5.3%
	< -$20	9.2%	10.1%	9.0%	9.4%
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	17.3%	14.6%	11.9%	14.6%
	$10 to $20	6.7%	8.9%	11.3%	8.9%
	$5 to $10	9.6%	10.4%	15.3%	11.8%
	$0 to $5	27.3%	25.2%	25.8%	26.2%
	$0 to -$5	19.5%	18.6%	15.7%	17.9%
	-$5 to -$10	6.2%	6.8%	5.9%	6.3%
	-$10 to -$20	4.8%	5.0%	5.2%	5.0%
	< -$20	8.7%	10.4%	8.9%	9.3%
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	21.1%	20.5%	17.1%	19.6%
	$10 to $20	6.8%	8.5%	12.1%	9.1%
	$5 to $10	11.1%	9.6%	14.4%	11.8%
	$0 to $5	24.3%	24.6%	23.8%	24.2%
	$0 to -$5	20.6%	18.3%	15.2%	18.0%
	-$5 to -$10	5.4%	5.9%	6.1%	5.8%
	-$10 to -$20	3.9%	4.7%	4.1%	4.2%
	< -$20	6.9%	7.9%	7.2%	7.3%

Table 9-53 Monthly differences between forecast and actual PJM/MISO interface prices (average price difference): January through March, 2026

Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	$81.23	$106.70	$59.19	$82.76
	$10 to $20	$14.19	$14.06	$14.31	$14.19
	$5 to $10	$7.07	$7.28	$7.32	$7.24
	$0 to $5	$2.12	$2.19	$2.44	$2.25
	$0 to -$5	$2.00	$2.20	$2.27	$2.15
	-$5 to -$10	$7.22	$7.37	$7.27	$7.28
	-$10 to -$20	$14.31	$14.55	$14.11	$14.30
	< -$20	$82.86	$92.35	$116.82	$97.18
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	$84.29	$78.53	$57.15	$74.49
	$10 to $20	$13.93	$14.06	$13.95	$13.98
	$5 to $10	$7.02	$7.22	$7.18	$7.14
	$0 to $5	$2.04	$2.20	$2.39	$2.20
	$0 to -$5	$1.81	$2.17	$2.16	$2.03
	-$5 to -$10	$7.02	$7.40	$7.34	$7.25
	-$10 to -$20	$14.42	$14.33	$13.66	$14.10
	< -$20	$85.44	$91.27	$120.35	$98.88
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	$85.36	$56.94	$48.21	$66.11
	$10 to $20	$14.35	$14.28	$13.85	$14.11
	$5 to $10	$7.11	$7.16	$7.08	$7.11
	$0 to $5	$2.11	$2.07	$2.33	$2.17
	$0 to -$5	$1.88	$1.96	$2.09	$1.97
	-$5 to -$10	$7.10	$7.23	$7.14	$7.16
	-$10 to -$20	$13.71	$13.61	$13.71	$13.68
	< -$20	$80.08	$89.62	$121.70	$97.11
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	$110.18	$88.89	$88.14	$96.60
	$10 to $20	$14.09	$14.21	$14.13	$14.14
	$5 to $10	$7.26	$7.19	$7.14	$7.19
	$0 to $5	$2.07	$2.14	$2.33	$2.18
	$0 to -$5	$1.85	$2.01	$2.02	$1.95
	-$5 to -$10	$7.03	$7.12	$7.18	$7.11
	-$10 to -$20	$13.94	$14.03	$14.13	$14.03
	< -$20	$78.44	$85.15	$133.45	$99.28

CTS transactions were evaluated for each interval. From October 3, 2017, through March 31, 2026, 346,867 CTS schedules were approved through the CTS process based on the forecast LMPs. When the forecast LMPs for the approved intervals were compared to the hourly integrated real-time LMPs, the direction of the flow in 74,554 (21.5 percent) of the intervals was inconsistent with the differences in real-time PJM/MISO and MISO/PJM prices. For example, if a market participant submits a CTS transaction from MISO to PJM with a spread bid of $5.00, and MISO's forecasted PJM interface price was at least $5.00 lower than PJM's forecasted MISO interface price, the transaction would be approved. For 21.5 percent of the approved transactions, the actual, real-time price differentials were in the opposite direction of the forecast differential. The actual, real-time price differentials meant that the transactions would have been economic in the opposite direction. For 78.5 percent of the intervals, the forecast price differentials were consistent with real-time PJM/MISO and MISO/PJM price differences. Figure 912 shows the monthly volume of cleared PJM/MISO CTS bids. Figure 912 also shows the percent of cleared bids that resulted in flows consistent and inconsistent with price differences. In June 2022, MISO experienced software issues that prevented the submission and clearing of CTS transactions. The issue was resolved in August 2022. It is unclear why market participants did not resume scheduling CTS transactions at the MISO interface until February 2023. Market participants did not use the MISO CTS transaction option between June 2024 and January 2025. While the forecast LMPs have not proven to be a good predictor of real time LMPs, that has not changed. It is not clear why market participants stopped using the MISO CTS transaction option during that time, or have not resumed using the option at volumes previously used.

Figure 9-12 Monthly cleared PJM/MISO CTS bid volume: October 3, 2017 through March 31, 2026



The data reviewed show that IT SCED is not a highly accurate predictor of the real-time PJM/MISO interface prices. This limits the effectiveness of CTS in improving interface pricing between PJM and MISO.

Willing to Pay Congestion and Not Willing to Pay Congestion

When reserving nonfirm transmission, market participants have the option to choose whether or not they are willing to pay congestion. When the market participant elects to pay congestion, PJM operators redispatch the system if necessary to allow the energy transaction to continue to flow. The system redispatch often creates price separation across buses on the PJM system. The difference in LMPs between two buses in PJM is the congestion cost (and losses) that the market participant pays in order for their transaction to continue to flow.

The MMU recommended that PJM modify the not willing to pay congestion product to address the issues of uncollected congestion charges. The MMU recommended charging market participants for any congestion incurred while the transaction is loaded, regardless of their election of transmission service, and restricting the use of not willing to pay congestion transactions (as well as all other real-time external energy transactions) to transactions at interfaces.

On April 12, 2011, the PJM Market Implementation Committee (MIC) endorsed the changes recommended by the MMU. The elimination of internal sources and sinks on transmission reservations addressed most of the MMU concerns, as there can no longer be uncollected congestion charges for imports to PJM or exports from PJM. There is still potential exposure to uncollected congestion charges in wheel through transactions, and the MMU will continue to evaluate if additional mitigation measures would be appropriate to address this exposure.

Table 9-54 shows that since the inception of the business rule change on April 12, 2013, there was uncollected congestion in only four months (January 2016, February 2019, January 2026 and March 2026). In those four months, there was negative uncollected congestion. The negative congestion means that market participants who used the not willing to pay congestion transmission option for their wheel through transactions had transactions that flowed in the direction opposite to congestion. When market participants use the not willing to pay congestion product, it also means that they are not willing to receive congestion credits, which was the case in January 2016, February 2019, January 2026 and March 2026.

Table 9-54 Monthly uncollected congestion charges: January 2010 through March 2026

Month	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Jan	$148,764	$3,102	$0	$5	$0	$0	($44)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($3,572)
Feb	$542,575	$1,567	($15)	$249	$0	$0	$0	$0	$0	($69,992)	$0	$0	$0	$0	$0	$0	$0
Mar	$287,417	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($48)
Apr	$31,255	$4,767	($68)	($3,114)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
May	$41,025	$0	($27)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Jun	$169,197	$1,354	$78	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Jul	$827,617	$1,115	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Aug	$731,539	$37	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Sep	$119,162	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Oct	$257,448	($31,443)	($6,870)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Nov	$30,843	($795)	($4,678)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Dec	$127,176	($659)	($209)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Total	$3,314,018	($20,955)	($11,789)	($2,860)	$0	$0	($44)	$0	$0	($69,992)	$0	$0	$0	$0	$0	$0	($3,620)

Transmission Service Requests

Requests for transmission service are made on the PJM Open Access Same Time Information System (OASIS) on any of the posted paths. The products available on the OASIS include both firm and nonfirm service. Nonfirm service is available on an hourly, daily, weekly and monthly basis. Firm transmission service is defined as either short term or long term firm. Short term firm transmission is available on a daily, weekly or monthly basis, and long term firm is available for a period of one year or longer.

The total transfer capability (TTC) reflects the maximum amount of power that can be transferred over a transmission line or a group of transmission lines. In order to maintain reliability, transmission providers do not make the entire TTC available to be used. The available flowgate capability (AFC) is calculated for each path and product pair by taking the TTC and subtracting existing service requests, a capacity benefit margin[65], a transmission reliability margin[66] and taking postbacks and counterflows into consideration. The amount of transmission service that can be reserved is the Available Transfer Capability (ATC). The ATC is calculated for each path and product, and is determined by taking the AFC and adjusting it for all other committed transmission service requests that impact that path.

PJM calculates and posts ATC for all valid posted paths product pairs. The range of calculated ATCs depends on the duration of service. Hourly service is available up to seven days in advance, daily service is available 35 days in advance, weekly service is available five weeks in advance and monthly service is available 18 months in advance. Any transmission request that falls within the posted ATC period is evaluated based on the posted ATC. If there is sufficient capability, the transmission service request is accepted. If there is not sufficient capability, the transmission service request is denied.

Long term firm transmission service requests that extend beyond the ATC posting calculation are subject to system impact studies and must be submitted and evaluated in the new services queue. There is currently a backlog of projects in the new services queue. The backlog is being resolved through a transition to a new planning process, but new transmission service requests may not be evaluated or approved until 2027.[67]

65 The capacity benefit margin is defined by NERC as "the amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs), whose loads are located on that Transmission Service Provider's system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.

66 The transmission reliability margin is defined by NERC as "the amount of TTC necessary to provide reasonable assurance that the interconnected transmission network will be secure".

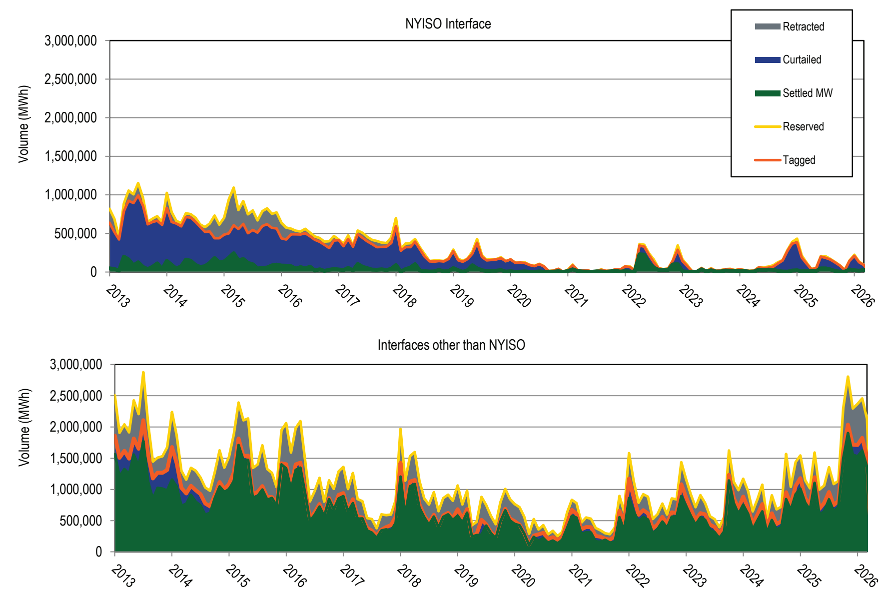
67 See the *2026 Quarterly State of the Market Report for PJM: January through March,* Volume 2, Section 12, "Generation and Transmission Planning," for additional details.

Spot Imports

Figure 9-13 shows the spot import service use for the NYISO Interface, and for all other interfaces, from January 2013 through March 2026. The yellow line shows the total monthly MWh of spot import service reserved and the orange line shows the total monthly MWh of tagged spot import service. The gray shaded area between the yellow and orange lines represents the MWh of retracted spot import service and may represent potential hoarding volumes. This ATC was initially reserved, but not tagged (used). It is possible that in some instances the reserved transmission consisted of the only available ATC which could have been used by another market participant had it not been reserved and not used. The blue shaded area between the orange line and green shaded area represents the MWh of curtailed transactions using spot import service. This area may also represent hoarding opportunities, particularly at the NYISO Interface. In this instance, it is possible that while the market participant reserved and scheduled the transmission, they may have submitted purposely uneconomic bids in the NYISO market so that their transaction would be curtailed, yet their transmission would not be retracted. The NYISO allows for market participants to modify their bids on an hourly basis, so these market participants can hold their transmission service and evaluate their bids hourly, while withholding the transmission from other market participants that may wish to use it. The green shaded area represents the total settled MWh of spot import service. Figure 9-13 shows that while there are proportionally fewer retracted MWh on the NYISO Interface than on all other interfaces, the NYISO has proportionally more curtailed MWh. This is a result of the NYISO market clearing process.[68]

68 See the *2018 Annual State of the Market Report for PJM*, Volume 2, Section 9, "Interchange Transactions," for a more complete discussion of the history of spot import transmission service.

Figure 9-13 Spot import service use: January 2013 through March 2026



The MMU continues to recommend that PJM permit unlimited spot market imports (as well as all nonfirm point to point willing to pay congestion imports and exports) at all PJM interfaces.

Interchange Optimization

When PJM prices are higher than prices in surrounding balancing authorities, imports will flow into PJM until the prices are approximately equal. This is an appropriate market response to price differentials. Given the nature of interface pricing and the treatment of interface transactions, it is not possible for PJM system operators to reliably predict the quantity or sustainability of such imports. The inability to predict interchange volumes creates additional challenges for PJM dispatch in trying to meet loads, especially on high load days. If all external transactions were submitted as real-time dispatchable transactions during emergency conditions, PJM would be able to include interchange transactions in its supply stack, and dispatch only enough interchange to meet the demand.

The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1800 (EPT) on the prior day to three hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes.[69] These changes would give PJM a more flexible product that could be used to meet load based on economic dispatch rather than guessing the sensitivity of the transactions to price changes.

In addition to changing prices, transmission line loading relief procedures (TLRs), market participants' curtailments for economic reasons, and external balancing authority curtailments affect the duration of interchange transactions.

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.

Interchange Cap During Emergency Conditions

An interchange cap is a limit on the level of interchange permitted for nondispatchable energy using spot import or hourly point to point transmission. An interchange cap is a nonmarket intervention which should be a temporary solution and should be replaced with a market based solution as soon as possible. Since the approval of this process on October 30, 2014, PJM has not yet needed to implement an interchange cap.

The purpose of the interchange cap is to help ensure that actual interchange more closely meets operators' expectations of interchange levels when internal PJM resources, e.g. CTs or demand response, are dispatched to meet the peak load. Once these resources have been called on, PJM must honor their minimum operating constraints regardless of whether additional interchange then materializes. Therefore any interchange received in excess of what was expected can have a suppressive effect on energy and reserve pricing and result in increased uplift.

PJM will notify market participants of the possible use of the interchange cap the day before. The interchange cap will be implemented for the forecasted peak and surrounding hours during emergency conditions.

The interchange cap will limit the acceptance of spot import and hourly nonfirm point to point interchange (imports and exports) not submitted as real time with price transactions once net interchange has reached the interchange cap value. Spot imports and hourly nonfirm point to point transactions submitted prior to the implementation of the interchange cap will not be limited. In addition, schedules with firm or network designated transmission service will not be limited either, regardless of whether net interchange is at or above the cap.

The calculation of the interchange cap is based on the operator expectation of interchange at the time the cap is calculated plus an additional margin. The margin is set at 700 MW, which is half of the largest contingency on the system. The additional margin also allows interchange to adjust to the loss of a unit or deviation between actual load and forecasted load. The interchange cap is based on the maximum sustainable interchange from PJM reliability studies.

45 Minute Schedule Duration Rule

PJM limits the change in interchange volumes on 15 minute intervals. These changes are referred to as ramp. The PJM ramp limit is designed to limit the change in the amount of imports or exports in each 15 minute interval to account for the physical characteristics of the generation to respond to changes in the level of imports and exports. The purpose of imposing a ramp limit is to help ensure the reliable operation of the PJM system. The 1,000 MW ramp limit per 15 minute interval was based on the availability of ramping capability by generators in the PJM system. The limit is based

69 The minimum duration for a real-time dispatchable transaction was modified to 15 minutes. See *Integration of Variable Energy Resources*, Order No. 764, 139 FERC ¶ 61,246, *order on reh'g*, Order No. 764-A, 141 FERC ¶ 61231 (2012).

on the assumption that the available generation in the PJM system can only move 1,000 MW over any 15 minute period, although there is no supporting analysis. As an example of how the ramp limit works, if at 0800 (EPT) the sum of all external transactions were -3,000 MW (negative sign indicates net exporting), the limit for 0815 would be -2,000 MW to -4,000 MW. In other words, the starting or ending of transactions would be limited so that the overall change from the previous 15 minute period would not exceed 1,000 MW in either direction.

In 2008, there was an increase in 15 minute external energy transactions that caused swings in imports and exports submitted in response to intrahour LMP changes. This activity was due to market participants' ability to observe price differences between RTOs in the first third of the hour, and predict the direction of the price difference on an hourly integrated basis. Large quantities of MW would then be scheduled between the RTOs for the last 15 minute interval to capture those hourly integrated price differences with relatively little risk of prices changing. This increase in interchange on 15 minute intervals created operational control issues, and in some cases led to an increase in uplift charges due to calling on resources with minimum run times greater than 15 minutes needed to support the interchange transactions. As a result, a new business rule was proposed and approved that required all transactions to be at least 45 minutes in duration.

On June 22, 2012, FERC issued Order No. 764, which required transmission providers to give transmission customers the option to schedule transmission service at 15 minute intervals to reflect more accurate power production forecasts, load and system conditions.[70] On April 17, 2014, FERC issued its order which found that PJM's 45 minute duration rule was inconsistent with Order No. 764.[71]

PJM and the MMU issued a statement indicating ongoing concern about market participants' scheduling behavior, and a commitment to address any scheduling behavior that raises operational or market manipulation concerns.[72]

70 See *id.* at P 51.
71 See *id.* at P 12.
72 See joint statement of PJM and the MMU re Interchange Scheduling issued July 29, 2014 <http://www.monitoringanalytics.com/reports/Market_Messages/Messages/PJM_IMM_Statement_on_Interchange_Scheduling_20140729.pdf>.

MISO Multi-Value Project Usage Rate (MUR)

MISO defines a multi-value project (MVP) to be a project which, according to MISO, enables the reliable and economic delivery of energy in support of public policy needs, provides multiple types of regional economic value or provides a combination of regional reliability and economic value. On July 15, 2010, MISO submitted revisions to the MISO Tariff to implement criteria for identifying and allocating the costs of MVPs.[73] On December 16, 2010, the Commission accepted the proposed MVP charge for export and wheel-through transactions, except for transactions that sink in PJM.[74] The Commission stated that MISO had not shown that their proposal did not constitute a resumption of rate pancaking along the MISO-PJM seam. Following the December 16, 2010, Order, MISO began applying a multi-value usage rate (MUR) to monthly net actual energy withdrawals, export schedules and through schedules with the exception of transactions sinking in PJM. The MUR charge was applied to the relevant transactions in addition to the applicable transmission, ancillary service and network upgrade charges.

On June 7, 2013, the U.S. Court of Appeals for the Seventh Circuit granted a petition for review regarding the Commission's determination in the MVP Order and MVP Rehearing Order.[75] The Court ordered the Commission to consider on remand whether, in light of current conditions, what if any limitations on export pricing to PJM by MISO are justified.[76] The Seventh Circuit highlighted the fact that at the time of the Commission's decision to prohibit rate pancaking on transactions between MISO and PJM, all of MISO's transmission projects were local and provided only local benefits.[77]

On July 13, 2016, FERC issued an order permitting MISO to collect charges associated with MVPs for all transactions sinking in PJM, effective immediately.[78] The July 13th Order noted that in light of "the development of large scale wind generation capable of serving both MISO's and its neighbors' energy policy requirements in the western areas of MISO; the reported need of PJM entities to access those resources; and the reported need for MISO

73 See Midwest Independent Transmission Operator Inc. filing, Docket No. ER10-1791-000 (July 15, 2010).
74 See 133 FERC ¶ 61,221; *order on reh'g*, 137 FERC ¶ 61,074 (2011)
75 Illinois Commerce Commission, et al. v. FERC, 721 F.3d 764, 778–780 (7th Cir. 2013).
76 *Id.* at 780.
77 *Id.* at 779.
78 See 156 FERC ¶ 61,034.

to build new transmission facilities to deliver the output of those resources within MISO for export… it is appropriate to allow MISO to assess the MVP usage charge for transmission service used to export to PJM just as MISO assesses the MVP usage charge for transmission service used to export energy to other regions.”[79]

The policy rationale for permitting MISO to impose transmission costs on PJM market participants without clear criteria is weak and results in pancaking of rates. The impact is expected to increase.

Table 9-55 shows the projected usage rate to be collected for all wheels through and exports from MISO, including those that sink in PJM, for 2024 through 2045.[80] As shown in Table 9-4, there were 2,095.8 GWh of imports from MISO in the first three months of 2026. At the 2026 MUR of $1.58 per MWh, PJM market participants paid $3.3 million towards the costs of MISO’s multi value projects. It is not clear whether the MUR charge has affected interchange volumes from MISO into PJM.

Table 9-55 MISO projected multi value project usage rate: 2026 through 2045

Year	Total Indicative MVP Usage Rate ($/MWh)
2026	$1.58
2027	$1.56
2028	$1.53
2029	$1.50
2030	$1.47
2031	$1.44
2032	$1.41
2033	$1.39
2034	$1.36
2035	$1.33
2036	$1.31
2037	$1.28
2038	$1.26
2039	$1.23
2040	$1.21
2041	$1.18
2042	$1.16
2043	$1.13
2044	$1.11
2045	$1.09

79 *Id.* at P 55.
80 See MISO, “Schedule 26A Indicative Annual Charges,” (March 20, 2025) <https://cdn.misoenergy.org/Schedule%2026A%20Indicative%20Annual%20Charges106365.xlsx>.

10. Ancillary Service Markets

FERC defined six ancillary services in Order No. 888: scheduling, system control and dispatch; reactive supply and voltage control from generation service; regulation and frequency response service; energy imbalance service; operating reserve - spinning reserve service; and operating reserve - supplemental reserve service.[1] PJM provides scheduling, system control and dispatch as part of the PJM administrative function. PJM provides reactive on what is asserted to be a cost of service basis. PJM provides regulation, energy imbalance, synchronized reserve, and supplemental reserve services through market mechanisms.[2] The PJM ancillary service markets are regulation, synchronized reserve, primary reserve, and 30-minute reserve. Although not defined by FERC as an ancillary service, black start service plays a comparable role. Black start service is provided on the basis of formula rates and cost of service rates.

The MMU analyzed measures of market structure, conduct and performance for the PJM Synchronized Reserve Market for the first three months of 2026.

Table 10-1 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 unconcentrated in the real-time market. The MAD Reserve Subzone was highly 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 operating reserve demand curve (ORDC). In an attempt to counter poor unit specific synchronized reserve performance, PJM unilaterally and inappropriately extended the first step of the ORDC for synchronized reserve, known as the synchronized reserve reliability requirement, in May 2023, raising prices for synchronized reserves, nonsynchronized reserves and energy.
- 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.

The MMU analyzed measures of market structure, conduct and performance for the PJM Nonsynchronized Reserve Market for the first three months of 2026.

Table 10-2 The nonsynchronized 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 nonsynchronized reserve market structure was evaluated as not competitive due to supplier concentration for primary reserve. The RTO Reserve Zone was moderately concentrated in the day-ahead market and moderately concentrated in the real-time market. The MAD Reserve Subzone was highly 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.

1 See 75 FERC ¶ 61,080 (1996). PJM renamed spinning reserve as synchronized reserve based on PJM's inclusion of demand side resources in the product.
2 Energy imbalance service refers to the real-time energy market.

- 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 operating reserve demand curve (ORDC). In an attempt to counter poor unit specific synchronized reserve performance, PJM unilaterally and inappropriately extended the first step of the ORDC for synchronized reserve, known as the synchronized reserve reliability requirement, in May 2023. Because the first step of the ORDC for primary reserve, known as the primary reserve reliability requirement, is based on the synchronized reserve reliability requirement, the primary reserve reliability requirement was consequently also extended, raising prices for synchronized reserves, nonsynchronized reserves, and energy.
- Market design was evaluated as flawed based on PJM's modifications to the first step of the ORDC.

The MMU analyzed measures of market structure, conduct and performance for the PJM Secondary Reserve Market for the first three months of 2026.

Table 10-3 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 due to the lack of supplier concentration for 30-minute reserve. The RTO Reserve Zone was unconcentrated in the day-ahead market and unconcentrated in the real-time 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.

The MMU analyzed measures of market structure, conduct and performance for the PJM Regulation Market for the first three months of 2026.

Table 10-4 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 84.5 percent of half hour market intervals in the first three months of 2026.
- Participant behavior in the PJM Regulation Market was evaluated as competitive in the first three months of 2026 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 post-October 1, 2025 market results include an improved approach to opportunity cost but include an incorrect definition of opportunity cost that has significant effects on prices. The definition of performance is also incorrect. The post-October 1, 2025 design is a significant improvement over the pre-October 1, 2025 design although there are significant issues in the new design.

Overview

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. That increase was not justified when implemented as current data demonstrates and the increase should be removed.

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 2026, the real-time average primary reserve requirement was 3,377.5 MW in the RTO Reserve Zone and 2,701.5 MW in the Mid-Atlantic Dominion Reserve Subzone. In the first three months of 2026, the day-ahead average primary reserve requirement was 3,380.6 MW in the RTO Reserve Zone and 2,695.2 MW in the Mid-Atlantic Dominion Reserve Subzone.
- **Market Concentration.** The Mid-Atlantic Dominion (MAD) Reserve Subzone Market for primary reserve was characterized by structural market power in the first three months of 2026. The average HHI for real-time primary reserve in the RTO Reserve Zone was 1149, which is classified as moderately concentrated. The real-time RTO primary reserve market was highly concentrated in 1.3 percent of intervals.[3] The average HHI for day-ahead primary reserve in the RTO Zone was 1126, which is classified as moderately concentrated. The day-ahead RTO primary reserve market was highly concentrated in 1.8 percent of hours. The average HHI for real-time primary reserve in the MAD Reserve Subzone was 2554, which is classified as highly concentrated. The real-time MAD primary reserve market was highly concentrated in 80.6 percent of intervals. The average HHI for day-ahead primary reserve in the MAD Reserve Subzone was 2198, which is classified as highly concentrated. The day-ahead time MAD primary reserve market was highly concentrated in 65.6 percent of hours.

Synchronized Reserve Market

Synchronized reserves include all capacity synchronized to the grid and available to provide power 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.

3 FERC defines a highly concentrated market as having an HHI greater than 1800.

Market Structure

- **Supply.** In the first three months of 2026, the real-time average supply of available synchronized reserve was 5,453.7 MW in the RTO Reserve Zone, of which 2,384.9 MW on average was located in the Mid-Atlantic Dominion Reserve Subzone. In the first three months of 2026, the day-ahead average supply of available synchronized reserve was 6,693.7 MW in the RTO Reserve Zone, of which 3,077.3 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 2026 was 2,315.0 MW in the RTO Reserve Zone and 1,864.4 MW in the Mid-Atlantic Dominion Reserve Subzone. The day-ahead average synchronized reserve requirement in the first three months of 2026 was 2,317.1 MW in the RTO Reserve Zone and 1,860.2 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 2026. The average HHI for real-time synchronized reserve in the RTO Reserve Zone was 901, which is classified as unconcentrated. The real-time RTO synchronized reserve market was highly concentrated in 0.1 percent of intervals. The average HHI for day-ahead synchronized reserve in the RTO Zone was 922, which is classified as unconcentrated. The day-ahead RTO synchronized reserve market was highly concentrated in 0.6 percent of hours. The average HHI for real-time synchronized reserve in the MAD Reserve Subzone was 1989, which is classified as highly concentrated. The real-time MAD synchronized reserve market was highly concentrated in 55.6 percent of intervals. The average HHI for day-ahead synchronized reserve in the MAD Reserve Subzone was 1800, which is classified as highly concentrated. The day-ahead MAD synchronized reserve market was highly concentrated in 42.6 percent of hours.

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 Resource model participants, 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.

  In December 2024, PJM updated the economic basepoint signal to include deployed reserve MW during synchronized reserve events, improving performance. The yearly average performance in 2024 for events that were 10 minutes or longer was 58.2 percent, while for 2025 it was 78.3 percent and for 2026 it was 72.3 percent. However, significant communications technology and modelling issues when calling resources during spinning events continue to result in slow response from a significant share of resources.

Market Performance

- **Price.** In the first three months of 2026, for the Mid-Atlantic Dominion Reserve Subzone, the weighted average real-time price for synchronized reserve was $6.23 per MWh and the weighted average day-ahead price was $8.11 per MWh. In the first three months of 2026, for the RTO Reserve Zone, the weighted average real-time price for synchronized reserve was

$6.38 per MWh and the weighted average day-ahead price was $7.50 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 2026, the real-time average supply of eligible and available nonsynchronized reserve was 1,173.8 MW in the RTO Reserve Zone, of which 783.2 MW on average was available in the Mid-Atlantic Dominion Reserve Subzone. In the first three months of 2026, the real-time average supply of eligible and available nonsynchronized reserve was 1,193.2 MW in the RTO Reserve Zone, of which 739.5 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.[4] 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 reserve due to secondary reserve having 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.[5] Hybrid units and Energy Storage Resource model participants 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 2026, the nonsynchronized reserve weighted average real-time price for all intervals in the RTO Reserve Zone was $2.34 per MWh and the weighted average day-ahead price was $1.96 per MWh. In the first three months of 2026, the nonsynchronized reserve weighted average real-time price for all intervals in the MAD Reserve Subzone was $2.94 per MWh and the weighted average day-ahead price was $1.48 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. By default, there is no reserve subzone for 30-minute 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 2026, the real-time average supply of available 30-minute reserve was 26,301.7 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

4 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.1 Overview of the PJM Reserve Markets, Rev. 136 (Oct. 1, 2025).

5 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.3 Reserve Market Resource Offer Structure, Rev. 136 (Oct. 1, 2025).

increased the synchronized reserve reliability requirement, the 30-minute reserve reliability requirement is frequently equal to the primary reserve reliability requirement. In the first three months of 2026, the average 30-minute reserve requirement was 3,453.2 MW in the real-time market and 3,452.3 MW in the day-ahead market.

- **Market Concentration.** The RTO Reserve Zone Market for 30-minute reserves was characterized by low concentration in the first three months of 2026. In the first three months of 2026, the average HHI for real-time 30-minute reserves was 748, which is classified as unconcentrated. The real-time RTO 30-minute reserve market was highly concentrated in 0.1 percent of intervals. In the first three months of 2026, the average HHI for day-ahead 30-minute reserves was 841, which is classified as unconcentrated. The day-ahead RTO 30-minute reserve market was highly concentrated in 0.0 percent of hours.

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 2026, in the RTO Reserve Zone, the real-time average supply of available secondary reserve was 20,180.6 MW and the day-ahead average supply of available secondary reserve was 12,307.3 MW. 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.[6]

Market Conduct

- **Offers.** Energy Storage Resource model participants, 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.[7] 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 2026, the secondary reserve real-time price for all intervals was $0.00 per MWh. In the first three months of 2026, the secondary reserve day-ahead price for all hours was $0.00 per MWh.

Regulation Market

The PJM Regulation Market is a real-time market. The regulation market design changed significantly on October 1, 2025. 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.

PJM plans to implement additional changes to the regulation market in a second phase, to be implemented on October 1, 2026. This phase 2 will include separate regulation up and regulation down markets. The Phase 1 changes eliminated many of the significant issues identified by the MMU under the pre-October 1, 2025, design. However, the Phase 1 changes introduced new issues that are significantly affecting market prices.

This report analyzes the results of the regulation market in the first three months of 2026.

6 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.1 Overview of the PJM Reserve Markets, Rev. 136 (Oct. 1, 2025).

7 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.3 Reserve Market Resource Offer Structure, Rev. 136 (Oct. 1, 2025).

Market Structure

- **Supply.** In the first three months of 2026, the average half hour offered supply of regulation for nonramp hours was 958.8 actual MW (835.4 effective MW), 1,117.2 actual MW (967.8 effective MW) for shoulder hours, and 1,200.8 actual MW (1,048.1 effective MW) for ramp hours.
- **Demand.** The half hour regulation demand is 550 MW for nonramp hours, 650 MW for shoulder hours, and 750 MW for ramp hours.
- **Supply and Demand.** The nonramp regulation requirement of 550.0 effective MW was provided by 623.1 hourly average actual MW in the first three months of 2026. The shoulder regulation requirement of 650.0 effective MW was provided by 740.2 hourly average actual MW in the first three months of 2026. The ramp regulation requirement of 750.0 effective MW was provided by 848.9 hourly average actual MW in the first three months of 2026.

  The ratio of the average half hour offered supply of regulation to average half hour regulation demand (actual cleared MW) for nonramp hours was 1.54 in the first three months of 2026. The ratio of the average half hour offered supply of regulation to average half hour regulation demand (actual cleared MW) for shoulder hours was 1.15 in the first three months of 2026. The ratio of the average half hour offered supply of regulation to average half hour regulation demand (actual cleared MW) for ramp hours was 1.41 in the first three months of 2026.
- **Market Concentration.** In the first three months of 2026, the three pivotal supplier test was failed in 84.5 percent of half hours. In the first three months of 2026, the effective MW weighted average HHI was 1268, 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. In the first three months of 2026, there were 217 resources providing regulation.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $148.22 per MW of regulation in first three months of 2026. The weighted average cost of regulation in the first three months of 2026 was $151.56 per MW of regulation.

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).[8]

In the first three months of 2026, total black start charges were $11.4 million, a decrease of $4.8 million (29.4 percent) from the first three months of 2025. In the first three months of 2026, total revenue requirement charges were $11.2 million, a decrease of $4.7 million (29.6 percent) from the first three months of 2025. In the first three months of 2026, total black start uplift charges were $0.2 million, a decrease of $0.04 million (14.9 percent) from 2025. 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 2026 ranged from $0 in the OVEC and REC Zones to $2.2 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.[9] By order issued September 23, 2025, the

8 OATT Schedule 1 § 1.3BB. There are no ALR units currently providing black start service.
9 See 182 FERC ¶ 61,194.

Commission approved a settlement over the MMU's objection that continued to allow overcompensation.[10] On July 4, 2025, enactment of the One Big Beautiful Bill Act (OBBBA) changed the rules for bonus depreciation again, allowing 100 percent bonus depreciation for assets constructed between January 20, 2025 and December 31, 2028, and placed in service before January 1, 2031.[11] The CRF values for affected units should incorporate 100 percent bonus depreciation. It is essential that PJM not repeat its earlier mistake when it ignored the tax law changes in 2017.

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.[12] RTOs and their customers are not required to separately compensate generation resources for such reactive capability.[13]

In the first three months of 2026, PJM customers paid $85.6 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 and the order approving PJM's compliance filing.[14]

10 See 193 FERC ¶ 61,059
11 OBBA § 70301(b)(3).
12 OATT Attachment O.
13 See 182 FERC ¶ 61,033 at P 52 (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).
14 See *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); 192 FERC ¶ 61,113 (2025).

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.

In the first three months of 2026, total reactive charges were $85.7 million, a decrease of $6.5 million (7.1 percent) from first three months of 2025. In the first three months of 2026, total reactive capability charges were $85.6 million, a decrease of $6.1 million (6.7 percent) from the first three months of 2025. In the first three months of 2026, total reactive service charges were $0.1 million, a decrease of $0.4 million (77.1 percent) from the first three months of 2025.

Total zonal reactive service charges ranged from $0 in the REC and OVEC Zones, to $13.8 million in the AEP Zone in the first three months of 2026.

Primary Frequency Response

On February 15, 2018, the Commission issued Order No. 842, which modified the pro forma large and small generator interconnection agreements and procedures to require all newly interconnecting non-nuclear generating facilities, both synchronous and nonsynchronous, to include equipment for primary frequency response capability as a condition to receive interconnection service.[15] [16]

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 $\pm$0.036 Hz deadband.[17] 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.

15 Nuclear Regulatory Commission (NRC) regulated facilities are exempt from this provision. Behind the meter generation that is sized to load is also exempt.
16 Frequency bias settings and frequency response obligations are shared in NERC's Resources Subcommittee <https://www.nerc.com/comm/OC/Pages/Resources-Subcommittee.aspx> and PJM's Operating Committee <https://www.pjm.com/committees-and-groups/committees/oc.aspx>.
17 OATT Attachment O § 4.7.2 (Primary Frequency Response).

The response of generators within PJM to NERC identified frequency events occurs two to three times per month. A frequency event is declared whenever the system frequency stays outside ±0.040 Hz deadband for at least one minute, and the minimum/maximum frequency reaches ±0.053 Hz.[18] 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. From June 2024 through May 2025, the NERC BAL-003-2 requirement for balancing authorities (PJM is a balancing authority) used a threshold value (L_{10}) equal to ±258.3 MW/0.1 Hz.[19] Effective June 2025 through May 2026, the threshold value (L_{10}) is equal to ±227.6 MW/0.1 Hz.[20]

The MMU has identified several issues with PJM's enforcement and evaluation of generation PFR performance.

Market Procurement of Real-Time Ancillary Services

PJM uses market mechanisms to varying degrees in the procurement of ancillary services including synchronized reserves, primary reserves, 30-minute 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 resource parameters and offers.

All reserve products are jointly cleared with energy in every real-time market solution. The synchronized reserve market clearing is more integrated with the energy market clearing than the other ancillary services because dispatched energy and synchronized reserve are outputs of the same optimization problem for each market interval. 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.[21] Instead, inflexible synchronized reserves are cleared hourly by the Ancillary Service Optimizer (ASO) or the day-ahead energy market.[22] 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 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.

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 automatically respond to the notifications. (Priority: Medium. First reported 2023. Status: Partially adopted 2024.)

18 See PJM. "PJM Manual 12: Balancing Operations," § 3.6.2 Event Selection, Rev. 56 (Oct. 1, 2025).
19 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>.
20 See NERC. "2025 Frequency Bias Settings," Sep. 9, 2025. <https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/rs/oy_2025_frequency_bias_annual_calculations.pdf>.
21 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.4.3 Reserve Market Clearing, Rev. 136 (Oct. 1, 2025).
22 Starting October 1, 2025, the ASO now schedules regulation in half-hour blocks. However, as before the change, the ASO still schedules reserves in one-hour blocks.

- 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 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 increase to the synchronized reserve reliability requirement that PJM added based on a misunderstanding of reserve performance during synchronized reserve events. (Priority: High. First reported 2024. Status: Not adopted.)
- The MMU recommends that reserve resources operating below economic minimum should not be treated as being backed down by that amount to provide reserve. (Priority: Medium. First reported 2025. 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: Adopted 2025.)[23]
- 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: Adopted 2025.)[24]
- 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: Adopted 2025.)[25]
- The MMU recommends that the calculation of the performance score (based on precision, delay and correlation metrics) be replaced. (Priority: Medium. First reported 2023. Status: Partially adopted.).
- The MMU recommends that the performance score be revised to eliminate the effect of the size of the regulation assignment and to directly calculate the performance score based on the actual performance and the requested performance. (Priority: High. First reported 2025. Status: Not adopted.).
- The MMU recommends that the regulation market optimization be reviewed to address the logic that allows the partial clearing of inframarginal resources. (Priority: Medium. First reported 2025. Status: Not adopted.).
- The MMU recommends that if a unit sets its economic maximum at a value greater than its regulation maximum, the lost opportunity cost (LOC) of the unit should be calculated assuming the economic maximum of the unit is equal to the regulation maximum of the unit. The MMU

23 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, was implemented on October 1, 2025, resulting in a single signal, bidirectional market with one clearing price that eliminates the need for an MBF. Phase 1 eliminated RegA and RegD dual offers. Phase 1 reduced 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 is based on the resource's dispatched energy offer schedule, not the lower of its price or cost offer schedule.
24 See *id.*
25 See 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).

recommends that, in cases where offered ramp is greater than actual ramp, the actual ramp be used to calculate the LOC of the unit. The MMU recommends that these fixes to the LOC logic be implemented prior to implementing Phase 2 of the regulation market design. (Priority: High. New Recommendation. Status: Not adopted.).

- 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: Adopted 2025.).[26]
- The MMU recommends that the lost opportunity cost in all of 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: Adopted 2025.[27] FERC rejected.)[28]
- 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: Adopted 2025. FERC accepted.)[29]
- 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: Adopted 2025.)[30]
- The MMU recommends enhanced documentation of the implementation of the regulation market design. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected.)[31]
- 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.)[32]

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. First reported Q1, 2025. Status: Not adopted.)
- The MMU recommends that PJM develop the metric(s) necessary to objectively evaluate each unit's performance during primary frequency

26 See *id.*
27 This recommendation was adopted by PJM for the energy market and the regulation market. Lost opportunity costs in the energy market and the regulation market are calculated using the schedule on which the unit is scheduled to run.
28 See 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).
29 See *id.*
30 In Phase 1 the ramp rate limited desired MW output is used in the regulation uplift calculation. The MMU does not agree with how this change has been implemented.
31 See *id.*
32 See *id.*

response events. (Priority: Medium. First reported Q2, 2025. 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. First reported Q1, 2025. Status: Not adopted.)
- 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: Adopted 2024.)[33]
- 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. CRF rates effective January 20, 2025, should reflect 100 percent bonus depreciation.[34] (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends that black start planning and coordination be on a regional basis recognizing cross zonal cranking paths and not on a narrowly or purely 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.)
- The MMU recommends that the black start rate under the Base Formula Rate should be based on the actual cost of providing the black start service, plus an incentive, rather than the unsupported use of Net CONE, escalated each year. (Priority: Medium. First reported 2025. Status: Not adopted.)
- The MMU recommends that the fuel assurance rules be modified to recognize actual fuel assured resources within and across zones. (Priority: High. First reported Q2, 2025. Status: Not adopted.)
- The MMU recommends that the Reliability Backstop for black start service be eliminated. There is no reason that PJM cannot acquire black start resources if the TOs can acquire black start resources. (Priority: High. First reported Q2, 2025. Status: Not adopted.)

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. 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 once during Winter Storm Elliott and once during the July 2025 hot weather event, 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 in reserve requirements were the primary cause of higher reserve prices in 2023, 2024, 2025, and the first three months of 2026, including 35 intervals of shortage pricing in May 2023 and several intervals of shortage pricing during spin events in 2024, 2025, and the first three months of 2026, 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

33 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. This recommendation will be implemented effective June 1, 2026.

34 OBBA § 70301(b)(3).

should be on correcting issues related to the responses of individual units rather than increasing demand.

Significant communications technology and modelling issues when calling resources during spinning events result in slow response. While PJM now calculates reserve offer MW for the majority of resource types, a resource's cleared reserve MW are based on a resource's energy output at the end of a scheduling interval. If a unit is still moving when an event is called, such as near the beginning of a scheduling interval, it may or may not be able to achieve its scheduled output. Likewise, a unit that is decreasing output to create more headroom might not be able to immediately increase output when an event is called.

Although PJM now augments a resource's economic basepoint with its dispatched reserve MW during a spin event, PJM does not require resources to be able to receive this signal. Many resources are still dispatched using phone calls, either from markets operation centers waiting for the PJM ALL-CALL or from MOCs themselves manually calling plant personnel.

Even if a unit is on AGC and receiving the augmented basepoint, depending on where that unit finds itself on its ramp rate curve, it might have to spend time coming off AGC or decreasing output in order to start ramping using power augmentation. Having a synchronized reserve maximum that is less than the unit's economic maximum can address this case, but it is the unit's responsibility to request the exception.

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 and by requiring the actual use of the signal. The archaic telephone communications technology has been a source of slow response times, such as markets operation centers waiting for the PJM ALL-CALL or manually calling unit personnel to deploy reserves. 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 automatically 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 nor that the receiving units be able to follow the signal for deploying reserves. Further improvements in communications technology and requirements 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 and DSR 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 improved communications technology, 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 increase to the synchronized reserve reliability requirement in place from May 2023 through March 2026.

PJM will implement significant changes to the regulation market in two phases.[35] Phase 1, implemented on October 1, 2025, is a single product, single signal market with one clearing price. Phase 2, to be implemented on October 1, 2026, will include separate regulation up and regulation down markets. The Phase 1 changes eliminated 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. The actual implementation of the new design is flawed, but the design is significantly improved. Significant new issues were created by Phase 1 that significantly affect price and should be fixed as soon as possible.

The benefits of markets can be realized under the current approach to ancillary service markets. Even in the presence of structurally noncompetitive markets,

35 See 187 FERC ¶ 61,173.

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 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 not competitive. The MMU concludes that the secondary reserve market results were competitive. The MMU concludes that the regulation market results were not competitive, and that the pre-October 1, 2025, market design is significantly flawed.

PJM Reserve Markets

Reserves resources are scheduled and paid for the availability to respond to a loss of supply on the system by increasing their energy output within defined time limits. When a resource clears in a reserve market, it is assigned scheduled reserve MW by that reserve market. Most reserve MW are cleared by the reserve markets, but PJM has the ability to schedule resources outside of the markets when needed.

PJM clears reserves to satisfy defined reserve service requirements. There are three reserve services: the synchronized reserve service (SR), the primary reserve service (PR), and the 30-minute reserve service (TMR). Each reserve service is defined by its response time requirement and by whether the service can be provided by offline resources (Table10-5). Only the synchronized reserve service requires that all providers be online and synchronized to the grid. The other two services, primary reserve and 30-minute reserve, can be provided by both online and offline resources.

Table 10-5 Reserve services and their definitions

Service	Response Requirement (minutes)	Provided by Online Resources	Provided by Offline Resources
Synchronized Reserve	10 or less	Yes	No
Primary Reserve	10 or less	Yes	Yes
30-Minute Reserve	30 or less	Yes	Yes

Each reserve service requires a specified number of MW to be available in order to cover a potential loss of supply event, known as that service's reserve requirement. The size of a service's requirement depends on the contingencies that the service is designed to address (determining the service's reliability requirement), plus the option to add a requirement to account for potential demand increases due to temporary conditions like emergencies and weather alerts (determining the extended requirement). A service's total requirement is equal to the sum of its reliability requirement, which is unique to each service, plus the extended reserve requirement, which is the same for all services and has a base value of 190 MW.[36] [37] The default extended reserve requirement of 190 MW was designed to phase in the price impacts of shortage pricing in real time.

The reserve services are nested, such that the satisfaction of the synchronized reserve requirement counts towards the satisfaction of the primary reserve requirement, which counts towards the satisfaction of the 30-minute reserve requirement. The principal contingency for which reserves are cleared is the loss, in a single event, of the largest generator or group of generators, known as the "most severe single contingency," or the MSSC. Therefore, the reliability requirement of each service, in whole or in part, depends upon the size of the MSSC. Table10-6 shows the default definitions of the reliability requirements and the full requirements. For calculating the 30-minute reserve requirement, PJM uses a pre-defined set of additional contingencies to simulate the effects of gas infrastructure failures on gas generators.[38] The use of these special

36 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.3 Reserve Requirement Determination, Rev. 136 (Oct. 1, 2025).
37 PJM has proposed creating individual extended requirements for each reserve service. This proposal was approved by the Reserve Certainty Senior Task Force on June 6, 2024, but was rejected by the Markets & Reliability Committee on July 24, 2024.
38 See PJM. "PJM Manual 13: Emergency Operations," § 3.9 Assessing Gas Infrastructure Contingency Impacts on the Electric System, Rev. 97 (Nov. 20, 2025).

contingencies is communicated to generators via PJM Emergency Procedures under "Gas Pipeline Emergencies".[39]

PJM selectively calls upon reserve services to respond to events. For example, to engage synchronized reserves, PJM initiates a synchronized reserve event, also called a spinning event.[40] In the first three months of 2026, PJM did not call on nonsynchronized reserves to collectively respond to a reserve event. PJM calls on some nonsynchronized resources to individually respond during synchronized reserve events.

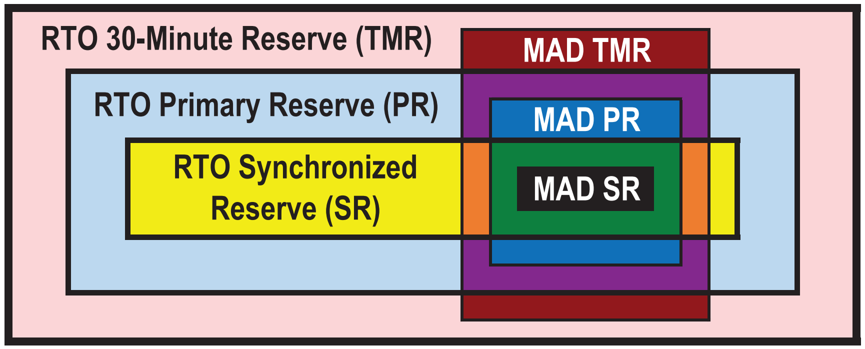
The deployment of 10-minute reserves can also be in response to dispatches from the New York Independent System Operator (NYISO), which serves as the dispatcher for shared reserve activation.[41] [42] Members of the PJM Mid-Atlantic Control Zone have agreed to activate a portion of 10-minute reserve in coordination with members of the Northeast Power Coordinating Council when directed in order to relieve stress on the interconnected grid.

During an event, reserves respond either by increasing their energy output to the grid or by decreasing their energy consumption from the grid. The delivery of this energy is constrained by transmission limits, such that there are also limited locational requirements for each of the reserve services, except for the 30-minute reserve service.[43] PJM uses these constraints to define a reserve subzone with its own smaller requirements for synchronized reserve and primary reserve. Reserves in the subzone count towards the satisfaction of the requirements for the entire RTO Reserve Zone.[44] For example, satisfaction of the synchronized reserve requirement in the Mid-Atlantic Dominion (MAD) Reserve Subzone also counts towards the primary reserve requirement in the MAD Subzone and the synchronized reserve requirement in the RTO Zone, which in turn counts towards the satisfaction of the primary reserve requirement in the RTO Zone. There is only one active reserve subzone at a time. Figure 10-1 shows how reserve requirements for the MAD Reserve Subzone are nested inside the RTO Reserve Zone when the MAD Subzone is the active subzone.

Table 10-6 Service requirement definitions[45]

Service	Service Reliability Requirement	Service Extended Requirement
Synchronized Reserve (SR)	Most Severe Single Contingency	SR Reliability Requirement + Extended Reserve Requirement
Primary Reserve (PR)	1.5 × SR Reliability Requirement	PR Reliability Requirement + Extended Reserve Requirement
30-Minute Reserve (TMR)	Max(Largest Active Gas Contingency, PR Reliability Requirement, 3,000 MW)	TMR Reliability Requirement + Extended Reserve Requirement

Figure 10-1 Service nesting in the RTO Reserve Zone and the Mid-Atlantic Dominion (MAD) Reserve Subzone



In May 2023, PJM made two unilateral changes in succession to the reserve requirements to compensate for the asserted lack of performance during spin events. Table 10-21 shows the average performance for events 10 or more minutes long. The average response to the two events of 10 minutes or more that occurred in the first four months of 2023, both in January, was 56.9 percent, compared to 50.3 percent in the last three months of 2022. On May 12, 2023, PJM inappropriately increased the extended reserve requirement by 1,588 MW and on May 15, 2023, PJM reversed the increase. On

39 PJM. Emergency Procedures – Message Definitions. (2025) <https://emergencyprocedures.pjm.com/ep/pages/messagedefinitions.jsf> Mar. 3, 2025.
40 See PJM. "PJM Manual 12: Balancing Operations," § 4.1.2 Loading Reserves, Rev. 56 (Oct. 1, 2025).
41 See PJM. "PJM Manual 12: Balancing Operations," § 4.2 Shared Reserves, Rev. 56 (Oct. 1, 2025).
42 See NPCC. "NPCC Regional Reliability Directory #5: Reserve," Attachment B - Simultaneous Activation of Ten-Minute Reserve (SAR) Contingencies, Rev. 5 (Apr. 20, 2020).
43 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.3.1 Locational Aspect of Reserves, Rev. 136 (Oct. 1, 2025).
44 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.4.1 Product and Locational Substitution, Rev. 136 (Oct. 1, 2025).
45 From mid-May 2023 through December 2025, PJM has set the synchronized reserve reliability requirement to be 130 percent of the MSSC. See "Synchronized Reserve Requirement for Reliability – Update," (March 6, 2025). <https://www.pjm.com/-/media/DotCom/committees-groups/committees/oc/2025/20250306/20250306-item-08b---synchronized-reserve-adder.pdf>.

May 19, 2023, PJM inappropriately increased the synchronized reserve reliability requirement by 30 percentage points to 130 percent of the MSSC. The reliability requirement was 130 percent of the MSSC in 2025. Figure 10-18 compares the changes in demand. PJM will decrease or increase the adder based on the average performance across non-overlapping sets of three 10-minute events.[46]

The reserve requirements effective for a scheduling interval can change from interval to interval depending on the contingencies and needs of the grid. When maintenance work at a power station risks tripping multiple generators whose total output is larger than the MSSC, PJM can increase the requirement for synchronized reserve to include that total output. PJM can increase the reserve requirement due to emergencies and weather alerts. In May 2023, PJM unilaterally modified *PJM Manual 11: Energy & Ancillary Services Market Operations* to allow PJM to temporarily increase the requirements to compensate for poor resource performance in order to continue compliance with ReliabilityFirst's regional criteria.[47] [48] Table 10-7 shows the instances identified by the MMU when PJM temporarily increased the reserve requirements in the first three months of 2026.

Table 10-7 Temporary adjustments to 30-minute, primary, and synchronized reserve requirements: January through March, 2026[49]

From	To	Number of Hours	Amount of Adjustment
19-May-2023	08-Jan-2026	23,208	30 percent increase to synchronized reserve reliability requirement
09-Jan-2026	Ongoing	1,968+	20 percent increase to synchronized reserve reliability requirement
09-Mar-2026	30-Mar-2026	511	30-Minute Reserve (28 MW), Primary Reserve (28 MW), Synchronized Reserve (19 MW)

PJM must comply with the reserve requirements imposed by NERC, but PJM uses requirements that are more restrictive than NERC requirements. NERC Performance Standard BAL-002-3, which describes NERC's Disturbance Control Standard (DCS), defines a requirement for contingency reserve, which PJM implements as primary reserve.[50] [51] NERC BAL-002-3 does not define requirements specifically for synchronized reserve or for 30-minute reserve. NERC requires that contingency reserves respond within 15 minutes, while PJM requires that primary reserves respond within 10 minutes. NERC requires that PJM have contingency reserves greater than or equal to the MSSC, while PJM has historically targeted procuring primary reserve equal to at least 150 percent of the MSSC and procuring synchronized reserve equal to at least 100 percent of the MSSC. With PJM's increase to the synchronized reserve reliability requirement (Table10-7), from May 19, 2023, until January 9, 2026, PJM targeted procuring primary reserve in excess of 195 percent of the MSSC and procuring synchronized reserve in excess of 130 percent of the MSSC. From January 9, 2026, through March 31, 2026, and continuing, PJM targeted procuring primary reserve in excess of 180 percent of the MSSC and procuring synchronized reserve in excess of 120 percent of the MSSC.

A NERC DCS event is defined as the loss of supply, in a single event, of 80 percent or more of the MSSC. The event begins as soon as the Reporting ACE (a version of the area control error) starts to drop and ends when the Reporting ACE returns to the lesser of zero and its value at the start of the event. Although PJM uses synchronized reserve events to recover from DCS events, synchronized reserve events are generally longer than their corresponding DCS events (Figure 10-20).

46 See "Synchronized Reserve Requirement for Reliability – Update," PJM presentation to the Operating Committee. (March 6, 2025) <https://www.pjm.com/-/media/DotCom/committees-groups/committees/oc/2025/20250306/20250306-item-08b---synchronized-reserve-adder.pdf>.
47 RFC_Criteria_BAL-002-02. "Operating Reserves," August 29, 2012. <https://rfirst.org/ProgramAreas/Standards/Criteria/Regional%20Criteria%20Library/RFC_Criteria_BAL-002-02.pdf>.
48 See *id*, which describes the document as a "ReliabilityFirst Board of Directors approved good utility practice document which are not reliability standards" and notes that "ReliabilityFirst Regional Criteria are not NERC reliability standards, regional reliability standards, or regional variances, and therefore are not enforceable under authority delegated by NERC pursuant to delegation agreements and do not require NERC approval."
49 PJM does not make public the exact increases in reserves nor the exact times increases are used. This table shows the differences between the average reserve values during times that have been identified for possible increases in reserves with the average values before and after those times. The ranges given can include several overlapping timespans of possible increases.
50 NERC BAL-002-3. "Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event," April 1, 2019. <https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-002-3.pdf>.
51 See PJM. "PJM Manual 10: Pre-Scheduling Operations," § 3.1.1 Day-ahead and Real-Time Reserves, Rev. 46 (Jul. 23, 2025).

There are three kinds of resources that can provide reserves: online generators that can increase their energy output, offline generators that can start and provide their energy output, and demand response resources that can decrease their energy use. From these resources, there are three reserve products: synchronized reserves (SR), nonsynchronized reserves (NSR), and secondary reserves (SecR).[52] A reserve product is defined by its response-time requirement and by the types of resources that can provide it (Table 10-8).

Table 10-8 Reserve products and definitions

Reserve Product	Response Requirement (minutes)	Provided by Online Generators	Provided by Offline Generators	Provided by Demand-Side Response
Synchronized Reserve	10 or less	Yes	No	Yes
Nonsynchronized Reserve	10 or less	No	Yes	No
Secondary Reserve	10 exclusive to 30 exclusive	Yes	Yes	Yes

A reserve product can only be used to satisfy a reserve service's scheduling requirement if it also satisfies that service's response-time requirement and synchronization requirement, which are listed in Table 10-5. Table 10-9 shows which reserve products can be used to satisfy which reserve services.

Table 10-9 Reserve products and the services they can provide

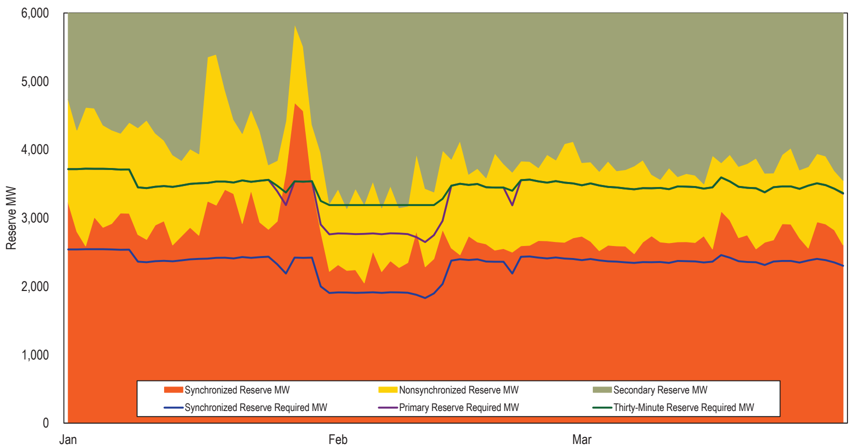
Reserve Product	Can Provide Synchronized Reserve	Can Provide Primary Reserve	Can Provide 30-Minute Reserve
Synchronized Reserve	Yes	Yes	Yes
Nonsynchronized Reserve	No	Yes	Yes
Secondary Reserve	No	No	Yes

Figure 10-2 shows how reserve products were cleared in real time to meet the reserve service requirements in the first three months of 2026. In the figure, each line represents the extended requirement of a reserve service, which is the service's reliability requirement plus the generic extended requirement. The colored areas represent how the cleared MW of the three reserve products combine to satisfy the reserve requirements. As can be seen in the figure, the cleared reserve products providing the services do not exactly equal the service requirements. In the first three months of 2026, the total amounts of cleared synchronized reserve and 30-minute reserve were frequently greater than their requirements. This can result from cleared resources providing more reserves than needed to satisfy the remainder of a requirement and can result from PJM clearing reserve products to help satisfy the requirements of the next broader reserve service. For example, in January, PJM cleared synchronized reserves in excess of the synchronized reserve requirement in order to, along with the cleared nonsynchronized reserve, more economically satisfy the primary reserve requirement.

Although not seen in Figure 10-2, PJM does not always clear enough reserves to satisfy a reserve requirement. When a service's requirement is not met, the result is shortage pricing.

52 OATT, Attachment K - Appendix § 1.7.19 (Ramping).

Figure 10-2 Daily average real-time reserve products cleared and daily average real-time reserve service requirements used by RT SCED: January through March, 2026



PJM uses market mechanisms to clear resources. In general, products that meet shorter response time requirements and that can be used to satisfy multiple reserve requirements have higher prices. The objective is to minimize total cost when purchasing reserves and energy.

Implementation of PJM Reserve Markets

While the primary reserve requirement and 30-minute reserve requirement can be satisfied using multiple products, the products are purchased separately. There are separate markets for synchronized reserves, nonsynchronized reserves, and secondary reserves.[53] MW that are selected as reserve are said to have cleared the market. Effective October 1, 2022, each product's reserve market has a day-ahead component and a real-time component. The obligations of a reserve resource depend on its real-time assignment, which in turn depends on how the resource clears the day-ahead and real-time markets. A resource that cleared one market is not guaranteed to have cleared the other market, and a resource that cleared both markets need not clear the same amount in real time as it did day ahead. Although multiple reserve products can be used to satisfy the same reserve service requirements, the reserve products are not necessarily paid the same market clearing prices. Each market for a reserve product has a single market clearing price that is applied to all reserve MW cleared in that market, regardless of the service that required the clearing of those MW.

In general, the reserve MW available from a resource are calculated by PJM based on the parameters in the resource's energy offer and reserve parameters. Some resource types, such as hydroelectric resources, Energy Storage Resource model participants, and demand response resources, can specify reserve offer amounts.[54] Generation capacity resources are required to participate in the reserve markets. However, nuclear, solar, and wind resources are excluded by default and must request inclusion in the reserve markets. PJM can automatically deselect a resource from participating in the reserve market for performance reasons.[55] [56] PJM can temporarily deselect a resource from providing reserves for, among other reasons, failing to reliably follow PJM's dispatch signal. A resource that is deselected for failing to follow PJM's dispatch signal is in violation of its must-offer requirement.[57]

A generation resource can request a maximum MW value for its reserve offer (synchronized, secondary, or both individually) that is lower than its economic maximum if that generator's reserve offer is subject to a physical limitation that cannot be modeled by a segmented hourly ramp rate.[58] Such a request must include documentation and data demonstrating the limitation. Both PJM and the MMU review the request. PJM must respond within 30 days after data supporting the request is submitted, telling the generation owner whether the request was accepted or denied, and if denied, for what reason.

53 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.4.1 Product and Locational Substitution, Rev. 136 (Oct. 1, 2025).

54 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.3 Reserve Market Resource Offer Structure, Rev. 136 (Oct. 1, 2025).

55 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Reserve Market Eligibility, Rev. 136 (Oct. 1, 2025).

56 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.4.3.1 Deselection of Reserve Resources in Real-Time, Rev. 136 (Oct. 1, 2025).

57 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.4.3.1 Deselection of Reserve Resources in Real-Time, Rev. 136 (Oct. 1, 2025).

58 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.2.1 Communication for Reserve Capability Limitation, Rev. 136 (Oct. 1, 2025).

The clearing of resources to meet PJM's operational requirements includes multiple steps to commit resources, dispatch resources, and calculate clearing prices.[59 60] Each program in the commitment and dispatching process estimates future needs. The day-ahead market solution software schedules resources in one-hour blocks.[61] The real-time software schedules resources in five-minute intervals.

Due to their start and notification times, some resources can only be cleared in the earlier steps of PJM's commitment and dispatching process. Depending on their physical run-time requirements, resources are described as either flexible or inflexible. Inflexible resources are those that must run for at least one hour and are only committed in real-time by the hour-ahead real-time software or by a PJM operator, and can include demand response resources, offline CTs and hydro resources that can operate in condensing mode, and resources whose economic minimum output equals their economic maximum output. Flexible resources are those that can be cleared for reserves by RT SCED later in the process. Such resources are already online for energy, require no notification time, and can be automatically dispatched.

In general, resources do not have to clear the same amounts in the real-time and day-ahead markets, and a resource that cleared one of the markets is not guaranteed to have cleared the other. However, if an inflexible condenser or an inflexible economic load response resource has a day-ahead assignment, that assignment is also applied to the operating day.[62]

Not all resources that provide reserves necessarily clear the reserve market. When needed, PJM is able to manually schedule a resource for reserves if that resource would not have otherwise run.[63] Similarly, not all inflexible reserve resources cleared by the ASO and IT SCED are necessarily used for reserves. When needed, PJM can manually switch inflexible resources from providing reserves to providing energy.

Figure 10-4 compares the daily average requirements of the day-ahead clearing engine, the ASO, and RT SCED. Figure 10-4 shows that the reserve requirements used by the ASO and RT SCED do not differ significantly. Until May 12, 2023, the daily average 30-minute reserve requirement was almost always 3,190 MW in the day-ahead software, the ASO, and RT SCED (Figure 10-4).

Figure 10-3 compares the daily average cleared MW of the day-ahead clearing engine, the ASO, and RT SCED. In addition to the increase in cleared secondary reserve resulting from PJM correcting its software error, Figure 10-3 shows that the day-ahead market also tended to clear the most nonsynchronized reserve. For satisfying the primary reserve requirement, the ASO uses more synchronized reserves, clearing less nonsynchronized reserves than RT SCED due to differences in the available MW that result from differences in the applied unit schedules. This difference is also seen in Figure 10-25.

59 For more on the market solution software, see the *2019 Annual State of the Market Report for PJM*, Appendix E - Ancillary Service Markets.
60 For more on the market solution software, see the *2019 Annual State of the Market Report for PJM*, Appendix E - Ancillary Service Markets.
61 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.4.2 Day-ahead Reserve Market Clearing, Rev. 136 (Oct. 1, 2025).
62 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.4.3 Real-time Reserve Market Clearing, Rev. 136 (Oct. 1, 2025).
63 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.4.3 Real-time Reserve Market Clearing, Rev. 136 (Oct. 1, 2025).

Figure 10-3 Daily average MW cleared by the day-ahead engine, the ASO, and RT SCED: January through March, 2026

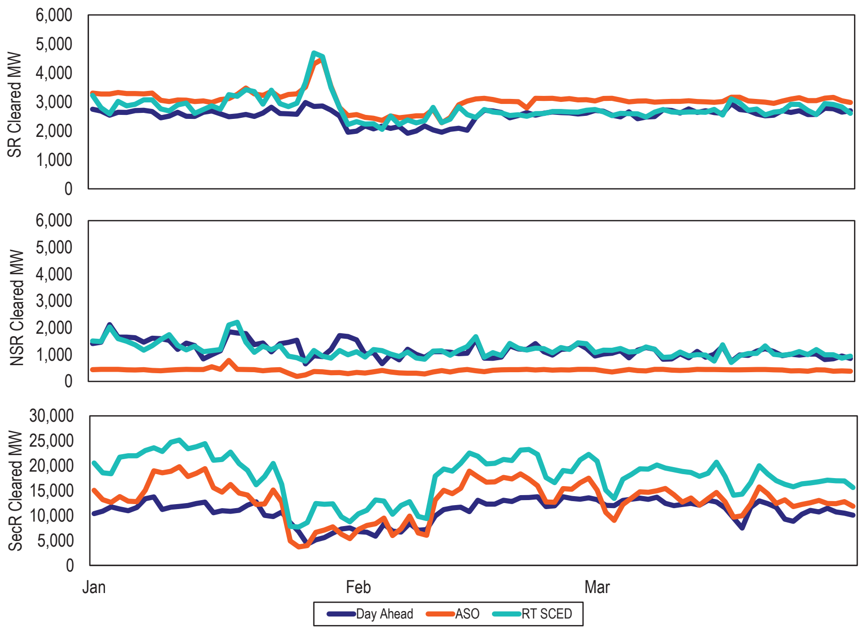


Figure 10-4 Daily average requirements used in the day-ahead engine, the ASO, and RT SCED: January through March, 2026

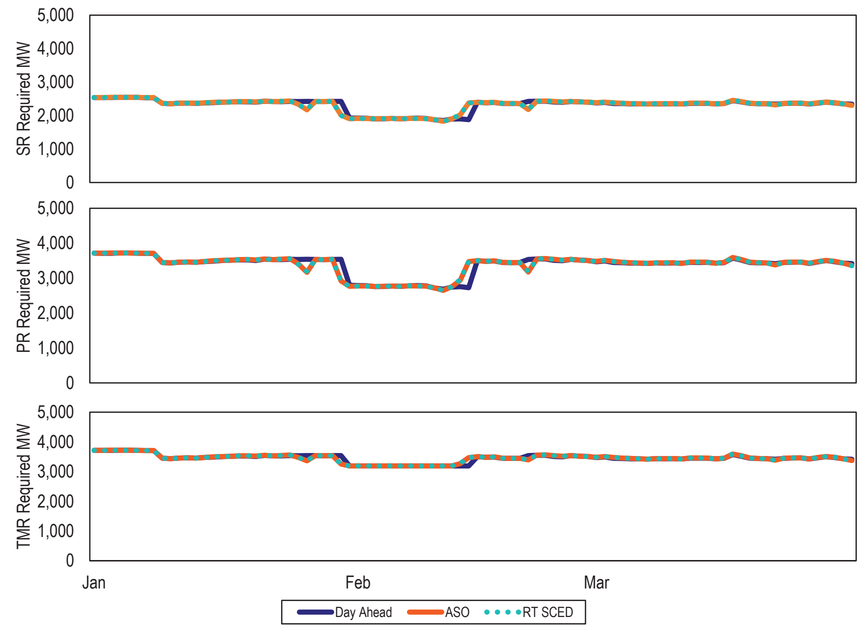
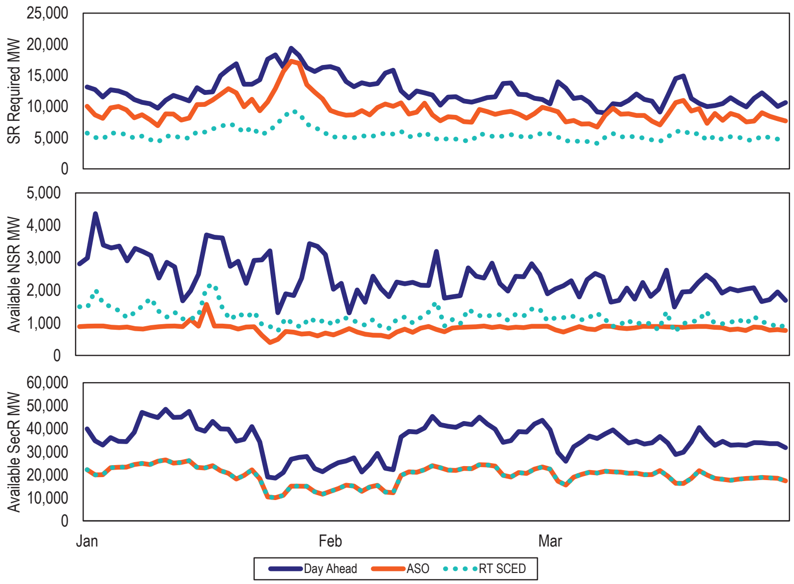


Figure 10-5 Daily average available MW used in the day-ahead engine, the ASO, and RT SCED: January through March, 2026

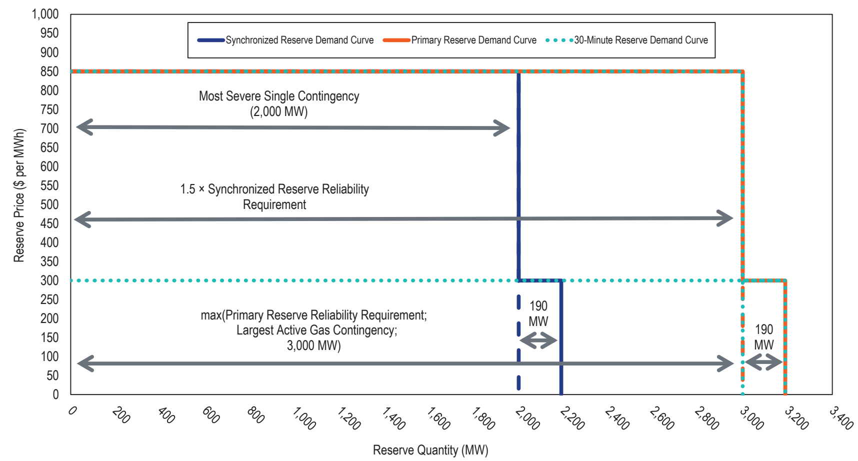


There is a defined MW demand only for synchronized reserves, primary reserves, and 30-minute reserves. The demand for nonsynchronized reserves and for secondary reserves is derived from those defined MW demand levels and cleared supply. PJM's administratively defined demand curve for reserves is called the Operating Reserve Demand Curve (ORDC) and has two steps. The first step of each reserve product's ORDC is set at that product's reliability requirement and is priced at $850 per MWh. The second step is the extended reserve requirement and is priced at $300 per MWh. Figure 10-6 shows example ORDCs for the three reserve products using an example MSSC of 1,000 MW with no increases in the extended reserve requirement.

In 2014, PJM added an optional second step to the ORDC, which could be increased from its default value of 0 MW to account for increased uncertainty identified by PJM. In 2017, PJM proposed a minimum value of 190 MW for the then optional second step, bringing it to its current form.[64] [65]

Figure 10-6 shows an example of the three operating reserve demand curves for each reserve product for an example MSSC at 1,000 MW with no increases in the extended reserve requirement. The adjusted ORDCs resulting from PJM's increase to the synchronized reserve reliability requirement are shown in Figure 10-19.

Figure 10-6 An example of the reserve product real-time operating reserve demand curves, including the permanent second steps



During periods of shortage pricing, the reserve market clearing prices can be higher than the limits shown in Figure 10-6. Offer prices for synchronized reserve are cost based and are capped at the expected value of the synchronized reserve penalty. The product substitution cost is a function of LMPs, the marginal cost of energy for the resources providing reserves, and the minimized cost of substituted MW providing energy. At the margin, the

64 See the transmittal letter to Revisions to OA Schedule 1 and OATT Att K-Appx RE Operating Reserve Demand Curve, Docket No. ER17-1590-000 (May 12, 2017) at 8.

65 For background data, see "Shortage Pricing ORDC - Order 825," PJM presentation to the Market Implementation Committee. (October 26, 2016) <https://www.pjm.com/-/media/committees-groups/committees/mic/20161026-special/20161026-item-03-shortage-ordc.ashx>.

price is the sum of the offer price and the product substitution cost of the marginal unit(s).[66]

Like the markets, credits and charges for reserves have day-ahead and real-time components. Day-ahead credits depend only on a resource's day-ahead assignment and the day-ahead market clearing price. There are no lost opportunity cost (LOC) credits in the day-ahead market, nor are there any shortfall charges applied to day-ahead assignments when evaluating resource performance. These concepts apply only to the real-time reserve markets.

The real-time component, known as the balancing credit, is added to day-ahead credits based on the difference between the real-time and day-ahead assignments. This balancing credit for a resource is the sum of a resource's balancing MCP credit and LOC credit, less any shortfall charge for failing to provide the service. If a resource clears less MW in real-time than in the day-ahead market, and if it is found to be at fault for this reduction, then the balancing MCP credit is negative and so the resource buys back this difference at real-time prices. If the resource clears more in real time, then it is positive. If a resource's real-time assignment is the same as its day-ahead assignment, then the balancing MCP credit is $0 and the resource's total MCP credit uses only the day-ahead MCP.

For the synchronized reserve product and the secondary reserve product, the MW for which a resource receives real-time credit can be capped at a value less than the cleared real-time amount. Without capping, a reserve resource producing energy above its directed amount would be paid for reserve MW that it did not actually make available.

Reserve Subzones

Reserve subzones address transmission limits that may prevent the lowest cost reserves from being deliverable throughout the RTO. A reserve subzone has its own reserve requirements, which can only be satisfied by resources within the subzone. The RTO Reserve Zone has only one active subzone at any time. In practice, PJM has maintained only one subzone, the Mid-Atlantic Dominion Reserve Subzone (MAD), and in every market solution, the most limiting constraining path sets the transfer limit between the RTO and in MAD. The price in MAD may exceed the price in the rest of the RTO when the constraints are binding.

While PJM generally triggers synchronized reserve events for the entire RTO, PJM has the option to only deploy reserves in the defined subzone. For example, on January 18, 2026, PJM triggered a synchronized reserve event only for MAD.

The choice of MAD was a result of historical congestion patterns. Transmission limits at times required maintaining out of merit reserves in the MAD area. On most days, the MAD Subzone is no longer binding. As of October 1, 2022, PJM has a process to revise the definition of the subzone. The subzone definition may change as often as daily based on system conditions, and new subzones can be defined as needed.[67] To date, PJM has used only the MAD Reserve Subzone as the chosen subzone.

Figure 10-7 is a map of constraints and major generation sources, showing how the constraints separating the RTO Reserve Zone and MAD Reserve Subzone are defined by the underlying grid topology. The most frequently binding constraints in the first three months of 2026 were Brighton-Conastone, Bedington-Black Oak, and Black Oak-Hatfield.

Figure 10-8 shows the reserve service requirements and cleared reserve product in the MAD Reserve Subzone in the first three months of 2026. As there is no 30-minute reserve requirement for the MAD Reserve Subzone, secondary reserve is excluded. The increase in reserve requirements in effect since mid-May 2023 does not apply to the MAD Reserve Subzone, only to the RTO Reserve Zone.

66 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.9 Synchronized Reserve Market Clearing Price (SRMCP) Calculation, Rev. 121 (July 7, 2022). This version of the manual has a clearer definition than later versions.

67 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.3.2 Creation of New Reserve Subzones, Rev. 136 (Oct. 1, 2025).

Figure 10-7 PJM RTO Zone and MAD Subzone map of constraints and generation sources

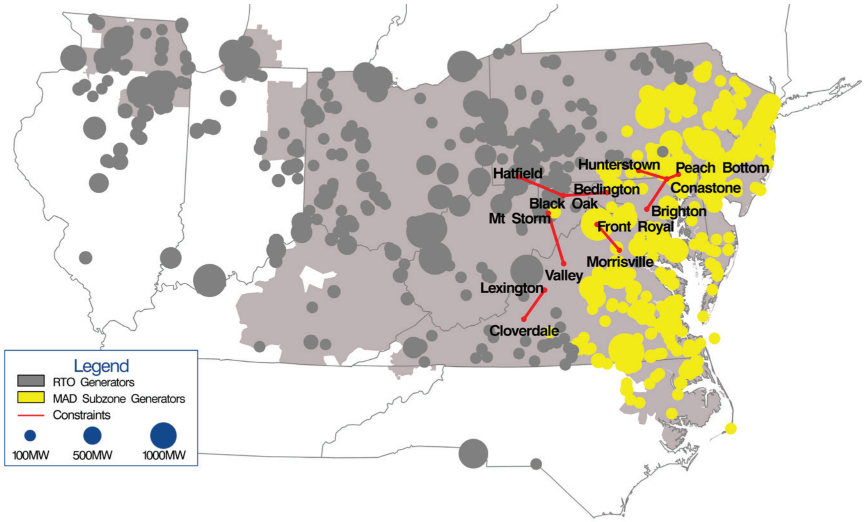
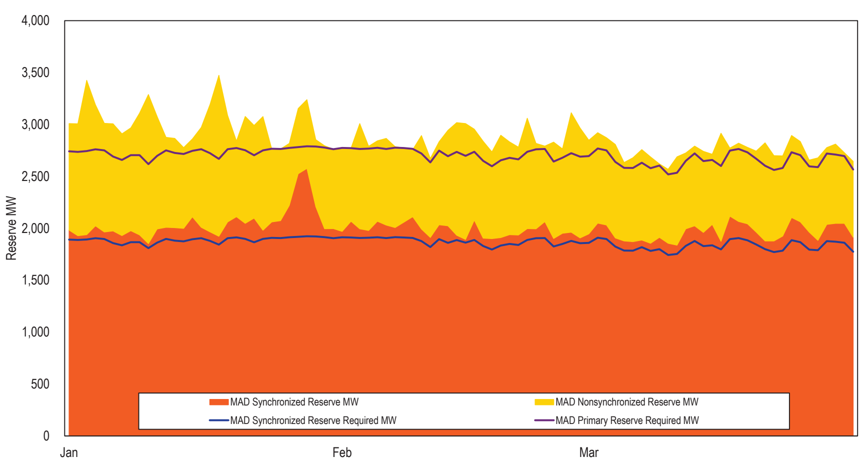


Figure 10-8 Daily average real-time MAD reserve products and daily average real-time MAD reserve service requirements: January through March, 2026



Primary Reserve

NERC Performance Standard BAL-002-3, Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event, requires PJM to carry sufficient contingency reserve to recover from a sudden balancing contingency (usually a loss of generation). The Contingency Event Recovery Period is the time required to return the Reporting ACE to the lesser of zero and its pre-event level. The Contingency Reserve Restoration period is the time required to restore contingency (primary) reserve to a level greater than or equal to the largest single contingency after the end of the Contingency Event Recovery Period. NERC standards set the Contingency Event Recovery Period as 15 minutes and the Contingency Reserve Restoration Period as 90 minutes.[68] The NERC requirement is 100 percent compliance and status must be reported quarterly. PJM implements this contingency reserve recovery period requirement using primary reserve.[69] PJM maintains 10-minute reserve (primary reserve) which is more conservative than the NERC requirement. PJM's primary reserve is made up of resources, both synchronized and nonsynchronized, that can provide energy within 10 minutes. PJM does not have a Contingency Reserve Restoration Period standard.

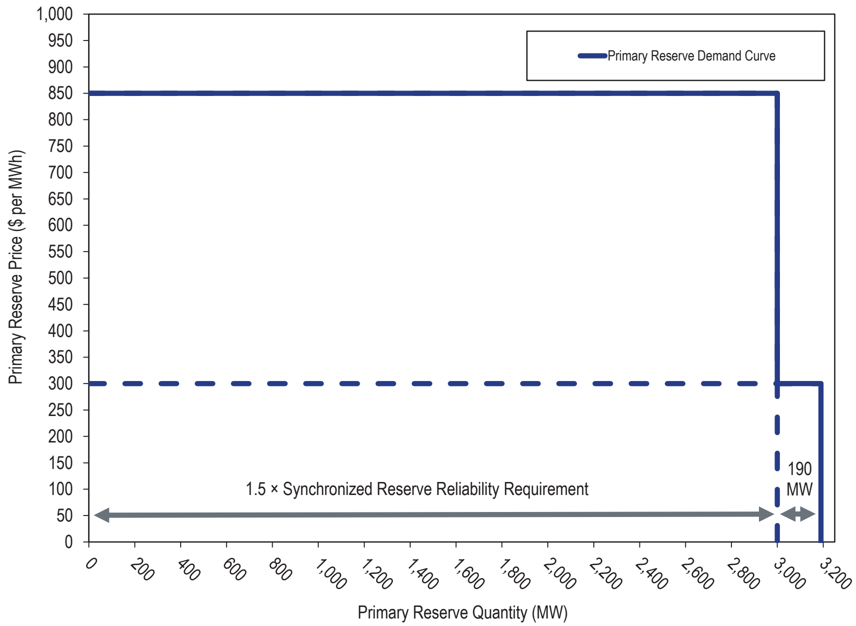
Market Structure

Demand

Demand for primary reserves is based on the primary reserve requirement. The primary reserve requirement is equal to the sum of the primary reserve reliability requirement, unique to the primary reserve service, plus the extended reserve requirement, which is the same for all services. The primary reserve reliability requirement is equal to 150 percent of the synchronized reserve reliability requirement. Figure 10-9 shows an example operating reserve demand curve for primary reserve for an example synchronized reserve reliability requirement of 2,000 MW plus the default 190 MW extension.

68 See PJM. "PJM Manual 12: Balancing Operations," Rev. 56 (Oct. 1, 2025) Attachment D, "the Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance. Subsequently, PJM must fully restore the Synchronized Reserve within 90 minutes." While this cited attachment only references restoring synchronized reserves, PJM Manuals 10 & 13 make it clear that primary reserves serve as PJM's contingency reserves, although PJM generally uses synchronized reserves to recover from contingency events.
69 See PJM. "PJM Manual 10: Pre-Scheduling Operations," § 3.1 Reserve Definitions, Rev. 46 (Jul. 23, 2025).

Figure 10-9 An example of a primary reserve real-time operating reserve demand curve, including the permanent second step



In the first three months of 2026, the average primary reserve requirement for the RTO Zone was 3,377.5 MW in the real-time market and 3,380.6 MW in the day-ahead market. The average primary reserve requirement in the MAD Subzone was 2,701.5 MW in the real-time market and 2,695.2 MW in the day-ahead market.

In an attempt to offset poor unit specific synchronized reserve performance, PJM unilaterally and inappropriately made changes to the reserve requirements in May 2023. On May 12, 2023, PJM inappropriately increased the extended reserve requirement by 1,588 MW and on May 15, 2023, PJM reversed the increase. On May 19, 2023, PJM inappropriately increased the synchronized reserve reliability requirement by 30 percentage points to 130 percent of the MSSC. In effect, this increased the primary reserve reliability requirement by 45 percentage points to 195 percent of the MSSC. PJM has announced criteria to decrease or increase the adder based on average performance across non-overlapping sets of three 10-minute events.[70]

Supply

In the first three months of 2026, the demand for primary reserve was satisfied by synchronized reserves and nonsynchronized reserves. The primary reserve requirement is met from the least expensive combination of synchronized and nonsynchronized reserves that satisfies the requirements of the primary reserve service and the synchronized reserve service. Table 10-10 shows the real-time average available MW from synchronized and nonsynchronized resources in the first three months of 2026.

Table 10-10 Average available MW for clearing: January through March, 2026

Location	Synchronized Reserve MW	Nonsynchronized Reserve MW
RTO	5,453.7	1,173.8
MAD	2,384.9	783.2

Table 10-11 provides the average dispatched reserves, by reserve product, used by the RT SCED market solution to satisfy the primary reserve requirement in the MAD Subzone from January 2025 through March 2026. Table 10-12 shows the average dispatched reserves, by reserve product, used by the RT SCED market solution to satisfy the primary reserve requirement in the RTO Zone from January 2025 through March 2026.

70 See "Synchronized Reserve Requirement for Reliability – Update," PJM presentation to the Operating Committee. (March 6, 2025) <https://www.pjm.com/-/media/DotCom/committees-groups/committees/oc/2025/20250306/20250306-item-08b---synchronized-reserve-adder.pdf>.

Table 10-11 Average monthly reserves used to satisfy the primary reserve requirement, MAD Subzone: January 2025 through March 2026

Year	Month	Synchronized Reserve MW	Nonsynchronized Reserve MW	Total Primary Reserve MW
2025	Jan	1,984.6	924.8	2,909.4
2025	Feb	1,970.7	839.5	2,810.2
2025	Mar	1,966.3	666.9	2,633.2
2025	Apr	1,783.1	598.5	2,381.6
2025	May	1,832.7	618.7	2,451.4
2025	Jun	2,040.1	613.2	2,653.3
2025	Jul	2,038.1	621.3	2,659.4
2025	Aug	2,072.8	738.4	2,811.2
2025	Sep	2,089.3	770.6	2,859.9
2025	Oct	1,929.8	690.6	2,620.4
2025	Nov	1,972.0	714.1	2,686.1
2025	Dec	2,008.6	863.0	2,871.7
2025	Average	1,970.2	755.9	2,726.1
2026	Jan	2,047.6	960.4	3,008.1
2026	Feb	1,982.7	879.2	2,862.0
2026	Mar	1,962.9	790.2	2,753.2
2026	Average	1,998.3	876.6	2,874.9

Table 10-12 Average monthly reserves used to satisfy the primary reserve requirement, RTO Zone: January 2025 through March 2026

Year	Month	Synchronized Reserve MW	Nonsynchronized Reserve MW	Total Primary Reserve MW
2025	Jan	2,581.5	1,130.2	3,711.8
2025	Feb	2,111.2	1,012.8	3,124.0
2025	Mar	2,801.9	881.5	3,683.4
2025	Apr	2,182.8	776.3	2,959.1
2025	May	2,894.5	863.9	3,758.3
2025	Jun	3,222.9	734.0	3,956.8
2025	Jul	3,580.8	746.6	4,327.4
2025	Aug	4,068.4	1,096.1	5,164.6
2025	Sep	3,814.6	980.6	4,795.2
2025	Oct	2,952.2	789.0	3,741.2
2025	Nov	3,130.1	971.4	4,101.6
2025	Dec	3,066.4	1,298.3	4,364.7
2025	Average	3,041.0	940.3	3,981.3
2026	Jan	3,081.1	1,322.1	4,403.2
2026	Feb	2,502.5	1,146.8	3,649.3
2026	Mar	2,705.6	1,048.6	3,754.1
2026	Average	2,771.8	1,173.4	3,945.2

Market Concentration

In the first three months of 2026, the RTO primary reserve market was moderately concentrated in day ahead and moderately concentrated in real time. In the first three months of 2026, the MAD primary reserve market was highly concentrated in day ahead and highly concentrated in real time. Table 10-13 shows the average of the HHI values of each interval for primary reserves in the first three months of 2026.

Table 10-13 Average primary reserve HHI: January through March, 2026

Location	Market	Average HHI	Percent of Intervals Max Market Share Above 20%	Description
RTO	RT	1149	72.0%	Moderately Concentrated
RTO	DA	1126	64.8%	Moderately Concentrated
MAD	RT	2554	99.0%	Highly Concentrated
MAD	DA	2198	97.5%	Highly Concentrated

Market Performance

Figure 10-10 shows daily weighted average synchronized and nonsynchronized market clearing prices in the first three months of 2026. The synchronized reserve market clearing prices for the RTO Reserve Zone and the MAD Reserve Subzone diverged in 62 intervals, 0.2 percent of the total 25,908 five-minute intervals in the first three months of 2026.[71] The nonsynchronized reserve market clearing prices for the RTO Reserve Zone and the MAD Reserve Subzone diverged in 59 intervals, 0.2 percent of the total 25,908 five-minute intervals in the first three months of 2026.

Prices of synchronized reserve and nonsynchronized reserve spiked in late January and early February during a cold weather event that included Winter Storm Fern. Shortage pricing was used for RTO primary reserve on January 24 and 31; February 2, 6, 9, 13, and 16; and March 1, 12, 13, and 22. Shortage pricing was used for MAD primary reserve on January 24; February 9; and March 1, 12, and 13. Shortage pricing was used for RTO synchronized reserve on January 23 and 30; February 1, 4, 6, and 7; and March 1, 13, and 14. Shortage pricing was used for MAD synchronized reserve on January 23 and on March 12 and 13. For the cold weather event, conservative operations were declared from January 24 through February 2.

Table 10-14 shows the number of intervals with shortage pricing in which the amount cleared by RT SCED was greater than the reserve requirement absent the increase to the synchronized reserve reliability requirement. In the first three months of 2026, in the majority of intervals with shortage pricing, RT SCED cleared enough reserve MW to satisfy the original RTO reserve service requirements. These intervals were not short in the sense of failing to clear a sufficient amount of reserves; these intervals were short because of PJM's unilateral increase to the synchronized reserve reliability requirement. The unilateral increase does not affect the MAD Reserve Subzone.

Figure 10-10 Daily average market clearing prices for synchronized reserve and nonsynchronized reserve: January through March, 2026

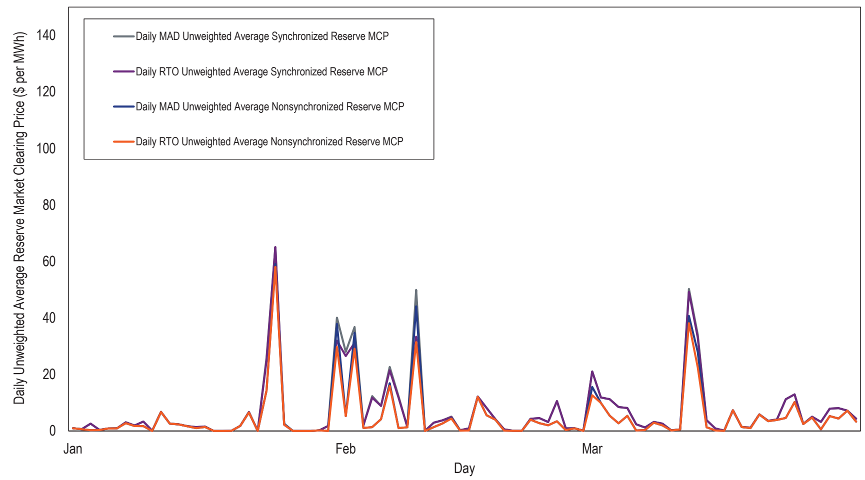


Table 10-14 Number of shortage pricing intervals which satisfied the unmodified reserve service requirement: January through March, 2026

	Reserve Service		
	SR	PR	TMR
Intervals with Shortage Pricing	22	76	0
Intervals where RT SCED Satisfied Original Requirement	22	58	0
Percentage of Intervals where RT SCED Satisfied Original Requirement	100.0%	76.3%	NA
Intervals where RT SCED Did Not Satisfy Original Requirement	0	18	0

71 Billing data can be modified by PJM Settlements at any time to reflect changes in the evaluation of energy uplift. The billing data reflected in this report were current on April 6, 2026.

Synchronized Reserve

All eligible generation capacity resources capable of providing synchronized reserves have a must offer requirement, and all cleared synchronized reserves have an obligation to perform and receive payment based on the synchronized reserve market clearing price. PJM Manual 11 states, "Any generator that is a PJM generation capacity resource that has a Reliability Pricing Model (RPM) or Fixed Resource Requirement (FRR) Resource commitment that is eligible to provide Reserves must offer their 10-minute and 30-minute reserve capability, unless the unit is unavailable due to an approved planned outage, maintenance outage or forced outage."[72]

Since October 1, 2022, the reserve market design for synchronized reserve includes both day-ahead and real-time markets. Prior to that date, synchronized reserve was only a real-time product.

PJM uses synchronized reserve when PJM calls synchronized reserve events, also called spin events or spinning events.

Market Structure

For most resources, synchronized reserves consist of any online capacity not being used for energy that can be achieved within 10 minutes from the current dispatch point according to the resource's ramp rate. The PJM market solves an economic dispatch to determine which, if any, of these resources should be backed down to provide reserves. Some nondispatchable resources can provide synchronized reserves, including storage resources, hydro resources with storage, synchronous condensers, and demand response resources. For both the RTO and the reserve subzone, the day-ahead market clears hourly synchronized reserve assignments and the real-time market clears five-minute synchronized reserve assignments.

Demand

Demand for the synchronized reserve product comes from the reserve requirement for the synchronized reserve service. The synchronized reserve requirement is equal to the synchronized reserve reliability requirement plus the extended reserve requirement. The synchronized reserve reliability requirement is normally equal to the most severe single contingency (MSSC). Figure 10-6 shows an example operating reserve demand curve for synchronized reserve.

In the first four months of 2023, the synchronized reserve reliability requirement was equal to the most severe single contingency (MSSC). PJM unilaterally increased the extended reserve requirement by 1,588 MW from May 12, 2023, through May 15, 2023. Then, on May 19, 2023, PJM unilaterally increased the synchronized reserve reliability requirement to 130 percent of the MSSC, which increased the effective primary reserve reliability requirement from 150 percent of the MSSC to 195 percent of the MSSC. From May 19, 2023, through January 8, 2026, the demand portion was equal to 130 percent of the MSSC. From January 9, 2026, through March 2026, the demand portion has been equal to 120 percent of the MSSC. This increase does not apply to the MAD requirement and does not apply to the RTO requirement when the RTO MSSC is inside of the MAD Reserve Subzone. Figure 10-18 compares the old and new RTO ORDCs with an example MSSC of 1,000 MW.

Figure 10-2 shows a plot of the RTO daily average real-time requirement for synchronized reserve and the RTO daily average cleared synchronized reserve MW. Figure 10-11 shows the real-time and day-ahead daily average synchronized reserve requirements for the RTO Reserve Zone and the MAD Reserve Subzone. In the first three months of 2026, the average real-time synchronized requirement in the RTO Reserve Zone was 2,315.0 MW and the average day-ahead requirement was 2,317.1 MW. In the MAD Reserve Subzone, the average real-time synchronized requirement was 1,864.4 MW and the average day-ahead requirement was 1,860.2 MW. In February 2026, the RTO and MAD requirements were frequently equal because the MSSC in the MAD Reserve Subzone during those intervals was also the MSSC of the whole RTO Reserve Zone. PJM's SR adder does not apply to MSSCs inside of the MAD Reserve Subzone.

72 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.2 Reserve Resource Offer Requirements, Rev. 136 (Oct. 1, 2025).

Figure 10-11 Daily average required MW: January through March, 2026

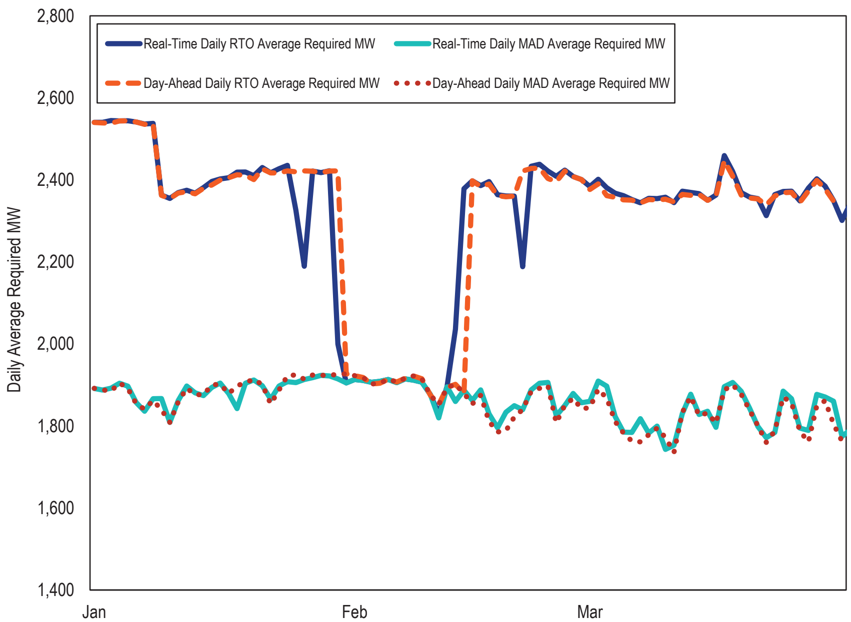


Figure 10-17 compares the total amount of cleared synchronized reserve with the subset of cleared synchronized reserve that is provided by DSR. Prior to October 1, 2022, DSR resources were limited by PJM to being no more than 33 percent of the total cleared synchronized reserves in each interval, but that limitation was removed on October 1, 2022, as part of the Reserve Price Formation changes to the reserve markets.

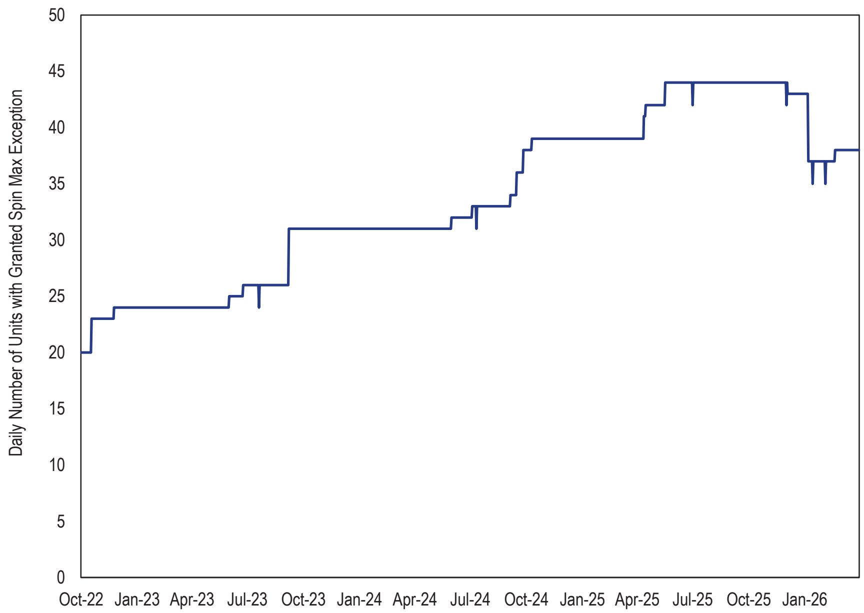
Supply

The supply of synchronized reserves consists of all unloaded capacity from eligible online generators that can convert to energy in 10 minutes and offers from eligible economic load response that can curtail in 10 minutes.[73] Any of this capacity that is not offered as dispatchable in the energy market does not have a lost opportunity cost in the security constrained economic dispatch (SCED). This includes synchronous condensers, storage resources, and demand response. Synchronous condensers and demand response are also considered inflexible in the reserve market and require an hourly commitment, which is made by the Ancillary Services Optimizer (ASO) in real time.[74] This means that these resources enter the SCED reserves supply curve with a marginal cost of zero because PJM is effectively committing them as must run, block loaded reserves.

In general, a resource's reserve MW are the lesser of a resource's 10-minute ramp, and the difference between its energy output and its economic maximum output. A generation resource can request a maximum MW value for its synchronized reserve offer that is lower than its economic maximum if that generator's reserve offer is subject to a physical limitation that cannot be modeled by a segmented hourly ramp rate.[75] For example, units that must hold their output steady while activating duct burners. Figure 10-12 shows how the number of units that can use a lower synchronized reserve maximum MW has increased. If generators in need of the exception request it, PJM should see improved reserve performance due to a more accurate calculation of the available reserve MW.

73 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Reserve Market Eligibility, Rev. 136 (Oct. 1, 2025).
74 Starting October 1, 2025, the ASO now schedules regulation in half-hour blocks. However, as before the change, the ASO still schedules reserves in one-hour blocks.
75 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.2.1 Communication for Reserve Capability Limitation, Rev. 136 (Oct. 1, 2025).

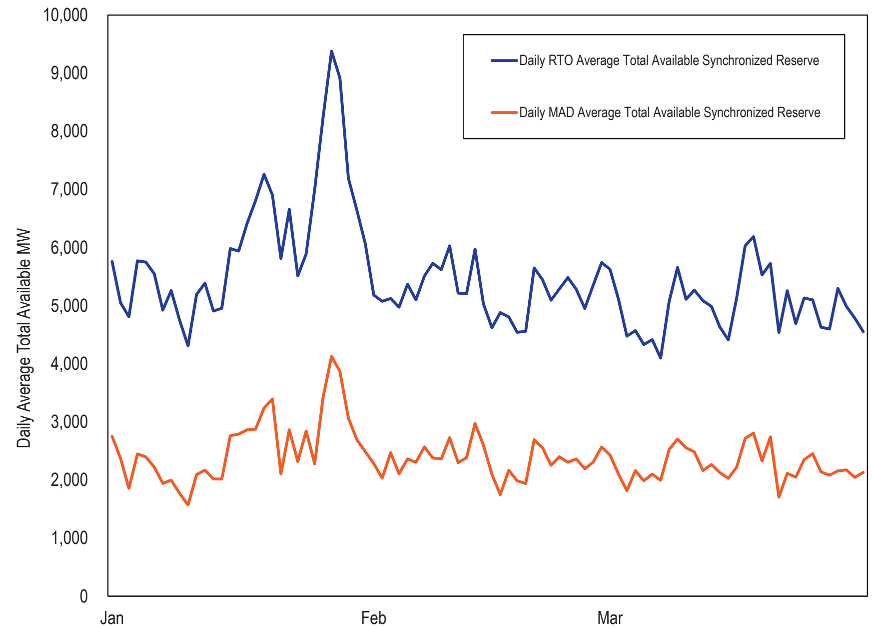
Figure 10-12 Number of units per day allowed to use a spin max less than eco max:[76] October 2022 through March 2026



In the first three months of 2026, the average supply of offered and eligible synchronized reserve was 5,453.7 MW in the RTO Reserve Zone, of which 2,384.9 MW was located in the MAD Reserve Subzone. Figure 10-13 shows the daily average available synchronized reserve MW in the first three months of 2026. The daily average total available synchronized reserve MW increased in late January due to PJM committing more resources to be online during a cold weather event which included Winter Storm Fern.

76 That a unit is able to use a spin maximum less than its economic maximum does not mean that it is required to do so. The count of units that used the exception on a given day can be less than what is shown.

Figure 10-13 Daily Average Available Synchronized Reserve: January through March, 2026



Market Concentration

Table 10-15 provides the average HHI and the percent of intervals during which the maximum market share was above 20 percent for the day-ahead and real-time synchronized reserve markets for the first three months of 2026. In the first three months of 2026, the MAD synchronized reserve market was highly concentrated in the day-ahead market and highly concentrated in the real-time market. In the first three months of 2026, the RTO synchronized reserve market was unconcentrated in the day-ahead market and unconcentrated in the real-time market.

Table 10-15 Day-ahead and real-time synchronized reserve average HHI: January through March, 2026

Location	Market	Average HHI	Percent of Intervals Max Market Share Above 20%	Description
RTO	RT	901	23.8%	Unconcentrated
RTO	DA	922	24.4%	Unconcentrated
MAD	RT	1989	92.3%	Highly Concentrated
MAD	DA	1800	90.9%	Highly Concentrated

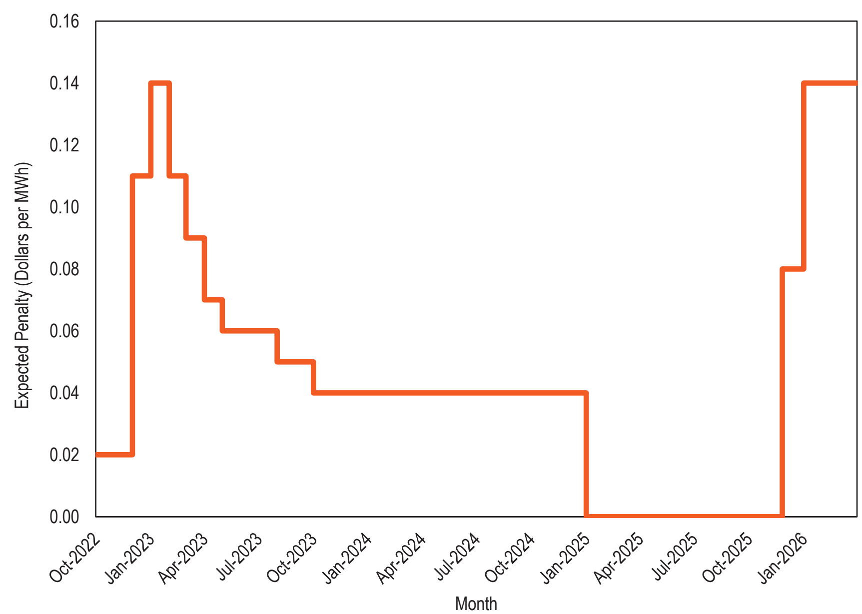
In the first three months of 2026, the Ancillary Service Optimizer, which schedules economic inflexible resources while considering all resources against forecasted LMPs, failed the three pivotal supplier test in 2,210 ASO intervals, 60.2 percent of the 3,671 ASO intervals to which the test applied.[77]

Market Behavior

The synchronized reserve offer price must be cost based and is capped at the expected value of the synchronized reserve penalty, which equals the average penalty multiplied by the average rate of nonperformance multiplied by the probability that an event will occur.[78] These expected values are shown in Figure 10-14. For resources that do not provide an offer price, the offer price is treated as $0 per MWh. In the first three months of 2026, the weighted average offer price for generators that set their offer MW was $0.00 per MWh. In the first three months of 2026, the weighted average offer price for DSR resources that set their offer MW was $0.04 per MWh.

The synchronized reserve offer cap was updated monthly from October 2022 through December 2023, after which it is updated annually. On November 26, 2025, the offer cap was increased from $0.00 to $0.08 to correct for an error.[79] For 2026, the offer cap is $0.14 per MWh.

Figure 10-14 Expected values of the synchronized reserve penalty: October 2022 through March 2026[80]



Market Performance

In the first three months of 2026, the real-time RTO weighted average synchronized reserve market clearing price (SRMCP) was $6.38 per MWh and the day-ahead RTO weighted average SRMCP was $7.50 per MWh. The real-time MAD weighted average SRMCP was $6.23 per MWh and the day-ahead MAD weighted average SRMCP was $8.11 per MWh. In the first three months of 2026, there were 25,908 five-minute intervals in the real-time market and there were 2,159 hours in the day-ahead market. The real-time RTO SRMCP was $0 per MWh in 12,135 intervals (46.8 percent of all intervals). The real-time MAD SRMCP was $0 per MWh in 12,134 intervals (46.8 percent of all intervals). The day-ahead RTO SRMCP was $0 per MWh in 484 hours (22.4

77 On October 1, 2025, the ASO switched from producing one-hour solutions to producing 30-minute solutions. Although the ASO's intervals are now 30 minutes long, the ASO still schedules reserves in one-hour blocks, each of which now span two 30-minute intervals.
78 See PJM. "PJM Manual 15: Cost Development Guidelines," § 4.7 Synchronized Reserve, Rev. 47 (Oct. 1, 2025).
79 See PJM. "Synchronized Reserve Offer Cap", 2025 Annual Calculation (Dec. 12, 2025). <https://www.pjm.com/-/media/DotCom/markets-ops/ancillary/synchronized-reserve-offer-cap-2025.xlsx>
80 PJM. "Synchronized Reserve Offer Cap". December 12, 2025. <https://www.pjm.com/-/media/markets-ops/ancillary/synchronized-reserve-offer-cap-penalty.ashx>.

percent of all hours). The day-ahead MAD SRMCP was $0 per MWh in 218 hours (10.1 percent of all hours).

Figure 10-15 shows the daily unweighted average prices for synchronized reserve in the real-time and day-ahead markets. Higher day-ahead prices in late January and early February occurred during a cold weather event that included Winter Storm Fern, for which conservative operations were declared, a cold weather alert was issued, and maintenance outages were recalled. Shortage pricing for the RTO and MAD was used on January 23 and March 12. Shortage pricing for the RTO was used on January 30; February 1, 4, 6, and 7; and March 1, 13, and 14.

Figure 10-15 Day-ahead and real-time synchronized reserve average market clearing prices: January through March, 2026

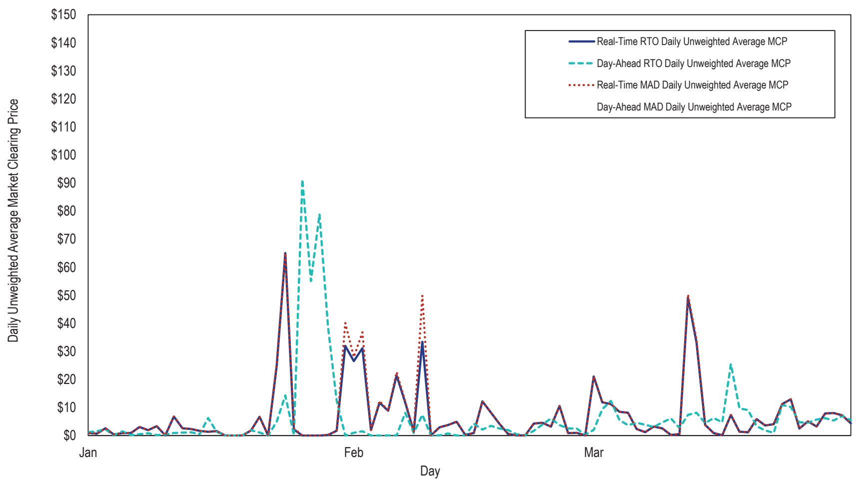


Table 10-16 and Table 10-17 compare the dispatch run and pricing run weighted average prices for the day-ahead and real-time markets. Fast start pricing increases LMP in the pricing run relative to the dispatch run, which increases reserve prices. Fast start pricing also reduces the amount of reserves available in the pricing run compared to the dispatch run, by pretending that fast start units can be dispatched for energy below their economic minimum output limit but not counting MW below the eco min as reserves. For the real-time values, these are the LPC prices weighted using the RT SCED MW. For the day-ahead values, these are the DA prices weighted using the DA dispatch MW. PJM dispatchers can update assignments after RT SCED has run, so these weights differ from the weighted average value reported elsewhere in this section.[81] In the first three months of 2026, the real-time RTO weighted average price from the pricing run was 25.5 percent higher than the real-time RTO weighted average price from the dispatch run. In the first three months of 2026, the day-ahead RTO weighted average price from the pricing run was 1.8 percent higher than the day-ahead RTO weighted average price from the dispatch run. In the first three months of 2026, the real-time MAD weighted average price from the pricing run was 22.2 percent higher than the real-time MAD weighted average price from the dispatch run. In the first three months of 2026, the day-ahead MAD weighted average price from the pricing run was 6.8 percent higher than the day-ahead MAD weighted average price from the dispatch run.

81 See PJM. "PJM Manual 01: Control Center and Data Exchange Requirements," § 1.7 Dispatch Management Tool (DMT), Rev. 50 (May 21, 2025).

Table 10-16 Day-ahead and real-time fast start pricing in the RTO synchronized reserve market: January 2025 through March 2026

		Day-Ahead				Real-Time			
Year	Month	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference
2025	Jan	$4.43	$4.79	$0.36	8.0%	$2.02	$2.62	$0.61	30.1%
2025	Feb	$2.56	$2.56	($0.00)	(0.1%)	$1.96	$2.88	$0.92	46.9%
2025	Mar	$7.73	$7.23	($0.50)	(6.5%)	$4.89	$7.28	$2.39	48.9%
2025	Apr	$8.65	$8.48	($0.17)	(2.0%)	$2.64	$4.91	$2.28	86.4%
2025	May	$5.77	$5.45	($0.32)	(5.6%)	$2.15	$3.14	$0.99	45.7%
2025	Jun	$7.96	$7.51	($0.44)	(5.6%)	$9.48	$10.77	$1.29	13.6%
2025	Jul	$10.69	$9.98	($0.70)	(6.6%)	$2.87	$4.67	$1.80	62.8%
2025	Aug	$3.78	$3.22	($0.55)	(14.6%)	$1.24	$2.03	$0.79	63.9%
2025	Sep	$5.66	$4.69	($0.97)	(17.1%)	$2.77	$3.42	$0.65	23.3%
2025	Oct	$6.50	$6.44	($0.06)	(0.9%)	$2.53	$3.59	$1.07	42.1%
2025	Nov	$5.37	$4.00	($1.37)	(25.5%)	$1.02	$1.62	$0.60	58.3%
2025	Dec	$3.16	$2.59	($0.58)	(18.2%)	$1.90	$2.61	$0.71	37.2%
2025	All	$6.08	$5.62	($0.46)	(7.5%)	$2.96	$4.10	$1.14	38.6%
2026	Jan	$10.61	$11.51	$0.90	8.5%	$3.29	$4.67	$1.37	41.7%
2026	Feb	$2.98	$2.15	($0.83)	(27.8%)	$5.66	$6.98	$1.32	23.3%
2026	Mar	$6.76	$6.89	$0.13	1.9%	$6.42	$7.55	$1.13	17.7%
2026	All	$7.05	$7.18	$0.13	1.8%	$5.01	$6.29	$1.28	25.5%

Table 10-17 Day-ahead and real-time fast start pricing in the MAD synchronized reserve market: January 2025 through March 2026

		Day-Ahead				Real-Time			
Year	Month	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference
2025	Jan	$5.11	$5.53	$0.42	8.2%	$2.15	$2.68	$0.54	25.1%
2025	Feb	$4.02	$4.02	($0.00)	(0.1%)	$1.67	$2.40	$0.73	43.6%
2025	Mar	$8.08	$7.58	($0.49)	(6.1%)	$4.47	$6.65	$2.18	48.9%
2025	Apr	$9.09	$8.92	($0.17)	(1.8%)	$2.41	$4.11	$1.71	70.9%
2025	May	$5.94	$5.60	($0.34)	(5.7%)	$1.92	$2.81	$0.88	45.9%
2025	Jun	$8.17	$7.74	($0.44)	(5.3%)	$7.76	$8.52	$0.77	9.9%
2025	Jul	$10.69	$9.97	($0.72)	(6.7%)	$2.74	$4.37	$1.63	59.7%
2025	Aug	$3.98	$3.46	($0.52)	(13.0%)	$1.16	$1.91	$0.75	64.5%
2025	Sep	$5.42	$4.51	($0.90)	(16.7%)	$2.61	$3.16	$0.55	21.1%
2025	Oct	$6.70	$6.69	($0.02)	(0.3%)	$2.35	$3.18	$0.83	35.4%
2025	Nov	$6.16	$6.36	$0.20	3.2%	$1.81	$2.33	$0.52	28.8%
2025	Dec	$6.32	$6.49	$0.17	2.7%	$5.49	$6.61	$1.11	20.2%
2025	All	$6.57	$6.32	($0.24)	(3.7%)	$3.01	$4.01	$1.00	33.4%
2026	Jan	$13.16	$14.46	$1.30	9.9%	$3.52	$4.99	$1.47	41.7%
2026	Feb	$3.40	$3.65	$0.25	7.3%	$5.69	$7.04	$1.35	23.8%
2026	Mar	$7.46	$7.60	$0.14	1.8%	$6.52	$7.09	$0.58	8.8%
2026	All	$8.24	$8.80	$0.56	6.8%	$5.13	$6.27	$1.14	22.2%

Figure 10-16 shows the dispatch-run synchronized reserve RTO market clearing prices of the day-ahead software (DA), the hour-ahead software (ASO), and the real-time software (RT SCED). The pricing-run market clearing prices, calculated by the LPC, are in Figure 10-15. As seen in Figure 10-16, there can be significant differences in the dispatch-run clearing prices. The ASO schedules units by forecasting least-cost outcomes for the operating hour, and any inflexible resources cleared by the ASO are automatically cleared by RT SCED. Because it is possible for real time to differ from the ASO's forecasts, it is possible for an inflexible resource to be scheduled during real-time conditions in which, had it not been inflexible and already cleared by the ASO, RT SCED would not have scheduled it. For example, it is possible for an inflexible resource to be scheduled in real time even when its bid price is higher than the clearing prices used by RT SCED and the LPC. This did not occur in 2025, or in 2026, but in 2024, there were 47,229 RT SCED five-minute intervals in which there was at least one inflexible unit scheduled by the ASO whose bid price was greater than the RT SCED market clearing price. In 2024, there were 229 inflexible resources cleared by the ASO for which the market clearing price of the RT SCED five-minute interval was less than the resource's bid price. The opposite can also happen, in which an inflexible resource is not cleared by the ASO while its offer parameters, had it not been inflexible, would have led to it having been cleared by RT SCED.

Figure 10-16 Dispatch run synchronized reserve market clearing prices from the day-ahead software, the ASO, and RT SCED: January through March, 2026

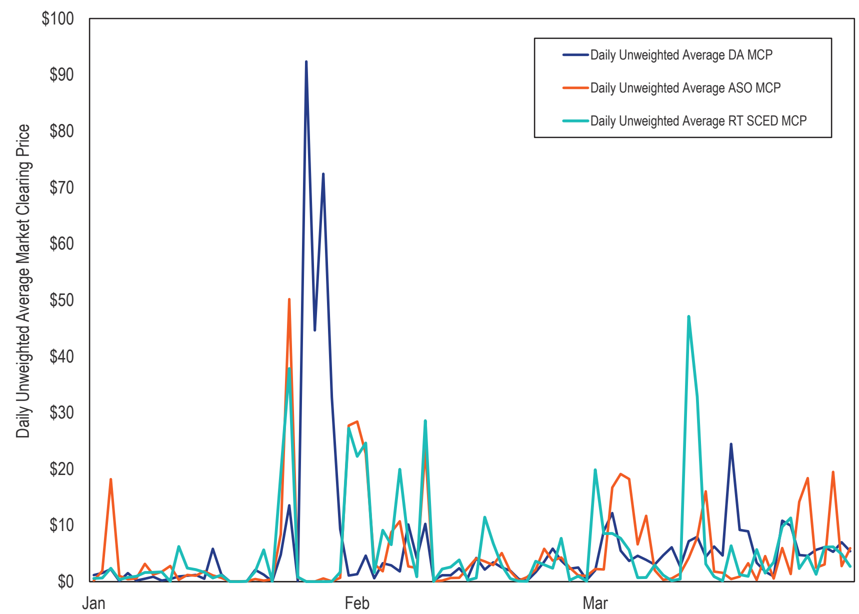


Table 10-18 shows total synchronized reserve payments by month for January 2025 through March 2026. Balancing credits for all but one month are negative, because, on average, resources buy back their day-ahead positions at higher real-time prices. LOC credits are paid to cover negative balancing credits if PJM converted a resource's day-ahead reserve position to energy in the real-time market. LOC credits are also paid to inflexible reserves when prices do not cover their opportunity costs. Shortfall charges are incurred by resources that do not provide their cleared reserve positions in real time. In Table10-18, the only months with synchronized reserve events that lasted for 10 or more minutes were February 2025, July 2025, September 2025 through November 2025, and March 2026, so there are no shortfall charges possible outside of those months. Total credits in June 2025 were larger due to price spikes during a hot weather event in which shortage pricing was used for synchronized reserve in the RTO Reserve Zone and the MAD Reserve Subzone. Total credits in July 2025 were larger due to price spikes during a second set hot weather event in which PJM declared hot weather alerts, emergency maximum generation alerts, and a maintenance outage recall. Shortage pricing was not used for synchronized reserve during the July hot weather event. Total credits in January 2026 were larger due to price spikes during a cold weather event covering Winter Storm Fern, in which PJM declared cold weather alerts, conservative operations, and a maintenance outage recall.

Table 10-18 Total synchronized reserve payments and charges by month: January 2025 through March 2026

Year	Month	Total Day-Ahead Credits	Total Balancing MCP Credits	Total LOC Credits	Total Shortfall Charges	Total Credits
2025	Jan	$9,766,427	($93,903)	$1,086,575	$0	$10,759,099
2025	Feb	$5,437,781	($126,526)	$779,549	$118,146	$5,972,657
2025	Mar	$15,181,061	($1,464,818)	$2,047,513	$0	$15,763,757
2025	Apr	$13,256,012	($345,197)	$1,268,522	$0	$14,179,338
2025	May	$10,685,430	($13,743)	$786,811	$0	$11,458,498
2025	Jun	$15,012,782	($4,327,200)	$4,657,382	$0	$15,342,965
2025	Jul	$22,507,389	($310,371)	$2,566,238	$76,684	$24,686,572
2025	Aug	$7,390,714	$20,554	$1,016,144	$0	$8,427,413
2025	Sep	$10,131,551	($840,026)	$1,576,176	$159,581	$10,708,120
2025	Oct	$11,138,947	($485,436)	$1,526,784	$114,170	$12,066,126
2025	Nov	$9,137,073	($11,535)	$1,375,185	$4,336	$10,496,388
2025	Dec	$9,324,827	($435,351)	$1,998,439	$0	$10,887,915
2025	All	$138,969,996	($8,433,550)	$20,685,319	$472,917	$150,748,848
2026	Jan	$23,153,558	($231,344)	$2,986,156	$0	$25,908,371
2026	Feb	$4,348,346	($1,100,363)	$3,640,493	$0	$6,888,476
2026	Mar	$13,523,239	($1,974,988)	$3,056,498	$299,649	$14,305,100
2026	All	$41,025,143	($3,306,695)	$9,683,147	$299,649	$47,101,946

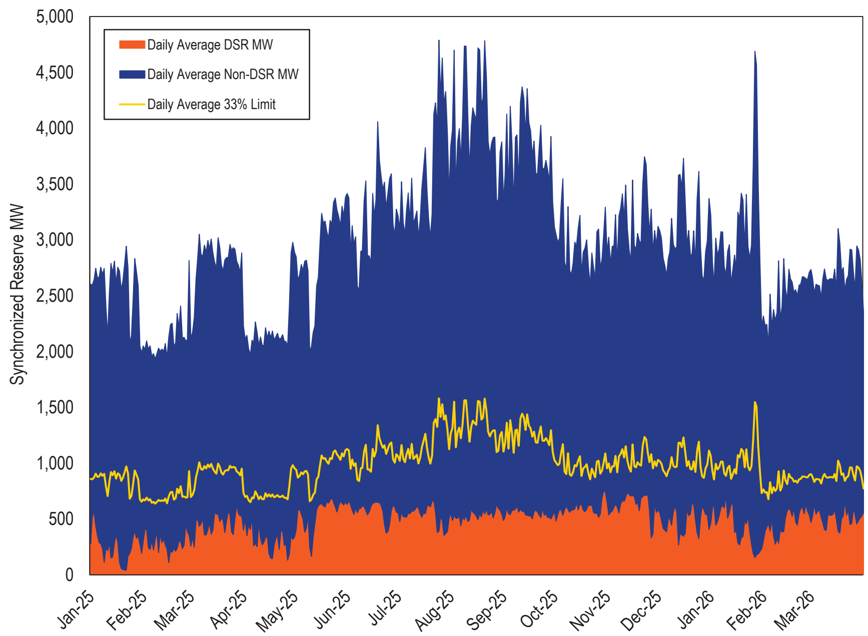
Table 10-19 provides the day-ahead and real-time synchronized reserve by resource type and fuel type for the first three months of 2026. For synchronized reserve, the MW for which a resource is credited at the market clearing price is capped at the lesser of its real-time assignment and the difference between its real-time output and the lesser of its economic maximum and its real-time reserve maximum. During spin events, this capped value is equal to the cleared MW. As it is this capped value for which a resource is credited, Table 10-19 only shows the capped value, excluding the additional cleared MW.

Table 10-19 Day-ahead and real-time synchronized reserve by resource type and fuel type: January through March, 2026

Resource / Fuel Type	Day-Ahead MWh	Real-Time Capped MWh	Day-Ahead Credits	Balancing MCP Credits	LOC Credits	Shortfall Charges	Total Credits
Combined Cycle	2,432,519	1,941,018	$18,144,761	($6,138,620)	$4,335,816	$84,893	$16,257,064
CT - Natural Gas	337,358	727,891	$7,884,450	$1,523,908	$1,346,466	$815	$10,754,009
Steam - Coal	931,381	1,198,616	$2,560,869	$1,888,327	$1,781,490	$34,869	$6,195,817
DSR	701,933	1,012,352	$3,647,887	$1,456,883	$1,140,515	$67,639	$6,177,646
Hydro - Pumped Storage	469,815	466,704	$3,907,443	($1,137,866)	$200,618	$89,698	$2,880,497
Hydro - Run of River	283,258	142,044	$2,238,995	($480,470)	$4,534	$12,984	$1,750,076
CT - Oil	107,220	128,529	$1,328,947	($296,069)	$345,516	$0	$1,378,395
Steam - Natural Gas	108,493	141,589	$729,964	$190,846	$264,469	$2,533	$1,182,746
Steam - Other	13,139	4,390	$90,952	($40,551)	$162,808	$83	$213,125
RICE - Natural Gas	11,037	6,657	$205,227	($26,502)	$21,311	$0	$200,036
RICE - Other	54,267	26,695	$214,052	($212,477)	$32,722	$6,135	$28,163
Other	20,312	17,581	$71,596	($34,102)	$46,882	$0	$84,375

The October 1, 2022, changes, removed the prior cap that limited DSR to 33 percent of the cleared synchronized reserves. In the first three months of 2026, real-time DSR was more than 33 percent of the cleared real-time synchronized reserves in 255 five-minute intervals, 1.0 percent of the total 25,908 five-minute intervals. In the first three months of 2026, day-ahead DSR was more than 33 percent of the cleared day-ahead synchronized reserves in one hours. During these 255 five-minute intervals, on average, DSR made up 38.0 percent of the synchronized reserve MW. Figure 10-17 shows the portion of synchronized reserve provided by DSR. Since September 2023, there has been an increase in the use of DSR, but not enough to frequently exceed the former limit.

Figure 10-17 Daily average synchronized reserve from DSR and non-DSR: January 2025 through March 2026



Synchronized Reserve Performance

Resources providing synchronized reserves are paid for being available to respond to a synchronized reserve event and not for the actual response. Synchronized reserve resources are paid for their output in the energy market when they respond to an event.

Actual synchronized reserve event response is determined by final output minus initial output where final output is the largest output between 9 and 11 minutes after the start of the event, and initial output is the lowest output between one minute before the event and one minute after the event.[82]

Cleared synchronized reserve resources are obligated to sustain their final output for the shorter of the length of the event or 30 minutes. The owner of a cleared resource is penalized if it fails to perform during any synchronized reserve event lasting 10 minutes or longer, although the resource owner can use overperformance from another resource to offset those losses. As synchronized reserve resources are allowed 10 minutes to ramp up to their cleared output, performance penalties are not assessed for events lasting less than 10 minutes.

Table 10-20 shows synchronized reserve event response compliance for events that lasted 10 minutes or longer, using only the response from cleared synchronized reserves. In 2024, five events were 10 minutes or longer. Of those five reserve events, only one was associated with a DCS event. In the first three months of 2026, one event lasted for at least 10 minutes. That one 10 minute event was due to a unit trip and was associated with a DCS event. In the first three months of 2026, PJM triggered zero events explicitly due to low ACE. For all other DCS events, any associated reserve event lasted less than 10 minutes. PJM has the option, but not the obligation, to trigger a reserve event in response to a DCS event. In some circumstances, PJM system operators will opt to recover the system via regulation and the normal dispatching process.

Actual synchronized reserve response is the total increase in MW from all synchronized reserve resources from the moment the spinning event is called to 10 minutes after. The overall response to spinning events was adequate or more than adequate to meet NERC requirements, in which the Reporting ACE must return to the lesser of zero and the value of the Reporting ACE before the disturbance that caused the event.[83] PJM, in practice, not only corrects the Reporting ACE disturbance that led to the event but over corrects. In the one event lasting 10 or more minutes in the first three months of 2026, the Reporting ACE recovered not just to the NERC required level of zero but overshot by approximately 1,000 MW.

82 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.10 Settlements, Rev. 136 (Oct. 1, 2025).

83 See PJM. "PJM Manual 12: Balancing Operations," Rev. 56 (Oct. 1, 2025) Attachment D.

Table 10-20 Response compliance for synchronized reserve events 10 minutes or longer by primary fuel and resource type, excluding over response: January 2025 through March 2026[84]

Spin Event	Duration (Minutes)	Primary Resource/Fuel Type	Total Synchronized Reserve Deployed (MW)	Total Capped Synchronized Reserve Resource Response (MW)	Total Synchronized Reserve Resource Shortfall (MW)	Synchronized Reserve Response Percent	Total Synchronized Reserve Response,including Over-Response (MW)	Synchronized Reserve Response Percent, including Over-Response
5-Feb-2025	10.0	Combined Cycle	548	411	137	75%	627	115%
		CT - Natural Gas	559	513	46	92%	563	101%
		Steam - Coal	199	106	93	53%	119	60%
		Steam - Natural Gas	120	42	78	35%	46	38%
		Other	412	180	232	44%	267	65%
		Total	1,837	1,252	585	68%	1,623	88%
1-Jul-2025	10.6	Combined Cycle	780	661	119	85%	991	127%
		CT - Natural Gas	963	760	203	79%	848	88%
		DSR	544	406	138	75%	525	96%
		Steam - Coal	345	282	63	82%	332	96%
		Other	287	229	57	80%	237	83%
		Total	2,918	2,337	580	80%	2,933	101%
22-Jul-2025	10.5	Combined Cycle	1,071	909	162	85%	1,197	112%
		CT - Natural Gas	585	510	75	87%	652	112%
		DSR	548	439	110	80%	600	109%
		Steam - Coal	806	611	195	76%	708	88%
		Other	236	141	95	60%	147	62%
		Total	3,246	2,610	636	80%	3,304	102%
25-Sep-2025	10.7	Combined Cycle	813	608	205	75%	775	95%
		CT - Natural Gas	971	829	142	85%	949	98%
		DSR	589	491	98	83%	625	106%
		Hydro - Pumped Storage	376	262	114	70%	563	150%
		Steam - Coal	168	126	42	75%	127	75%
		Steam - Natural Gas, Other	95	52	44	54%	52	55%
		Other	220	198	22	90%	206	94%
		Total	3,232	2,566	666	79%	3,297	102%
17-Oct-2025	11.1	Combined Cycle	413	331	81	80%	488	118%
		CT - Natural Gas	228	228	-0	100%	299	131%
		DSR	644	595	49	92%	750	116%
		Steam - Coal, Natural Gas	433	292	141	68%	377	87%
		Other	618	446	173	72%	483	78%
		Total	2,336	1,893	444	81%	2,397	103%
28-Oct-2025	14.7	Combined Cycle	658	501	157	76%	693	105%
		CT - Natural Gas	222	58	164	26%	124	56%
		DSR	574	447	126	78%	551	96%
		Steam - Coal	320	250	70	78%	337	105%
		Steam - Natural Gas	181	100	81	55%	108	60%
		Other	61	32	29	53%	35	58%
		Total	2,015	1,389	627	69%	1,847	92%
11-Nov-2025	10.3	Combined Cycle	706	495	211	70%	697	99%
		CT - Natural Gas	304	270	34	89%	355	117%
		DSR	673	610	63	91%	783	116%
		RICE - Natural Gas	43	40	2	95%	44	103%
		Steam - Coal	303	266	37	88%	301	99%
		Steam - Natural Gas	176	119	57	67%	143	81%
		Other	474	454	20	96%	506	107%
		Total	2,679	2,254	425	84%	2,829	106%
1-Mar-2026	11.15	Combined Cycle	538	363	175	67%	578	107%
		CT - Natural Gas	437	435	3	99%	508	116%
		DSR	643	499	144	78%	592	92%
		Hydro	470	195	276	41%	241	51%
		Steam - Coal	391	316	74	81%	380	97%
		Other	59	25	34	42%	30	51%
		Total	2,537	1,832	705	72%	2,328	92%

84 Results for identified technologies shown only if they are consistent with PJM confidentiality rules.

In the first three months of 2026, compliance with calls to respond to the single synchronized reserve event was significantly less than 100 percent. Table 10-21 shows the average amount of cleared synchronized reserve MW that responded to events 10 minutes or longer from 2017 through 2025. PJM experienced one event longer than 10 minutes in the first three months of 2026. In December 2024, PJM updated the economic basepoint signal to include deployed reserve MW during synchronized reserve events. This allowed resources to stay on AGC while responding to synchronized reserve events and led to improved average performance in 2025 and the first three months of 2026.

Table 10-21 Average synchronized reserve response from scheduled resources for events longer than 10 minutes, excluding over response: January 2017 through March 2026

Year	Number of Events of Any Length	Number of Events Longer than 10 Minutes	Average Percent of Scheduled Synchronized Reserve MW that Responded to Events Longer than 10 Minutes	Percent of Events that were Longer than 10 Minutes
2017	16	6	87.6%	37.5%
2018	18	8	74.2%	44.4%
2019	13	3	86.8%	23.1%
2020	17	5	59.5%	29.4%
2021	18	5	83.1%	27.8%
2022 (Jan - Sep)	14	3	71.2%	21.4%
2022 (Oct - Dec)	9	7	50.3%	77.8%
2023	12	3	55.6%	25.0%
2024	19	5	58.2%	26.3%
2025	28	7	78.3%	25.0%
2026	8	1	72.3%	12.5%

In Table 10-21, from January 2017 through September 2022, cleared synchronized reserve was provided by tier 2 synchronized reserves, which were cleared when the estimated response from tier 1 resources was insufficient to cover the requirement. Since October 1, 2022, the requirement is fully met by cleared resources that offer the new synchronized reserve product. In the new reserve market, most resources capable of providing reserves were required to offer their full capability as calculated by PJM, whereas previously resources had set their own offer MW. Additionally, while units still set their prices in the new market, the maximum allowed offer price was reduced. Under these new market rules, there was a much larger pool of resources offering synchronized reserves, but the resources clearing the reserve market changed. In the months immediately following the change, PJM was clearing less DSR and fewer natural gas CTs and more combined cycles and steam coal units, a portion of which had not cleared in the months leading up to the change. This, in part, lead to the drop in synchronized reserve performance seen in Table 10-21.

In 2024 and, to a lesser degree, in 2025 and the first three months of 2026, when PJM and the MMU inquired about poorly performing resources, responses pointed towards shortcomings in how resources were deployed. Although resources are required to fully respond within 10 minutes, resources do not necessarily have a full 10 minutes to respond. PJM schedules reserve MW with the expectation that resources will start responding as soon as an event begins, but this expectation fails to consider communication delays that result from how a resource's market operation center (MOC) notifies the resource of events. When a MOC receives PJM's ALL-CALL, it can take several minutes for the MOC to acknowledge the call and to contact the appropriate resources, which then can take minutes more to start responding.

The MMU recommends that, to minimize such lag, 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 to have the ability to automatically respond to the notifications. PJM currently has an optional inter-control room connection protocol (ICCP) signal that some control rooms use, but PJM does not track who is actually using it. This or another form of electronic signal should be required for all resources. On July 24, 2024, stakeholders approved a joint PJM/MMU proposal to implement an electronic communications and reserve deployment process. On December 17, 2024, PJM implemented changes to augment the SCED dispatch signal to include reserve response during reserve events. However, this new process is not required for all synchronized reserve resources and does not replace the ALL-CALL. The new process mainly benefits units that automatically respond to the dispatch signal, such as by following AGC. Between December 17, 2024, and the end of

March 2026, there were eight events lasting 10 or more minutes with which to sufficiently test the augmented dispatch signal. For the event on February 5, 2025, PJM took explicit action to make the event last long enough for testing. As shown in Table10-21, following the signaling improvements, PJM saw an increase in average performance from 58.2 percent in 2024 to 78.3 percent in 2025.

The penalty structure when a resource fails to respond fully to a spinning event has two components. The first component is, for each interval during the day on which the event occurred, the forfeiture of awarded SRMCP credits in the amount of the lesser of the resource's capped synchronized reserve assignment during that interval and the resource's maximum shortfall MW during that day. The second component is a required return of SRMCP credits paid in the Immediate Past Interval (IPI), equal to the sum of, for each scheduled interval within the IPI, the SRMCP multiplied by the lesser of a resource's capped MW assignment during the penalized interval and the resource's penalty obligation for the day of the event. The IPI is defined as the average time, in number of days, since the start of the previous event over the previous two years or, if less, the number of days since the resource last failed to fully respond. For example, the maximum IPI for 2026 is 18 days and was calculated using the events from November 1, 2023, through October 31, 2025.[85]

There are several problems with this penalty structure.[86] First, resource owners are permitted to aggregate the response of multiple cleared reserve resources within the same portfolio, allowing owners to reduce the penalty obligation of a resource's underresponse by offsetting it with another scheduled resource's overresponse.[87] Second, the maximum IPI is calculated using events of any length, even though a resource is automatically considered compliant for events less than 10 minutes in length, artificially and significantly shortening the applied IPI. Third, the historical component of the penalty only applies to a resource's SRMCP credits, but not to LOC credits, even though a large portion of credits is awarded for LOC. For the one event that lasted for 10 or more minutes in the first three months of 2026, for each resource interval in which the resource's penalty obligation MW was greater than or equal to the resource's capped MW during the penalized interval, the total historical penalty was $81,812 and the total LOC credit was $12,389.

The penalty structure for synchronized reserve nonperformance does not provide appropriate or reasonable performance incentives. Under the current penalty structure and due to the low frequency of sufficiently long events, it is possible for a resource to not respond to any spin events and yet still receive net revenues for providing synchronized reserve. The MMU continues to recommend that the penalty's repayment include the LOC credits in addition to the SRMCP credits. The MMU also recommends that a unit that fails to respond to a synchronized reserve event 10 minutes or longer repay all credits back to the last time that the unit successfully responded to an event 10 minutes or longer. A resource should not be paid for reserves that it does not provide.

The MMU also continues to recommend that aggregation not be permitted to offset resource specific penalties for failure to respond to a synchronized reserve event. Including aggregate responses from all cleared resources weakens the incentive to perform and creates an incentive to withhold reserves from other resources. Synchronized reserve commitment is resource specific, so the obligation to respond should also be resource specific.

Each row of Table 10-22 shows the possible total historical penalty if the historical penalty had been defined differently based on each of the MMU's recommendations in the first three months of 2026 for the one event lasting 10 or more minutes in length. It compares the status quo amount, the amount if the IPI were defined using only events of 10 or more minutes, the amount if LOC credits were penalized in an amount proportionate to the shortfall, and the amount if aggregate response were not allowed to offset shortfalls. As can be seen in the table, the values are similar for the status quo, for penalizing LOC credits, and for disallowing aggregate response. The larger effect of only using 10-minute events to calculate the IPI is due to using a 56-day IPI

85 See "2024 Third Quarter Synchronized Reserve Performance," PJM presentation to the Operations Committee. (December 5, 2024) <https://www.pjm.com/-/media/DotCom/committees-groups/committees/oc/2024/20241205/20241205-item-12---synchronous-reserve-update.pdf>.

86 See "IMM Proposal: Reserve Deployment and Compensation," IMM presentation to the Reserve Certainty Senior Task Force. (March 13, 2024) <https://pjm.com/-/media/committees-groups/task-forces/rcstf/2024/20240313/20240313-item-02---imm-proposal---deployment-and-compensation.ashx>.

87 See PJM. "PJM Manual 28: Operating Agreement Accounting," § 6.3 Charges for Synchronized Reserve, Rev. 102 (Oct. 1, 2025).

compared to PJM's current 18-day IPI. Table10-22 shows that redefining only a single component of the reserve penalty structure will not necessarily yield a large increase in penalties. All shortcomings of the current reserve penalty structure should be addressed.

Table 10-22 Comparison of historical/retroactive penalties using possible different definitions: January through March, 2026

Description	Total Retroactive Penalty
Status Quo	$330,003
Using only 10-minute events for IPI	$2,744,414
Including LOC credits in retroactive penalty	$389,305
Disallowing aggregate response	$352,767
All three changes	$3,390,648

Resources should not be paid for reserves that they do not provide. The MMU recommends reclaiming credits back to the last known fully compliant performance, while providing the opportunity to demonstrate performance between events. Resources do not control when PJM calls 10-minute events, nor do they control whether they are scheduled during the few 10-minute events that PJM calls. While actual performance is the key to not being penalized, those factors contribute to defining penalties for many resources. The solution is not to arbitrarily limit the penalized period, as PJM does with its IPI, but to instead provide opportunities, between events, for resources to demonstrate that they are capable of providing reserves.

PJM's 2023 Response to Poor Unit Specific Performance

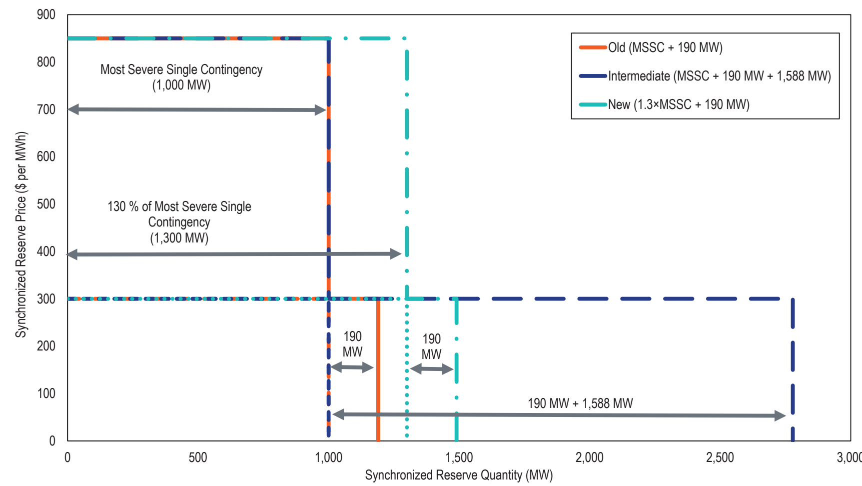
On October 1, 2022, PJM implemented substantial changes to the reserves markets, called Reserve Price Formation, meant to improve reserve reliability and improve accuracy when calculating reserve supply. Winter Storm Elliot occurred in December 2022. In the nine synchronized reserve events from October 2022 through April 2022, the average reserve performance was 53.7 percent. Excluding the events of Winter Storm Elliot, it was 49.4 percent.

In May 2023, in response to poor unit specific reserve performance since the market changes made on October 1, 2022, PJM made two unilateral decisions without approval from stakeholders or FERC. On May 12, 2023, PJM inappropriately increased the extended reserve requirement by 1,588 MW and on May 15, 2023, PJM reversed the increase. On May 19, 2023, PJM inappropriately increased the synchronized reserve reliability requirement by 30 percentage points to 130 percent of the most severe single contingency (MSSC). On January 9, 2026, PJM adjusted the synchronized reserve reliability requirement to be 120 percent of the MSSC.

This increase only applies to MSSCs located outside of the reserve subzone. If the RTO's MSSC is located inside the MAD Reserve Subzone (meaning that the MAD MSSC is also the RTO MSSC), then the adder is not used and the RTO and MAD reliability requirements are equal. Because the MAD Reserve Subzone's MSSC is always located within the subzone, the increase does not affect the MAD reserve requirements.

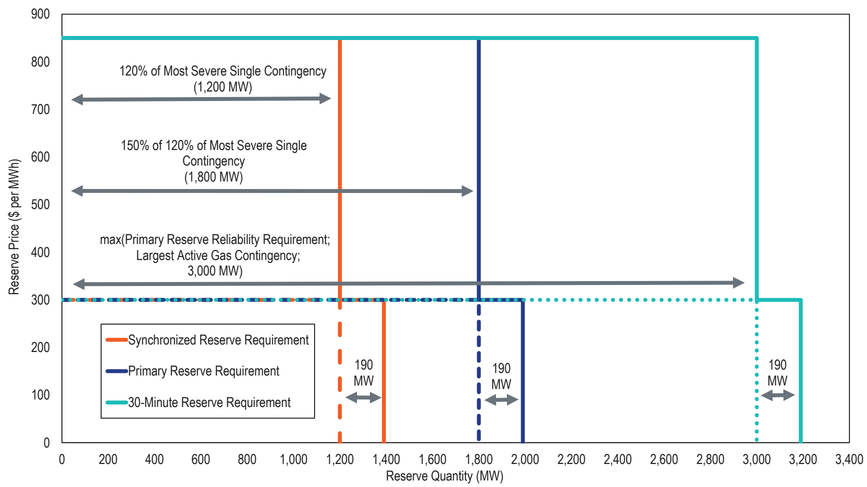
Figure 10-18 compares, for an example MSSC of 1,000 MW, the initial synchronized reserve ORDC from before these changes, the intermediate ORDC with the extension to the second step, and the new ORDC with the 30 percent increase in the first step.

Figure 10-18 An example comparison of the old, intermediate, and new real-time synchronized reserve ORDCs



Because the definitions of the reserve reliability requirements are nested, PJM's increase to the synchronized reserve reliability requirement also increased the primary reserve reliability requirement, which in turn could increase the 30-minute reserve reliability requirement. Figure 10-19 shows the new ORDCs of the three reserve services using an example MSSC of 1,000 MW and the default 190 MW for the extended requirements. Figure 10-6 shows the original ORDCs for the same example MSSC. As seen in Figure 10-2, although not shown in Figure 10-19, as a result of the increase, the 30-minute reserve requirement is now usually equal to the primary reserve requirement.

Figure 10-19 An example of the reserve services' new real-time operating reserve demand curves using the 20-percent increase, including the permanent second steps



PJM did not have the authority to increase the extended reserve requirements without a hot or cold weather alert or an emergency condition. The most common cause of doubled synchronized reserve requirements in the first four months of 2023 and in prior years was the possibility of large units tripping or being disconnected while undergoing maintenance work, which is a clear increase in the size of the most severe single contingency.

The doubling of the requirement for May 12 to May 16, 2023, lead to 31 intervals of shortage pricing for synchronized reserve and primary reserve in the RTO, even though, based on the actual contingencies, both services cleared well in excess of what was actually needed. In addition, because there was no spin event on either May 12 or May 15, it is unknown whether the response that could have been gained by this increase in demand justified these higher prices.

After making these changes, PJM later modified Manual 11 to allow "temporarily" increasing contingency reserve requirements "as necessary to account for resource performance."[88] Neither temporary nor resource performance criteria are specified or defined in the manual. PJM announced criteria for reducing the increase to the synchronized reserve reliability requirement in the PJM Operating Committee on March 6, 2025.[89]

PJM already clears additional 10-minute reserve in the form of nonsynchronized reserve. PJM had and continues to have the option to use all 10-minute reserve that it clears for recovering within 10 minutes, but instead chooses to increase the amount of all 10-minute reserve that PJM clears, even though it only uses a subset.[90] Despite PJM's unexplained reluctance to call a nonsynchronized reserve event, PJM does use NSR resources to respond to synchronized reserve events. That PJM occasionally uses certain nonsynchronized resources to respond to synchronized reserve events while wishing to avoid the general use of NSR suggests a mismatch between NSR's definition, its actual characteristics, and PJM's definition of its operational needs.

PJM gave several reasons to support the changes to the reserve ORDCs, including that resource response to spin events has been poor and that the average length of spin events greater than 10 minutes has increased. In addition, PJM was concerned that it might be less able to avoid Disturbance Control Standard (DCS) violations, in which PJM would exceed the NERC-

88 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 6.3 Charges for Synchronized Reserve, Rev. 136 (Oct. 1, 2025). "In order to meet Reliability First (RF) Regional Criteria, PJM may schedule additional Contingency Reserves on a temporary basis in order to meet the Largest Single Contingency, as necessary to account for resource performance. PJM shall post details regarding additional scheduling of reserves in Markets Gateway."

89 See "Synchronized Reserve Requirement for Reliability – Update," PJM presentation to the Operating Committee. (March 6, 2025) <https://www.pjm.com/-/media/DotCom/committees-groups/committees/oc/2025/20250306/20250306-item-08b---synchronized-reserve-adder.pdf> .

90 See PJM. "PJM Manual 12: Balancing Operations," § 4.1.2 Loading Reserves, Rev. 56 (Oct. 1, 2025).

imposed 15-minute limit for recovering Reporting ACE from changes due to Reportable Disturbances.[91] The MMU agrees about the underlying facts, with caveats, but does not agree with PJM's assertions about the reasons for poor performance, or with the assumption about DCS events or that any of these reasons support PJM's actions.

The MMU agrees that the average length of reserve events has increased, but notes that recent DCS event lengths have remained well below NERC's 15-minute requirement, except in two cases. The first case was on December 26, 2022, during Winter Storm Elliott, when PJM recovered from a DCS event in 15 minutes and 52 seconds. The second case was on July 27, 2025, during a summer hot weather event, when PJM recovered from a DCS event in 15 minutes and 41 seconds. Regardless, the data do not support the assertion that PJM is at risk of violating NERC standards during nonemergency conditions and the data do not support the assertion that there has been a change in PJM's DCS event response times. In general, PJM's recovery times are clearly and significantly shorter than NERC's 15-minute requirement and PJM's self-imposed 10-minute requirement. In many cases, PJM recovers Reporting ACE within five minutes. Figure 10-20 compares the lengths of recent DCS events with the lengths of their corresponding spin events. PJM triggers a spin event for most, but not all, DCS events. As can be seen, many spin events are minutes longer than the DCS event for which they were triggered. In the cases where a spin event continues for more than 10 minutes, this can mean that resource performance becomes subject to evaluation for spin events whose purpose had already been achieved minutes ago (that is, the recovery of the Reporting ACE and the end of the DCS event). While there are reasons for PJM dispatchers to continue a spin event even after ACE recovers, Figure 10-20 shows that the lengths of spin events do not suggest that PJM has become closer to having a DCS violation. Instead, it shows that the length of DCS events from immediately before and immediately after the implementation of Reserve Price Formation on October 1, 2022, are similar. It also demonstrates the effect of the improvement to reserve deployment since December 2024, in that all DCS events since the improvement were less than five minutes (one third of NERC's 15-minute requirement and half of PJM's 10-minute target).

91 See PJM. "PJM Manual 12: Balancing Operations," Rev. 56 (Oct. 1, 2025) Attachment D.

Figure 10-20 Comparison of DCS event lengths with corresponding spin event lengths: January 2021 through March 2026[92]

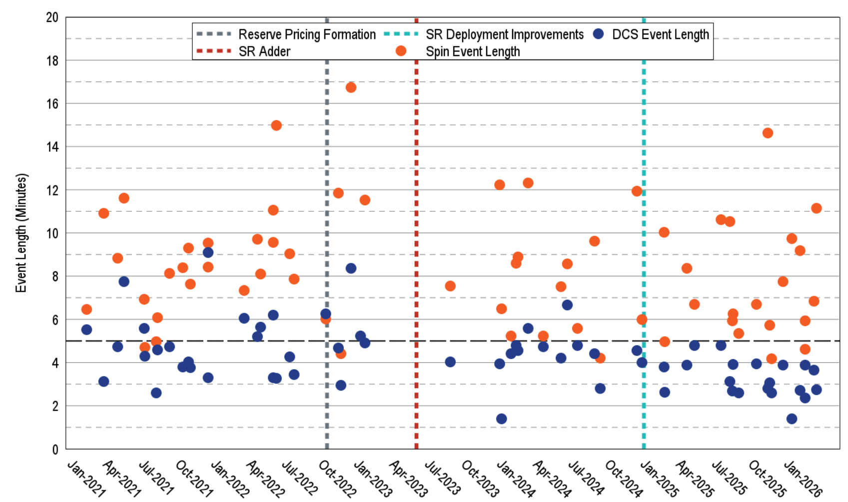


Table 10-23 lists the DCS events and corresponding spin events shown in Figure 10-21.

92 This chart previously showed the SR deployment improvement starting on December 17, 2023, instead of the correct date, December 17, 2024.

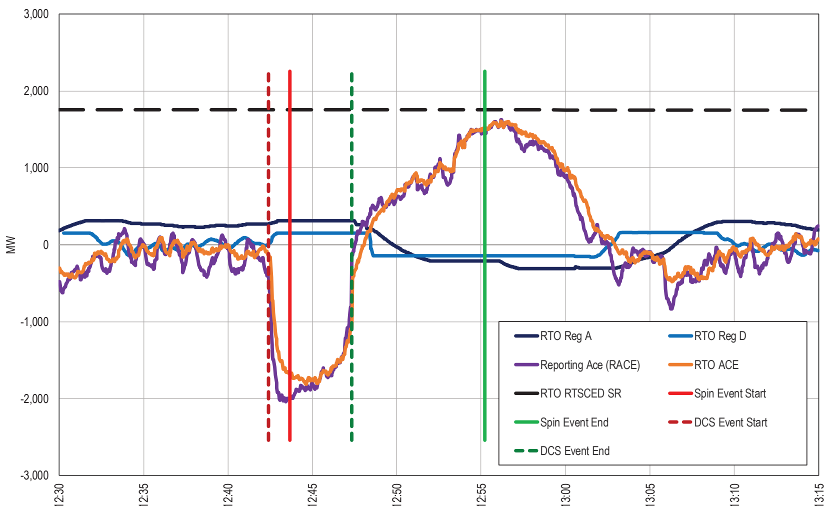
Table 10-23 Comparison of DCS event lengths with corresponding spin event lengths: January 2021 through March 2026[93]

DCS Start	DCS End	DCS Length	Spin Start	Spin End	Spin Length
03-Mar-2022 1218 (EPT)	03-Mar-2022 1224 (EPT)	00:06:03	03-Mar-2022 1220 (EPT)	03-Mar-2022 1227 (EPT)	00:07:21
06-Apr-2022 1144 (EPT)	06-Apr-2022 1149 (EPT)	00:05:12	06-Apr-2022 1145 (EPT)	06-Apr-2022 1155 (EPT)	00:09:43
14-Apr-2022 0928 (EPT)	14-Apr-2022 0934 (EPT)	00:05:40	14-Apr-2022 0930 (EPT)	14-Apr-2022 0938 (EPT)	00:08:07
16-May-2022 1531 (EPT)	16-May-2022 1537 (EPT)	00:06:12	16-May-2022 1532 (EPT)	16-May-2022 1543 (EPT)	00:11:05
16-May-2022 1553 (EPT)	16-May-2022 1556 (EPT)	00:03:18	16-May-2022 1553 (EPT)	16-May-2022 1603 (EPT)	00:09:34
23-May-2022 1717 (EPT)	23-May-2022 1720 (EPT)	00:03:17	23-May-2022 1717 (EPT)	23-May-2022 1732 (EPT)	00:15:00
27-Jun-2022 1700 (EPT)	27-Jun-2022 1704 (EPT)	00:04:16	27-Jun-2022 1701 (EPT)	27-Jun-2022 1710 (EPT)	00:09:03
07-Jul-2022 1720 (EPT)	07-Jul-2022 1724 (EPT)	00:03:27	07-Jul-2022 1721 (EPT)	07-Jul-2022 1729 (EPT)	00:07:52
26-Sep-2022 0335 (EPT)	26-Sep-2022 0342 (EPT)	00:06:16	26-Sep-2022 0339 (EPT)	26-Sep-2022 0345 (EPT)	00:06:02
29-Oct-2022 0210 (EPT)	29-Oct-2022 0215 (EPT)	00:04:42	29-Oct-2022 0212 (EPT)	29-Oct-2022 0224 (EPT)	00:11:52
04-Nov-2022 1501 (EPT)	04-Nov-2022 1504 (EPT)	00:02:58	04-Nov-2022 1503 (EPT)	04-Nov-2022 1507 (EPT)	00:04:25
29-Nov-2022 1629 (EPT)	29-Nov-2022 1638 (EPT)	00:08:23	29-Nov-2022 1630 (EPT)	29-Nov-2022 1647 (EPT)	00:16:45
24-Dec-2022 0223 (EPT)	24-Dec-2022 0228 (EPT)	00:05:15	24-Dec-2022 0223 (EPT)	24-Dec-2022 0254 (EPT)	00:30:35
05-Jan-2023 1242 (EPT)	05-Jan-2023 1247 (EPT)	00:04:56	05-Jan-2023 1243 (EPT)	05-Jan-2023 1255 (EPT)	00:11:33
10-Aug-2023 0039 (EPT)	10-Aug-2023 0043 (EPT)	00:04:02	10-Aug-2023 0041 (EPT)	10-Aug-2023 0049 (EPT)	00:07:33
14-Dec-2023 1939 (EPT)	14-Dec-2023 1943 (EPT)	00:03:58	15-Dec-2023 0041 (EPT)	15-Dec-2023 0053 (EPT)	00:12:15
19-Dec-2023 0449 (EPT)	19-Dec-2023 0450 (EPT)	00:01:25	19-Dec-2023 1451 (EPT)	19-Dec-2023 1458 (EPT)	00:06:30
13-Jan-2024 0157 (EPT)	13-Jan-2024 0201 (EPT)	00:04:26	13-Jan-2024 0159 (EPT)	13-Jan-2024 0204 (EPT)	00:05:15
25-Jan-2024 1237 (EPT)	25-Jan-2024 1241 (EPT)	00:04:48	25-Jan-2024 1239 (EPT)	25-Jan-2024 1247 (EPT)	00:08:37
29-Jan-2024 1202 (EPT)	29-Jan-2024 1206 (EPT)	00:04:35	29-Jan-2024 1203 (EPT)	29-Jan-2024 1212 (EPT)	00:08:54
24-Feb-2024 1546 (EPT)	24-Feb-2024 1551 (EPT)	00:05:36	24-Feb-2024 1548 (EPT)	24-Feb-2024 1600 (EPT)	00:12:19
04-Apr-2024 1047 (EPT)	04-Apr-2024 1052 (EPT)	00:04:45	04-Apr-2024 1050 (EPT)	04-Apr-2024 1055 (EPT)	00:05:15
03-Jun-2024 1852 (EPT)	03-Jun-2024 1858 (EPT)	00:06:41	03-Jun-2024 1853 (EPT)	03-Jun-2024 1902 (EPT)	00:08:35
29-Jun-2024 2101 (EPT)	29-Jun-2024 2106 (EPT)	00:04:48	29-Jun-2024 2103 (EPT)	29-Jun-2024 2109 (EPT)	00:05:36
12-Aug-2024 1709 (EPT)	12-Aug-2024 1713 (EPT)	00:04:25	12-Aug-2024 1710 (EPT)	12-Aug-2024 1720 (EPT)	00:09:39
26-Aug-2024 1352 (EPT)	26-Aug-2024 1355 (EPT)	00:02:48	26-Aug-2024 1353 (EPT)	26-Aug-2024 1357 (EPT)	00:04:13
27-Nov-2024 1934 (EPT)	27-Nov-2024 1939 (EPT)	00:04:35	27-Nov-2024 1934 (EPT)	27-Nov-2024 1946 (EPT)	00:11:57
11-Dec-2024 0819 (EPT)	11-Dec-2024 0823 (EPT)	00:04:00	11-Dec-2024 0821 (EPT)	11-Dec-2024 0827 (EPT)	00:06:00
05-Feb-2025 1003 (EPT)	05-Feb-2025 1007 (EPT)	00:03:49	05-Feb-2025 1005 (EPT)	05-Feb-2025 1015 (EPT)	00:10:02
06-Feb-2025 1355 (EPT)	06-Feb-2025 1358 (EPT)	00:02:39	06-Feb-2025 1356 (EPT)	06-Feb-2025 1401 (EPT)	00:04:59
05-Apr-2025 0420 (EPT)	05-Apr-2025 0424 (EPT)	00:03:54	05-Apr-2025 0421 (EPT)	05-Apr-2025 0429 (EPT)	00:08:22
24-Apr-2025 0048 (EPT)	24-Apr-2025 0052 (EPT)	00:04:49	24-Apr-2025 0050 (EPT)	24-Apr-2025 0057 (EPT)	00:06:43
19-May-2025 1145 (EPT)	19-May-2025 1149 (EPT)	00:04:14	19-May-2025 1146 (EPT)	19-May-2025 1153 (EPT)	00:07:31
01-Jul-2025 1016 (EPT)	01-Jul-2025 1021 (EPT)	00:04:49	01-Jul-2025 1018 (EPT)	01-Jul-2025 1029 (EPT)	00:10:39
22-Jul-2025 1510 (EPT)	22-Jul-2025 1513 (EPT)	00:03:08	22-Jul-2025 1511 (EPT)	22-Jul-2025 1522 (EPT)	00:10:32
30-Jul-2025 1330 (EPT)	30-Jul-2025 1333 (EPT)	00:02:41	30-Jul-2025 1331 (EPT)	30-Jul-2025 1337 (EPT)	00:05:58
31-Jul-2025 0132 (EPT)	31-Jul-2025 0136 (EPT)	00:03:56	31-Jul-2025 0133 (EPT)	31-Jul-2025 0139 (EPT)	00:06:17
15-Aug-2025 1531 (EPT)	15-Aug-2025 1534 (EPT)	00:02:37	15-Aug-2025 1533 (EPT)	15-Aug-2025 1538 (EPT)	00:05:23
29-Sep-2025 2128 (EPT)	29-Sep-2025 2132 (EPT)	00:03:58	29-Sep-2025 2130 (EPT)	29-Sep-2025 2136 (EPT)	00:06:45
09-Jan-2026 2131 (EPT)	09-Jan-2026 2133 (EPT)	00:01:55	09-Jan-2026 2132 (EPT)	09-Jan-2026 2138 (EPT)	00:05:18
18-Jan-2026 0320 (EPT)	18-Jan-2026 0322 (EPT)	00:02:43	18-Jan-2026 0321 (EPT)	18-Jan-2026 0330 (EPT)	00:09:11
30-Jan-2026 1246 (EPT)	30-Jan-2026 1250 (EPT)	00:03:54	30-Jan-2026 1247 (EPT)	30-Jan-2026 1252 (EPT)	00:04:37
31-Jan-2026 0522 (EPT)	31-Jan-2026 0524 (EPT)	00:02:23	31-Jan-2026 0523 (EPT)	31-Jan-2026 0529 (EPT)	00:05:57
23-Feb-2026 0205 (EPT)	23-Feb-2026 0209 (EPT)	00:03:40	23-Feb-2026 0206 (EPT)	23-Feb-2026 0213 (EPT)	00:06:52
01-Mar-2026 1928 (EPT)	01-Mar-2026 1930 (EPT)	00:02:45	01-Mar-2026 1929 (EPT)	01-Mar-2026 1940 (EPT)	00:11:09

93 This chart previously showed the SR deployment improvement starting on December 17, 2023, instead of the correct date, December 17, 2024.

As an example of the differences between the lengths of spin events and the lengths of DCS events, Figure 10-21 shows PJM ACE during a DCS event and its corresponding spin event on January 5, 2023. The DCS event lasted 4 minutes and 56 seconds, while the spin event lasted 11 minutes and 33 seconds, more than twice as long. The DCS event ended when Reporting ACE (RACE) recovered to its level at the time of the loss of supply, while the spin event ended based on PJM discretion.

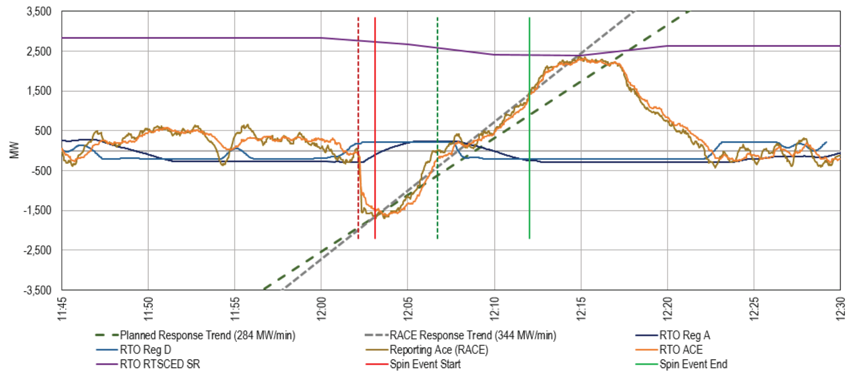
Figure 10-21 DCS Event vs. Spin Event: January 5, 2023



If the basis of the original definition of the synchronized reserve reliability requirement was an amount of MW needed to recover within 10 minutes, then an increase in the amount of cleared reserves can shorten the length of synchronized reserve events to be less than 10 minutes. In the remainder of 2023 after the increase in the reliability requirement in May 2023, there were eight spin events, of which seven were less than 10 minutes. Similarly, of the 19 spin events in 2024, 13 were less than 10 minutes. Of the 28 spin events in 2025, 21 were less than 10 minutes. Of the eight events in the first three months of 2026, PJM triggered only one event of 10 or more minutes. Because these shorter events lasted less than 10 minutes, only a small portion of the events since the increase qualify for performance assessment under the PJM Market Rules. PJM has stated that they monitor performance for events less than 10 minutes. If the PJM analysis fails to consider the lags that the ALL-CALL system introduces, different for each contacted resource, then it will continue to show underperformance.

In most of the spin events for the RTO Reserve Zone that have occurred since the reserve requirement increase in May 2023 through the first three months of 2026, including the events less than 10 minutes, ACE response is consistent with the rate of recovery that would be expected if reserves had performed adequately. Figure 10-22 shows one such event on January 29, 2024. However, some resources are responding to PJM's event notifications when they did not clear the reserve market, so they do not have reserve assignments during those events and so do not count towards reserve performance. PJM has defined the problem as one not of poor overall system response nor of poor ACE recovery, but one of poor performance from the assigned reserves. At the Operating Committee on March 6, 2025, PJM announced that they would decrease the adder to the synchronized reserve reliability requirement if average event performance were greater than 75 percent for qualifying events. Under these announced criteria, qualifying events would be any 10-minute event and any shorter event in which event performance was at least 75 percent. Even with these criteria, the fact that performance remains unsatisfactory for multiple events in the months with the increased requirements is evidence that the increase is not the correct solution to the asserted problem.

Figure 10-22 ACE response during a synchronized reserve event: January 29, 2024 from 12:03 to 12:12 EPT



The MMU disagrees with PJM that increasing the reserve requirement is the correct solution for accounting for poor reserve performance.[94] The MMU's position is that these problems with the supply of reserves should not be solved by changing the demand for reserves. The situation is a problem on the supply side, and it should be dealt with and solved on the supply side. The repeated lack of response means that resource personnel are insufficiently trained or that resource data inputs, such as ramp rates, the times needed for condensers to start, and economic maximums, are incorrect. It is the responsibility of market participants to correct their offer parameters and operating parameters. It is their obligation to submit correct data.

The data on synchronized reserve event recovery do not support the conclusion that there is an immediate need to change how reserves clear. If PJM insists on an immediate change, the focus should be on correcting the supply of reserves rather than increasing demand.

PJM's logic is that because reserves are responding at an average rate of about 50 percent during spin events, the solution is to buy twice as many MW of reserves. The result is that PJM is overpaying for reserve MW. PJM is paying for 1.0 MW but receiving 0.5 MW. PJM's solution is to pay for 2.0 MW in order to receive 1.0 MW.

Instead of increasing the demand requirement, the MMU proposes to purchase reserve MW from resources only in the amounts for which they can actually perform. If an underperforming resource's behavior shows that they can only reliably provide five MW of reserve, then PJM should only be purchasing five MW of reserve from them. PJM should not be paying MCP credits for MW that are not reliably provided, especially when it only recovers a portion of that money later via penalties and charges.

The MMU proposal is to pay for 0.5 MW from the underperforming unit. The MMU proposal is to pay for actual unit specific MW. The MMU proposal is to pay for 0.5 MW from each of two underperforming units. The result is to pay for 1.0 MW and to receive 1.0 MW of reserves. The MMU proposal is to buy the correct amount of reserves. No increase in demand is required.

The solution is not to buy more MW of poorly performing reserves. The solution is to accurately recognize the actual supply of reserves. The solution is to buy the correct amount of reserves, accounting for the actual performance of supply.

A focus on the supply side issues should be implemented immediately: ensure correct and timely signals; provide education on requirements; buy required reliable MW, based on actual performance; pay only for reliable MW based on actual performance; and do not pay for MW not provided. Detailed, unit by unit analysis of the reasons for poor performance is needed. Potential unit specific issues include: ensuring the ability to receive and respond to signals; discontinuities in offer curves; the accuracy of ramp rates; ambient derates; fuel availability; demand side resource response; failure to follow dispatch; incorrect eco max or spin max; and incorrect parameters.

One result of PJM's changes to the reserve requirements is that the total cost of the synchronized reserve market has increased. For May 2023 through December 2023, total credits paid for synchronized reserve were $66.7 million in eight months or $8.3 million per month, compared to $6.4 million in four

94 See "Market Monitor Report," MMU presentation to the Members Committee Webinar. (May 22, 2023) <https://pjm.com/-/media/committees-groups/committees/mc/2023/20230522-webinar/item-04---imm-report.ashx>.

months or $1.6 million per month for January 2023 through April 2023. In 2024, the total credits paid for synchronized reserve were $74.1 million or $6.2 million per month. In 2025, the total credits paid for synchronized reserve were $150.8 million or $12.6 million per month. In the first three months of 2026, the total credits paid for synchronized reserve were $47.1 million or $15.7 million per month. Table10-18 shows the total payments and charges for synchronized reserve by month. In the first three months of 2026, day-ahead credits to day-ahead synchronized reserve (which, as seen in Table10-18, is by far the largest contributor to total synchronized reserve credits) cleared in excess of the original day-ahead synchronized reserve requirement had the adder not been in place totaled $14.0 million. In 2025, such credits totaled $47.5 million. The cost of underperformance by reserve suppliers is paid by PJM customers, while it should be incurred by the suppliers who fail to meet their responsibilities. If reserve suppliers cannot provide the energy that they offer and clear during synchronized reserve events, they should not be paid from the last time they successfully responded to a spin event. These suppliers are not accurately representing their true capability to the PJM market and/or have failed to establish processes to ensure that they follow PJM's instructions.

On March 6, 2025, PJM presented to the PJM Operating Committee its criteria for decreasing (or increasing) the adder to the synchronized reserve reliability requirement by reviewing the average performance of non-overlapping sets of three qualifying events.[95] [96] A qualifying event is an event lasting at least 10 minutes or an event whose performance was at least 75 percent of the total reserve assignment. This performance is based on a resource's scheduled MW, not the MW amount that PJM uses its tools to deploy. Table10-24 shows the average performance required for each level of adjustment, with the adder not to exceed 30 percent of the most severe single contingency. In the first three months of 2026, there have been one event lasting 10 or more minutes out of eight events total. If synchronized reserve performs well in terms of its goal of restoring the system within 10 minutes, one would expect that the synchronized reserve event would last less than 10 minutes. As reserve performance improves following the improvement to synchronized reserve deployment in December 2024, it is possible for the larger reserve amounts cleared due to the adder to result in shorter synchronized reserve events, as more reserves are being deployed to cover supply losses less than or equal to the MSSC. If a synchronized reserve event lasts less than 10 minutes, one would expect that the reserve resources would not increase output by their full 10 minute ramp. Although PJM has included a way for shorter events to be considered for decreasing the adder, the 75 percent cutoff is arbitrary. That a shorter event does not achieve 75 percent performance in less than, for example, five minutes, is not necessarily indicative of a problem, because the only defining performance requirement for the synchronized reserve product is that it should achieve full performance by the tenth minute. Only events lasting 10 or more minutes can be true measures of under performance.

As shown by Table 10-20, poor performance is not an across the board problem, yet PJM's current criteria and approach treat it as if it were. Reserve supply issues are resource specific and should be addressed at the resource level, such as by requiring support for an electronic deployment signal. Increasing the requirement does not change resource behavior. Engaging with poorly performing resources, as the MMU and PJM have been doing, does change behavior. Reserve testing would allow PJM to identify underperforming resources that would benefit from unit specific engagement. Such identification would be proactive instead of reactive, improving event performance.

Table 10-24 PJM criteria for adjusting the adder in the synchronized reserve reliability requirement

Average Performance	Adder Adjustment
Below 70%	Increase by 10 percentage points
Above 75%	Decrease by 10 percentage points
Above 85%	Decrease by 20 percentage points
Above 95%	Decrease by 30 percentage points

95 See "Synchronized Reserve Requirement for Reliability – Update," PJM presentation to the Operating Committee. (March 6, 2025) <https://www.pjm.com/-/media/DotCom/committees-groups/committees/oc/2025/20250306/20250306-item-08b---synchronized-reserve-adder.pdf>.

96 See "Synchronized Reserve Requirement for Reliability – Update," PJM presentation to the Operating Committee. (May 8, 2025) <https://www.pjm.com/-/media/DotCom/committees-groups/committees/oc/2025/20250508/20250508-item-20---synchronized-reserve-for-reliability-update.pdf>.

History of Synchronized Reserve Events

Synchronized reserve is designed to provide relief for disturbances, which NERC calls “balancing contingency events”.[97] [98] Reportable balancing contingency events, from which PJM must recover within 15 minutes, are defined as the loss, within 60 seconds, of no more than the most severe single contingency (MSSC) and no less than lesser of 900 MW and 80 percent of the MSSC. In the absence of a disturbance, PJM operators have used synchronized reserve as a source of energy to provide relief from low ACE. Of the 28 events that occurred in 2025, four events were explicitly due to low ACE, of which all four events were less than 10 minutes. Of the eight events in the first three months of 2026, zero events were explicitly due to low ACE.

The risk of using synchronized reserves for energy or any other nondisturbance reason is that it reduces the amount of synchronized reserve available for a disturbance. Disturbances are unpredictable. Synchronized reserve has a requirement to sustain its output for 30 minutes at the most. When reserve output is still needed after 30 minutes, that output should come from secondary reserves, not synchronized reserves.

From January 2022 through March 2026, PJM experienced 90 synchronized reserve events, approximately 1.4 events per month, with an average duration of 10.9 minutes. Table10-25 shows these events with their region and their duration rounded to the nearest tenth of a minute.

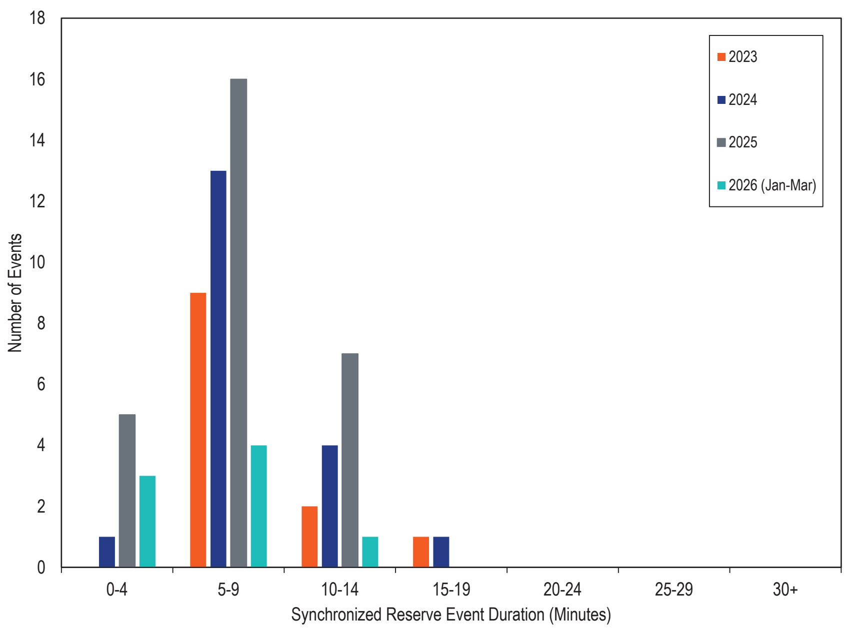
97 *2012 Annual State of the Market Report for PJM*, Appendix E – PJM's DCS Performance.
98 See PJM. "PJM Manual 12: Balancing Operations," § 4.1.2 Loading Reserves, Rev. 56 (Oct. 1, 2025).

Table 10-25 Synchronized reserve events: January 2022 through March 2026

Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)
03-Jan-2022 1227 (EPT)	RTO	8.9	13-Jan-2024 0159 (EPT)	RTO	5.3	21-Jan-2025 0520 (EPT)	RTO	4.7
03-Mar-2022 1220 (EPT)	RTO	7.4	25-Jan-2024 1239 (EPT)	RTO	8.6	05-Feb-2025 1505 (EPT)	RTO	10.0
06-Apr-2022 1145 (EPT)	RTO	9.7	29-Jan-2024 1203 (EPT)	RTO	8.9	06-Feb-2025 1856 (EPT)	RTO	5.0
13-Apr-2022 1725 (EPT)	RTO	28.5	24-Feb-2024 1548 (EPT)	MAD	12.3	11-Feb-2025 1404 (EPT)	RTO	5.3
14-Apr-2022 0931 (EPT)	RTO	8.1	04-Apr-2024 1050 (EPT)	RTO	5.3	05-Apr-2025 0421 (EPT)	RTO	8.4
16-May-2022 1532 (EPT)	RTO	11.1	13-Apr-2024 0036 (EPT)	RTO	7.1	24-Apr-2025 0050 (EPT)	MAD	7.1
16-May-2022 1553 (EPT)	RTO	9.6	03-Jun-2024 1853 (EPT)	RTO	8.6	19-May-2025 1146 (EPT)	RTO	7.5
23-May-2022 1717 (EPT)	RTO	15.0	29-Jun-2024 2103 (EPT)	RTO	5.6	22-Jun-2025 1937 (EPT)	RTO	7.8
26-May-2022 1409 (EPT)	RTO	6.3	08-Jul-2024 1757 (EPT)	RTO	14.5	01-Jul-2025 1018 (EPT)	RTO	10.6
22-Jun-2022 1506 (EPT)	RTO	7.2	18-Jul-2024 1524 (EPT)	RTO	7.0	22-Jul-2025 1511 (EPT)	RTO	11.5
27-Jun-2022 1701 (EPT)	RTO	9.1	21-Jul-2024 1753 (EPT)	RTO	10.2	30-Jul-2025 1331 (EPT)	RTO	6.0
07-Jul-2022 1721 (EPT)	RTO	7.9	12-Aug-2024 1710 (EPT)	RTO	9.7	31-Jul-2025 0133 (EPT)	RTO	6.3
26-Sep-2022 0339 (EPT)	RTO	6.0	18-Aug-2024 1604 (EPT)	RTO	15.9	06-Aug-2025 1849 (EPT)	MAD	7.9
29-Sep-2022 1025 (EPT)	RTO	6.2	26-Aug-2024 1353 (EPT)	RTO	4.2	14-Aug-2025 1740 (EPT)	RTO	4.3
29-Oct-2022 1412 (EPT)	RTO	11.9	22-Oct-2024 1002 (EPT)	RTO	6.2	15-Aug-2025 1533 (EPT)	RTO	5.4
04-Nov-2022 1503 (EPT)	RTO	4.4	10-Nov-2024 0020 (EPT)	RTO	10.8	04-Sep-2025 1956 (EPT)	RTO	9.0
14-Nov-2022 22:01 (EPT)	RTO	6.7	27-Nov-2024 1936 (EPT)	RTO	10.0	25-Sep-2025 1912 (EPT)	RTO	10.7
29-Nov-2022 1630 (EPT)	RTO	16.8	29-Nov-2024 1103 (EPT)	RTO	7.4	25-Sep-2025 1935 (EPT)	RTO	7.7
23-Dec-2022 1014 (EPT)	RTO	11.1	11-Dec-2024 0821 (EPT)	RTO	6.0	29-Sep-2025 2130 (EPT)	RTO	6.8
23-Dec-2022 1617 (EPT)	RTO	111.5				15-Oct-2025 1652 (EPT)	RTO	5.4
24-Dec-2022 0501 (EPT)	RTO	25.7				17-Oct-2025 1013 (EPT)	RTO	11.1
24-Dec-2022 0223 (EPT)	RTO	30.6				28-Oct-2025 1905 (EPT)	RTO	14.7
24-Dec-2022 0423 (EPT)	RTO	87.5				02-Nov-2025 1446 (EPT)	RTO	5.7
						06-Nov-2025 2240 (EPT)	RTO	4.2
05-Jan-2023 1243 (EPT)	RTO	11.6				11-Nov-2025 1004 (EPT)	RTO	10.3
10-Jan-2023 0706 (EPT)	RTO	17.5				05-Dec-2025 1930 (EPT)	RTO	4.4
26-Jan-2023 1452 (EPT)	MAD	6.9				06-Dec-2025 0505 (EPT)	RTO	7.8
02-Feb-2023 0606 (EPT)	RTO	8.0				28-Dec-2025 1707 (EPT)	RTO	9.8
28-May-2023 2009 (EPT)	RTO	7.4						
11-Jun-2023 1611 (EPT)	MAD	8.7				09-Jan-2026 2132 (EPT)	RTO	5.3
23-Jun-2023 1905 (EPT)	RTO	7.0				18-Jan-2026 0321 (EPT)	MAD	9.2
08-Aug-2023 0041 (EPT)	RTO	7.6				30-Jan-2026 1247 (EPT)	RTO	4.6
07-Nov-2023 1619 (EPT)	RTO	5.4				31-Jan-2026 0523 (EPT)	RTO	6.0
10-Nov-2023 0621 (EPT)	RTO	8.1				03-Feb-2026 1149 (EPT)	RTO	4.4
15-Dec-2023 0041 (EPT)	RTO	12.3				23-Feb-2026 0206 (EPT)	RTO	6.9
19-Dec-2023 0951 (EPT)	RTO	6.5				01-Mar-2026 1929 (EPT)	RTO	11.2
						05-Mar-2026 0224 (EPT)	RTO	4.0

Figure 10-23 shows spin event durations over the past 4 years. Events can last longer than 30 minutes. Beyond 30 minutes, reserves no longer have an obligation to perform. It is not clear what resources are instructed or expected to do after the 30-minute performance obligation. This ambiguity applies to three synchronized reserve events during Winter Storm Elliott in December 2022, which all lasted longer than 30 minutes.

Figure 10-23 Synchronized reserve events duration distribution curve: January 2023 through March 2026



Nonsynchronized Reserve

Nonsynchronized reserve (NSR), also called quick start reserve, consists of MW available within 10 minutes but not synchronized to the grid. Startup time for nonsynchronized reserve resources is not subject to testing and is based on the parameters in the energy offers submitted by resource owners. There is no defined requirement for nonsynchronized reserve; it is available to economically meet the primary reserve requirement. Generation resources that have designated their entire output as emergency are not eligible to provide nonsynchronized reserves. Generation resources that are not available to provide energy are not eligible to provide nonsynchronized reserves.

The nonsynchronized reserve market has a day-ahead and a real-time component. There are no lost opportunity costs for nonsynchronized reserve. Offline units cannot be dispatched to provide energy, because PJM has not called them to come online, so they do not have a lost opportunity to provide energy. As a result, the supply curve for nonsynchronized reserve has a price of zero and there are no uplift credits paid when LMP is higher than the incremental cost of nonsynchronized reserve units.

PJM defines the demand curve for nonsynchronized reserve, and PJM defines the supply curve based on nonemergency generation resources that are available to provide energy and can start in 10 minutes or less. Since nonsynchronized reserve is considered a lower quality product than synchronized reserve, its clearing price is less than or equal to the synchronized reserve market clearing price. In most market intervals, under usual circumstances, the nonsynchronized reserve market clearing price (NSRMCP) is $0 per MWh. However, due to PJM's increase of the synchronized reserve reliability requirement, there has been an increase in the number of intervals with nonzero NSRMCPs. For example, in 2024, over 60 percent of intervals had a non-zero NSRMCP. Table 10-26 shows the number of intervals with non-zero NSRMCPs in the first three months of 2026.

PJM uses nonsynchronized reserve when PJM calls nonsynchronized reserve events and when PJM calls specific nonsynchronized reserve resources to respond to synchronized reserve events. There were no nonsynchronized reserve events in the first three months of 2026.

Market Structure

Demand

There is no explicit demand for nonsynchronized reserve beyond a more general demand for primary reserve, which can be satisfied by the synchronized and nonsynchronized reserve products, and for 30-minute reserve, which can be satisfied by all three reserve products. Beyond the synchronized reserve requirement, the balance of primary reserve can be made up by the economic combination of synchronized and nonsynchronized reserve. While it can be used to satisfy the 30-minute reserve requirement, as seen in Figure 10-2, nonsynchronized reserve is mainly used for satisfying the primary reserve requirement.

In the RTO Reserve Zone, in the first three months of 2026, the average amount of real-time cleared nonsynchronized reserve was 1,171.6 MW and the average day-ahead cleared nonsynchronized reserve was 1,181.5 MW. In the MAD Reserve Subzone, in the first three months of 2026, the average real-time cleared nonsynchronized reserve was 781.2 MW and the average day-ahead cleared nonsynchronized reserve was 728.8 MW.

Supply

The market solution considers the available supply of nonsynchronized reserve to be all generation resources currently not synchronized to the grid but available and capable of providing energy within 10 minutes. Generators that have made themselves unavailable or that have defined themselves to be emergency only are not considered. Resources that generally qualify as nonsynchronized reserve include run of river hydro, pumped hydro, and combustion turbines and RICE generators that can start in 10 minutes or less.

The available reserve MW for nonsynchronized reserve units is the lesser of the economic maximum or the ramp rate times 10 minutes minus the startup and notification time. Hydroelectric resources must separately specify their availability and offer MW.

In the first three months of 2026, an average of 1,171.6 MW of nonsynchronized reserve was cleared per five-minute interval out of an average eligible and available 1,193.2 MW as part of the primary reserve requirement in the RTO Reserve Zone. Figure 10-24 shows daily average total nonsynchronized reserve MW available in the first three months of 2026. Available nonsynchronized reserve decreased on January 25 and January 26 during a cold weather event which included Winter Storm Fern, for which PJM increased online generation.

Figure 10-24 Daily Average Available Nonsynchronized Reserve: January through March, 2026

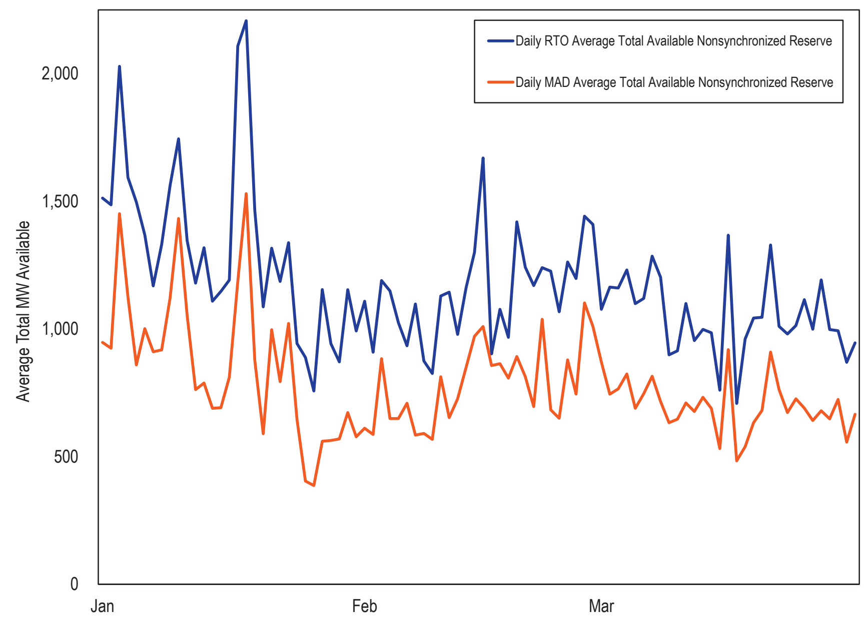
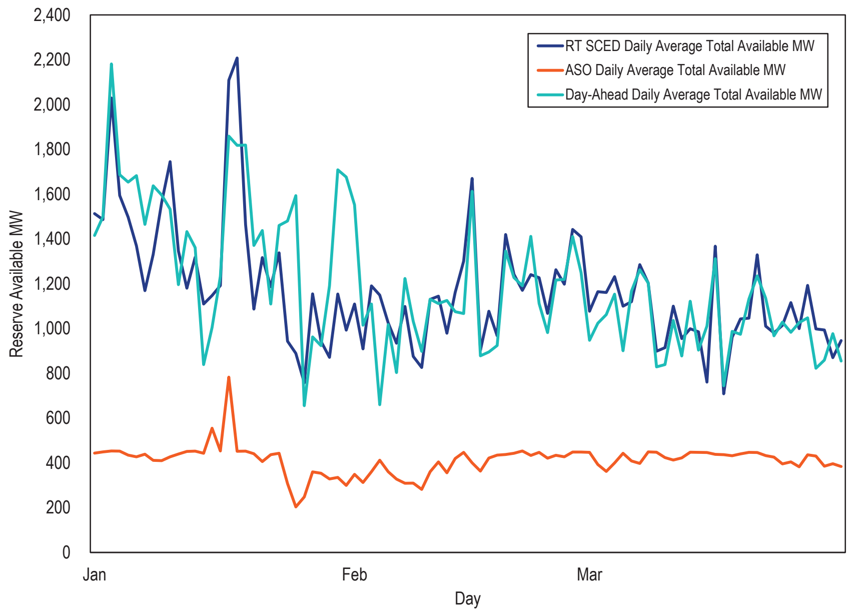


Figure 10-25 shows the daily average total available NSR MW in the ASO, RT SCED, and day-ahead solutions. The available MW in the ASO are consistently lower due to differences in the available MW from flexible units based on the goal of the ASO. For example, a unit could be projected to be online by the ASO but actually be offline in real time.

Figure 10-25 Daily average total available MW in the day-ahead, ASO, and RT SCED solutions: January through March, 2026



Market Behavior

The offer price for nonsynchronized reserve for all resources is cost based, which is $0 per MWh for all nonsynchronized resources.

Market Performance

The settled price of nonsynchronized reserve is calculated in real time every five minutes for the RTO Reserve Zone and the MAD Reserve Subzone. Figure 10-26 shows the daily average nonsynchronized reserve market clearing price (NSRMCP) and average credited MW for the RTO Reserve Zone. In the first three months of 2026, the real-time weighted average NSRMCP for all intervals in the RTO Reserve Zone was $2.34 per MWh and the real-time average nonsynchronized reserve cleared was 1,171.6 MW. The day-ahead weighted average NSRMCP for all intervals in the RTO Reserve Zone was $1.96 per MWh and the day-ahead average nonsynchronized reserve cleared MW was 1,181.5 MW. The real-time weighted average NSRMCP for all intervals in the MAD Reserve Subzone was $2.94 per MWh and the real-time average nonsynchronized reserve cleared was 781.2 MW. The day-ahead weighted average NSRMCP for all intervals in the MAD Reserve Subzone was $1.48 per MWh and the day-ahead average nonsynchronized reserve cleared MW was 728.8 MW.

In the first three months of 2026, shortage pricing was used in the RTO Reserve Zone for primary reserve on January 24 and 31; February 2, 6, 9, 13, and 16; and March 1, 12, 13, and 22. In the first three months of 2026, shortage pricing was used in the MAD Reserve Subzone for primary reserve on January 24; February 9; and March 1, 12, and 13. The shortage pricing on March 1, 2026, overlapped with synchronized reserve events. Conservative operations due to cold weather were in place from January 24 through February 2, 2026. Cold weather alerts were issued for January 19, 20, 23, and 24 through 31 and for February 1, 2, 7, 8, and 9. During most of these short intervals, there was not a true shortage, as PJM still cleared above the average reserve requirements used before PJM's mid-May 2023 increase.

Figure 10-26 Daily weighted average RTO Zone nonsynchronized reserve market clearing price, average MW purchased, and average percent of PR that is NSR: January 2025 through March 2026

Table 10-26 shows the number of five-minute intervals with an NSRMCP above $0 per MWh. The NSRMCP is equal to the cost of the marginal primary reserve resource.[99] While the offer price of NSR resources is cost based and therefore $0 per MWh, if the marginal resource of primary reserve in an interval is an SR resource with a nonzero cost, then the NSRMCP in that interval will also be nonzero. While the real-time market clears resources in five-minute intervals, the day-ahead market clears by hour, equivalent to blocks of 12 five-minute intervals. Table10-26 compares the two markets

99 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.4.5.2 Determination of Non-Synchronized Reserve Clearing Prices, Rev. 136 (Oct. 1, 2025).

using five-minute intervals. There were 25,908 five-minute intervals in the first three months of 2026.

Table 10-26 Number of five minute intervals with NSRMCP above $0 per MWh: January through March, 2026

Location	Market	Number of Intervals Where NSRMCP Above $0 per MWh	Percent of Intervals Where NSRMCP Above $0 per MWh
RTO	RT	6,910	26.7%
RTO	DA	11,556	44.6%
MAD	RT	6,911	26.7%
MAD	DA	12,636	48.8%

Figure 10-27 shows the number of intervals per day for which a nonzero NSRMCP equaled the SRMCP. Since the increase to the reserve requirement on May 12, 2023, the average number of such intervals per day has increased, with the maximum number and given number of such intervals per day both trending upwards. In the first three months of 2026, the number of such intervals differed for the RTO Reserve Zone and the MAD Reserve Subzone from January 4 through January 5. Table10-27 shows the intervals for which a nonzero NSRMCP did not equal the SRMCP. Generally, when the marginal primary resource is a synchronized resource, then the NSRMCP equals the SRMCP. However, when shortage pricing is used, the two can differ, due to the NSRMCP being capped at $1,275 per MWh (1.5 times the $850 penalty factor) while the SRMCP is capped at $1,700 (twice the $850 penalty factor). Higher prices are seen in Figure 10-27 and Table10-27 on December 14 and December 15 during a cold weather event for which PJM issued cold weather alerts.

Figure 10-27 Number of intervals per day for which a nonzero NSRMCP equaled the SRMCP: January 2025 through March 2026

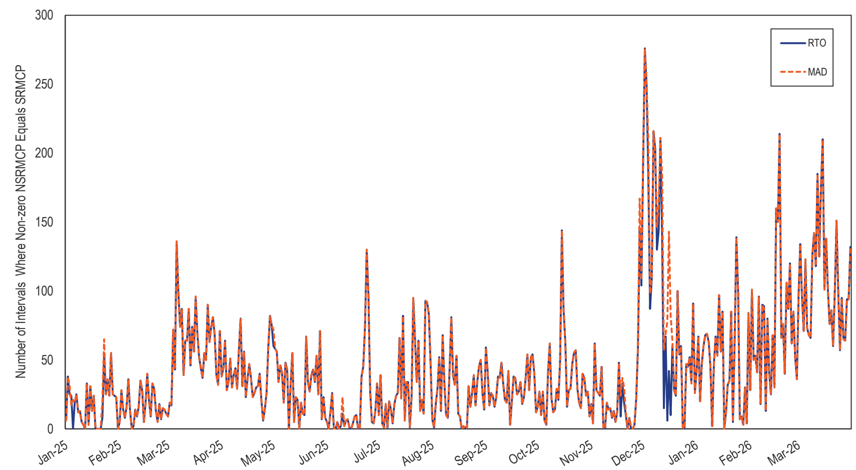


Table 10-27 Intervals with a nonzero NSRMCP in which the NSRMCP did not equal the SRMCP: January through March, 2026

	RTO		MAD	
Interval	NSRMCP	SRMCP	NSRMCP	SRMCP
24-Jan-2026 0535 (EPT)	$850.00	$1,150.00	$850.00	$1,150.00
24-Jan-2026 0540 (EPT)	$850.00	$1,700.00	$1,150.00	$1,700.00
25-Jan-2026 0140 (EPT)	$0.00	$0.00	$74.04	$115.02
09-Feb-2026 0720 (EPT)	$850.00	$1,030.34	$1,275.00	$1,700.00
09-Feb-2026 0725 (EPT)	$850.00	$850.00	$1,275.00	$1,700.00
09-Feb-2026 0730 (EPT)	$850.00	$850.00	$1,275.00	$1,700.00
01-Mar-2026 1930 (EPT)	$850.00	$1,700.00	$1,275.00	$1,700.00
01-Mar-2026 1935 (EPT)	$850.00	$1,700.00	$1,275.00	$1,700.00
12-Mar-2026 1855 (EPT)	$850.00	$1,700.00	$850.00	$1,700.00
12-Mar-2026 1900 (EPT)	$850.00	$1,700.00	$850.00	$1,700.00
12-Mar-2026 1905 (EPT)	$850.00	$1,150.00	$1,150.00	$1,450.00
12-Mar-2026 1910 (EPT)	$850.00	$1,700.00	$1,275.00	$1,700.00
13-Mar-2026 0710 (EPT)	$850.00	$1,150.00	$1,150.00	$1,450.00
13-Mar-2026 0715 (EPT)	$850.00	$1,700.00	$1,275.00	$1,700.00
13-Mar-2026 0720 (EPT)	$850.00	$1,700.00	$1,275.00	$1,700.00
13-Mar-2026 0725 (EPT)	$850.00	$1,700.00	$1,275.00	$1,700.00

Table 10-28 shows the effect of fast start pricing on the nonsynchronized reserve market's monthly weighted average market clearing price for January 2025 through March 2026. Fast start pricing increases LMP in the pricing run relative to the dispatch run, which increases reserve prices. Fast start pricing also reduces the amount of reserves available in the pricing run compared to the dispatch run, by pretending that fast start units can be dispatched for energy below their economic minimum output limit but not counting MW below the economic minimum output limit as reserves. For the real-time market, these are the LPC prices weighted by the RT SCED MW. For the day-ahead values, these are the DA prices weighted by the DA dispatch MW. The weighted average market clearing price for each month tends to be higher in the pricing run than in the dispatch run. In the first three months of 2026, the real-time RTO weighted average price of the pricing run was 23.6 percent higher than that of the dispatch run. In the first three months of 2026, the day-ahead RTO weighted average price of the pricing run was 1.4 percent lower than that of the dispatch run. In the first three months of 2026, the real-time MAD weighted average price of the pricing run was 21.4 percent higher than that of the dispatch run. In the first three months of 2026, the day-ahead MAD weighted average price of the pricing run was 2.8 percent higher than that of the dispatch run.

Table 10-28 Comparison of fast start and dispatch RTO pricing: January 2025 through March 2026

		Day-Ahead				Real-Time			
Year	Month	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference
2025	Jan	$1.23	$1.30	$0.07	6.1%	$0.70	$0.92	$0.22	31.7%
2025	Feb	$0.59	$0.59	($0.00)	(0.7%)	$0.51	$0.79	$0.28	54.2%
2025	Mar	$3.27	$3.00	($0.26)	(8.1%)	$2.20	$3.41	$1.21	55.1%
2025	Apr	$3.56	$3.41	($0.15)	(4.2%)	$0.93	$1.85	$0.92	99.5%
2025	May	$1.89	$1.77	($0.12)	(6.4%)	$1.11	$1.55	$0.44	39.8%
2025	Jun	$3.74	$3.47	($0.27)	(7.1%)	$3.31	$4.10	$0.79	23.8%
2025	Jul	$6.12	$5.56	($0.56)	(9.2%)	$1.81	$2.66	$0.85	47.2%
2025	Aug	$1.89	$1.59	($0.30)	(15.8%)	$0.78	$1.10	$0.33	42.3%
2025	Sep	$2.52	$1.92	($0.60)	(23.7%)	$1.36	$1.70	$0.34	25.1%
2025	Oct	$3.65	$3.66	$0.02	0.5%	$1.67	$2.33	$0.66	39.5%
2025	Nov	$1.84	$1.35	($0.49)	(26.6%)	$0.58	$0.86	$0.28	48.4%
2025	Dec	$1.15	$0.91	($0.25)	(21.4%)	$0.84	$1.17	$0.33	39.2%
2025	All	$2.41	$2.18	($0.23)	(9.6%)	$1.23	$1.75	$0.52	42.0%
2026	Jan	$2.15	$2.18	$0.03	1.6%	$1.56	$2.09	$0.53	34.4%
2026	Feb	$0.73	$0.53	($0.20)	(27.4%)	$1.56	$1.92	$0.36	23.0%
2026	Mar	$2.67	$2.73	$0.06	2.2%	$2.55	$2.95	$0.40	15.7%
2026	All	$1.88	$1.86	($0.03)	(1.4%)	$1.86	$2.30	$0.44	23.6%

Table 10-29 Comparison of fast start and dispatch MAD pricing: January 2025 through March 2026

		Day-Ahead				Real-Time			
Year	Month	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference
2025	Jan	$1.09	$1.14	$0.05	4.9%	$1.01	$1.25	$0.23	22.9%
2025	Feb	$1.24	$1.23	($0.01)	(1.1%)	$0.60	$0.94	$0.34	56.1%
2025	Mar	$4.53	$4.21	($0.33)	(7.2%)	$2.71	$4.14	$1.43	52.9%
2025	Apr	$6.57	$6.38	($0.19)	(3.0%)	$1.30	$2.37	$1.07	81.8%
2025	May	$4.13	$3.87	($0.26)	(6.4%)	$1.42	$2.04	$0.61	43.1%
2025	Jun	$7.22	$6.76	($0.46)	(6.4%)	$4.28	$4.91	$0.62	14.5%
2025	Jul	$10.23	$9.40	($0.83)	(8.1%)	$1.88	$2.80	$0.92	49.2%
2025	Aug	$3.34	$2.82	($0.52)	(15.5%)	$0.82	$1.25	$0.44	53.3%
2025	Sep	$2.74	$2.22	($0.52)	(19.0%)	$1.60	$1.96	$0.36	22.5%
2025	Oct	$4.30	$4.27	($0.03)	(0.7%)	$1.95	$2.66	$0.71	36.4%
2025	Nov	$3.23	$3.32	$0.09	2.7%	$1.14	$1.54	$0.40	34.7%
2025	Dec	$3.20	$3.25	$0.04	1.4%	$2.76	$3.33	$0.57	20.7%
2025	All	$3.66	$3.47	($0.20)	(5.3%)	$1.73	$2.33	$0.60	35.0%
2026	Jan	$0.95	$0.98	$0.03	3.3%	$2.22	$2.98	$0.76	34.0%
2026	Feb	$0.93	$0.98	$0.04	4.7%	$2.17	$2.61	$0.45	20.6%
2026	Mar	$2.78	$2.83	$0.05	1.9%	$3.06	$3.38	$0.32	10.5%
2026	All	$1.44	$1.48	$0.04	2.8%	$2.46	$2.99	$0.53	21.4%

In the first three months of 2026, in the RTO Reserve Zone, the real-time weighted average price of nonsynchronized reserve was $2.34 per MWh and the real-time weighted average sum of the MCP credits and LOC credits for nonsynchronized reserve was $0.89 per MWh. In the first three months of 2026, in the MAD Reserve Subzone, the real-time weighted average price of nonsynchronized reserve was $2.94 per MWh and the real-time weighted average sum of the MCP credits and LOC credits for nonsynchronized reserve was $0.28 per MWh.

Table 10-30 shows the total nonsynchronized reserve payments by month from January 2025 through March 2026. In January and February 2026, shortage pricing for primary reserve in the RTO was used for 34 intervals during a cold weather event. Figure 10-26 shows the resulting spike in prices. Due to units buying back portions of their day-ahead schedule at these high real-time prices, the sum of the real-time and balancing MCP credits seen in Table 10-30 for January 2026 is significantly negative.

Table 10-30 Total nonsynchronized reserve payments and charges by month: January 2025 through March 2026

Year	Month	Day-Ahead Credits	Real-Time and Balancing MCP Credits	LOC Credits	Shortfall Charges	Total Credits
2025	Jan	$1,310,758	($807,014)	$185,652	NA	$689,396
2025	Feb	$698,931	($300,892)	$96,940	NA	$494,978
2025	Mar	$2,079,574	($470,698)	$289,300	NA	$1,898,176
2025	Apr	$1,984,502	($247,956)	$91,497	NA	$1,828,043
2025	May	$1,340,915	($151,404)	$64,475	NA	$1,253,986
2025	Jun	$2,457,199	($2,282,555)	$102,702	NA	$277,346
2025	Jul	$3,413,482	($958,506)	$121,292	NA	$2,576,268
2025	Aug	$1,266,236	($425,994)	$67,415	NA	$907,657
2025	Sep	$1,261,458	($285,138)	$163,072	NA	$1,139,392
2025	Oct	$1,708,180	$132,342	$61,983	NA	$1,902,505
2025	Nov	$1,411,665	($216,606)	$84,484	NA	$1,279,542
2025	Dec	$1,658,885	($113,519)	$184,463	NA	$1,729,828
2025	All	$20,591,785	($6,127,942)	$1,513,273	NA	$15,977,117
2026	Jan	$2,369,695	($2,011,682)	$97,621	NA	$455,634
2026	Feb	$585,493	($640,427)	$104,604	NA	$49,670
2026	Mar	$2,041,630	($394,677)	$87,783	NA	$1,734,736
2026	All	$4,996,817	($3,046,786)	$290,009	NA	$2,240,040

Table 10-31 provides the day-ahead and real-time nonsynchronized reserve by primary resource type and fuel type for the first three months of 2026. Much of the negative balancing MCP credits applied to hydro resources occurred during Winter Storm Fern in January.

Table 10-31 Day-ahead and real-time nonsynchronized reserve by primary resource type and fuel type: January through March, 2026

Resource / Fuel Type	Day-Ahead MWh	Real-Time Scheduled MWh	Day-Ahead Credits	Balancing MCP Credits	LOC Credits	Total Credits
Oil	2,861,560	2,780,215	$14,245,479	($1,905,518)	$161,980	$12,501,941
Hydro	4,955,596	4,723,905	$4,685,853	($3,695,135)	$1,242,490	$2,233,207
RICE - Natural Gas	806,538	665,432	$1,434,452	($401,574)	$93,220	$1,126,099
Other	62,407	40,564	$226,002	($31,870)	$3,060	$197,193

30-Minute Reserve

The 30-minute reserve service is provided by resources that can respond in 30 minutes. The requirement for the 30-minute reserve service can be satisfied by the synchronized reserve product, the nonsynchronized reserve product, and the secondary reserve product. There is no NERC standard for 30-minute reserve.

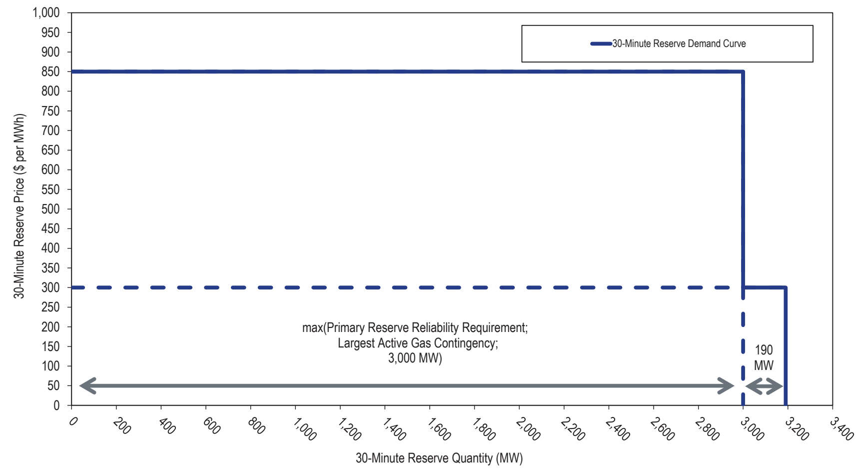
Market Structure

Demand

Demand for the 30-minute reserve service comes from the 30-minute reserve requirement. By default, the 30-minute reserve requirement is equal to the extended reserve requirement plus the 30-minute reserve reliability requirement. 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.[100] Unlike with synchronized reserve and primary reserve, PJM does not model a 30-minute reserve requirement for the defined reserve subzone.[101] However, PJM has the option to define a subzone natural gas contingency reserve requirement using 30-minute reserves. PJM did not exercise this option in the first three months of 2026.

Figure 10-28 shows an example ORDC for 30-minute reserve for when the primary reserve reliability requirement and the largest active gas contingency are both less than 3,000 MW, and when the extended reserve requirement is equal to its base value of 190 MW. Since the increase to the synchronized reserve reliability requirement in May 2023, the 30-minute reserve requirement has frequently equaled the primary reserve requirement.

Figure 10-28 An example of a 30-minute reserve real-time operating reserve demand curve, including the permanent second step



In the first three months of 2026, the real-time average 30-minute requirement was 3,453.2 MW and the day-ahead average 30-minute requirement was 3,452.3 MW (Figure 10-4).

100 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.3 Reserve Requirement Determination, Rev. 136 (Oct. 1, 2025).
101 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.3.1 Locational Aspect of Reserves, Rev. 136 (Oct. 1, 2025).

Supply

The supply of 30-minute reserves includes all reserves that can convert to energy in 30 minutes. All reserve products can participate in the 30-minute reserve service. In the first three months of 2026, the demand for 30-minute reserve was satisfied by primary reserves (made of synchronized reserves and nonsynchronized reserves) and secondary reserves. The 30-minute reserve requirement is met from the least expensive combination of synchronized, nonsynchronized, and secondary reserves that satisfies the requirements of the synchronized, primary, and 30-minute reserve services (Table 10-9).

Market Concentration

Table 10-32 shows the average HHI of the 30-minute reserve market, including synchronized, nonsynchronized, and secondary reserves, and the percent of intervals for which the maximum market share is above 20 percent. In the first three months of 2026, the RTO Reserve Zone was unconcentrated in the day-ahead market and unconcentrated in the real-time market.

Table 10-32 PJM 30-minute reserve market HHI: January through March, 2026

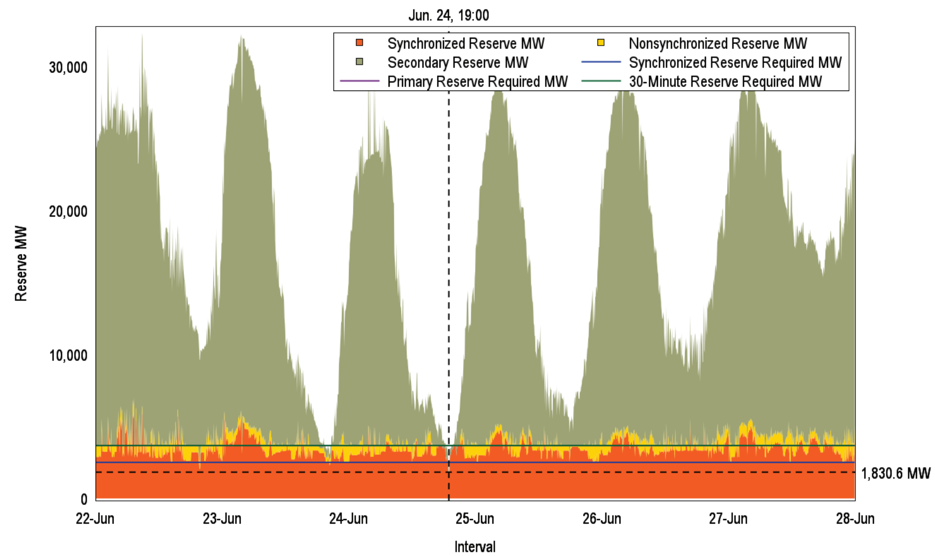
Location	Market	Average HHI	Percent of Intervals Max Market Share Above 20%	Description
RTO	RT	748	13.6%	Unconcentrated
RTO	DA	841	26.4%	Unconcentrated

Market Performance

Due to the large amount of available secondary reserve, most 30-minute reserve is procured at low cost, with the amount of cleared secondary reserve far exceeding what is strictly needed to satisfy the 30-minute reserve requirement (Figure 10-2). In the first three months of 2026, there were no intervals short of 30-minute reserve.

However, 30-minute reserves were short in 23 intervals from June 23, 2025, through June 24, 2025, during a hot weather event. Figure 10-29 shows the point during the hot weather event when cleared 30-minute reserves were at their lowest. For that interval, the amount of 30-minute reserve offered was 5,954.9 MW. This was larger than the 30-minute requirement of 3,677.6 MW.

Figure 10-29 30-minute reserve shortage during the June 2025 hot weather event: June 22 through June 27, 2025



Secondary Reserve

PJM defines secondary reserve as reserves (online or offline available for dispatch) that can be converted to energy in 10 to 30 minutes. There is no NERC standard for secondary reserve. The secondary reserve product can only be used to satisfy the 30-minute reserve requirement, and is cleared for five-minute intervals in the real-time market and hourly intervals in the day-ahead market. Failure to convert offline secondary reserves to energy at PJM's request results in a shortfall charge.

Unlike synchronized reserve and nonsynchronized reserve, there is no "event" process to deploy secondary reserve. Instead, PJM uses secondary reserve via the normal energy commitment and dispatch process.

Market Structure

Demand

There is no explicit demand for secondary reserve beyond a more general demand for 30-minute reserve, which can be satisfied by the synchronized, nonsynchronized, and secondary reserve products. Beyond the primary reserve requirement, the balance of 30-minute reserve can be made up by the economic combination of synchronized, nonsynchronized, and secondary reserve.

When the secondary reserve market clearing price is $0 per MWh, PJM's clearing engines clear all available secondary reserve MW. Because of the large amount of secondary reserve cleared, most 30-minute reserve is secondary reserve and most cleared secondary reserve is cleared well in excess of the 30-minute reserve requirement (Figure 10-2).

Supply

Secondary reserves are reserves that can convert to energy within 10 to 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. It also includes offline resources that offer a time to start of less than 30 minutes but more than 10 minutes. Secondary reserves do not include pre-emergency or emergency demand response resources, even if they offer to start in less than 30 minutes. Secondary reserves do not include exports that can be recalled in less than 30 minutes.

As with the other reserve products, for most resources, PJM determines the MW available for secondary reserve based on energy offer parameters.[102] Energy Storage Resource model participants, hydroelectric resources, and demand response resources must specify their availability and MW separately.

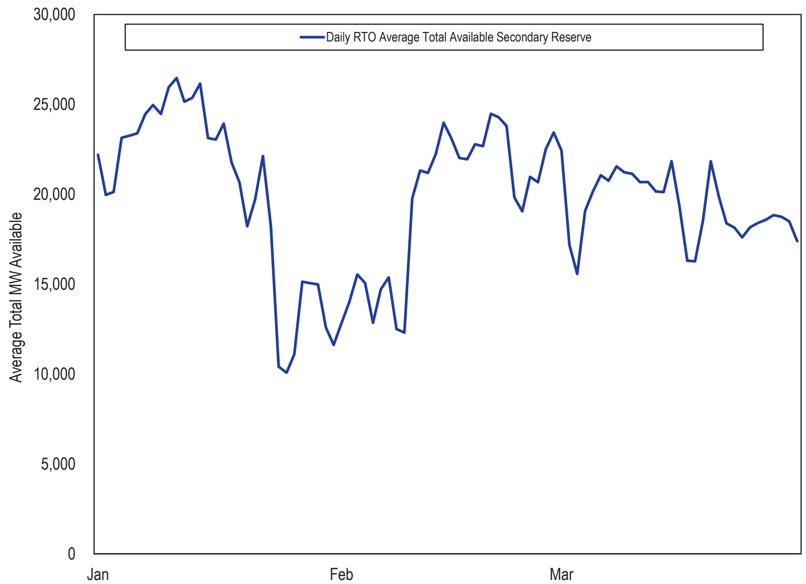
102 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.2.3 Reserve Market Resource Offer Structure, Rev. 136 (Oct. 1, 2025).

Online resources' secondary reserves are based on ramp rates and the lesser of the secondary reserve maximum or economic maximum parameters, as well as any cleared synchronized reserve.[103] The use of the secondary reserve maximum output limit requires prior approval by PJM.[104] Offline resources' secondary reserves are based on the time to start, which is the start-up time plus notification time, and any cleared nonsynchronized reserve.[105] Certain resource types, including nuclear, wind, and solar units, are by default excluded from providing secondary reserves.

Figure 10-30 shows the daily average total available secondary reserve in the first three months of 2026. In the first three months of 2026, the real-time average supply of secondary reserve was 20,180.6 MW and the day-ahead average supply was 12,307.3 MW. The available secondary reserve decreased in January and February during a cold weather event which included Winter Storm Fern (Figure 10-28) as PJM brought on more units for energy.

103 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.2.5.1 Reserve Market Capability for Online Generation Resources, Rev. 136 (Oct. 1, 2025).
104 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.2.2.1 Communication for Reserve Capability Limitation, Rev. 136 (Oct. 1, 2025).
105 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.2.5.2 Reserve Market Capability for Offline Generation Resources, Rev. 136 (Oct. 1, 2025).

Figure 10-30 Daily Average Available Secondary Reserve: January through March, 2026



Market Behavior

For all resources, the secondary reserve offer price is $0 per MWh.[106] For online resources, the energy market opportunity cost is calculated by PJM based on market prices.

Market Performance

Figure 10-31 shows the unweighted average market clearing prices for secondary reserves in the first three months of 2026. Due to the product's low cost and ample supply, the secondary reserve market clearing price (SecRMCP) is almost always $0 per MWh. In the first three months of 2026, the real-time SecRMCP was nonzero for zero five-minute intervals and the day-ahead SecRMCP was nonzero for zero hours.

106 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.2.3 Reserve Market Resource Offer Structure, Rev. 136 (Oct. 1, 2025).

Figure 10-31 Secondary reserve prices: January through March, 2026

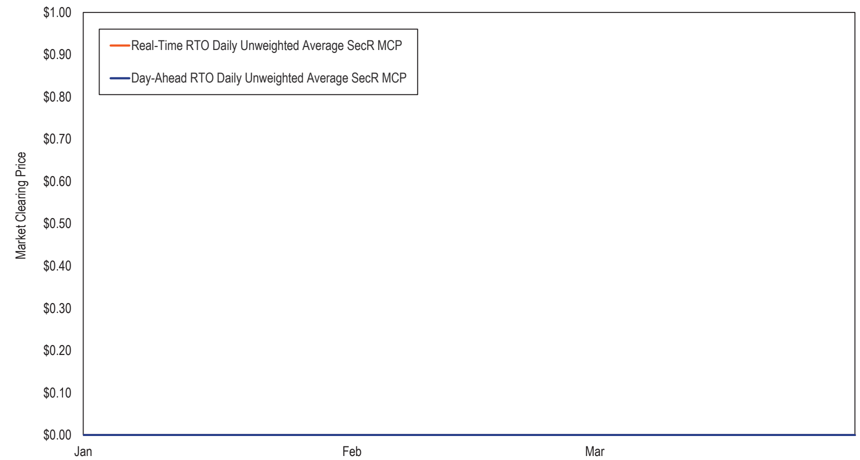


Table 10-33 compares the dispatch run and pricing run market clearing prices for the day-ahead and real-time secondary reserve markets. For both the dispatch run and the pricing run, the real-time values are the LPC prices for each run weighted by the RT SCED MW. For the day-ahead values, these are the day-ahead prices weighted by the day-ahead dispatch MW. In the first three months of 2026, the day-ahead SecRMCPs were $0 per MWh for all hours in both the pricing run and the dispatch run. In real time, the SecRMCPs for the pricing run and dispatch run were $0 per MWh for all intervals.

Table 10-33 Comparison of fast start and dispatch pricing components: January 2025 through March 2026

		Day-Ahead				Real-Time			
Year	Month	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference
2025	Jan	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2025	Feb	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2025	Mar	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2025	Apr	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2025	May	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2025	Jun	$0.00	$0.00	$0.00	NA	$0.05	$0.05	$0.00	0.0%
2025	Jul	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2025	Aug	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2025	Sep	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2025	Oct	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2025	Nov	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2025	Dec	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2025	All	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	0.0%
2026	Jan	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2026	Feb	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2026	Mar	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2026	All	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA

Table 10-34 shows the day-ahead credits, balancing market credits, LOC credits, and effective shortfall charges for secondary reserves from January 2025 through March 2026.[107] In the first three months of 2026, the real-time weighted average secondary reserve market clearing price was $0.00 per MWh and the day-ahead weighted average secondary reserve market clearing price was $0.00 per MWh. In the first three months of 2026, the real-time weighted average credit per MWh, considering the total credits paid and the capped MWh, was $0.12 per MWh and the day-ahead weighted average credit was $0.00 per MWh. In June 2025, balancing credits were negative during a hot weather event that saw 30-minute reserve shortage, causing shortage pricing for secondary reserve.

107 Unlike synchronized reserve, for secondary reserve, shortfall is accounted for in the balancing MCP credits and is not a separate item. The effective shortfall charge is the real-time SecR MCP multiplied by the shortfall MW, a value used when calculating the balancing MCP credits.

Table 10-34 Monthly secondary reserve settlements: January 2025 through March 2026

Year	Month	Total Day-Ahead Credits	Total Balancing MCP Credits	Total LOC Credits	Total Effective Shortfall Charge	Total Credits
2025	Jan	$0	$0	$243,258	$0	$243,258
2025	Feb	$0	$0	$133,463	$0	$133,463
2025	Mar	$0	$0	$126,843	$0	$126,843
2025	Apr	$0	$0	$135,333	$0	$135,333
2025	May	$0	$0	$420,010	$0	$420,010
2025	Jun	$0	($986,243)	$1,825,703	$0	$839,460
2025	Jul	$0	$0	$1,274,869	$0	$1,274,869
2025	Aug	$0	$0	$1,150,153	$0	$1,150,153
2025	Sep	$0	$0	$850,339	$0	$850,339
2025	Oct	$0	$0	$927,503	$0	$927,503
2025	Nov	$0	$0	$682,979	$0	$682,979
2025	Dec	$0	$0	$1,540,616	$0	$1,540,616
2025	All	$0	($986,243)	$9,311,069	$0	$8,324,826
2026	Jan	$0	$0	$1,669,975	$0	$1,669,975
2026	Feb	$0	$0	$1,833,828	$0	$1,833,828
2026	Mar	$0	$0	$990,352	$0	$990,352
2026	All	$0	$0	$4,494,155	$0	$4,494,155

Table 10-35 provides secondary reserve credits by primary resource and fuel type for the first three months of 2026.

Table 10-35 Secondary reserve credits by primary resource and fuel type: January through March, 2026

Resource / Fuel Type	Day-Ahead MWh	Real-Time Capped MWh	Day-Ahead Credits	Balancing MCP Credits	LOC Credits	Total Credits
Combined Cycle	462	2,554,867	$0	$0	$1,531,645	$1,531,645
Steam - Coal	0	2,156,824	$0	$0	$1,315,799	$1,315,799
CT - Natural Gas	20,017,248	27,861,440	$0	$0	$1,105,652	$1,105,652
CT - Oil	3,246,984	4,169,982	$0	$0	$174,302	$174,302
RICE - Natural Gas	12,004	68,748	$0	$0	$139,141	$139,141
Steam - Natural Gas	0	264,152	$0	$0	$126,553	$126,553
Steam - Other	0	37,013	$0	$0	$96,050	$96,050
RICE - Oil	162,231	199,653	$0	$0	$5,012	$5,012
Hydro - Pumped Storage	36,950	779,514	$0	$0	$0	$0
Other	5,724	106,059	$0	$0	$0	$0

Among other reasons, a secondary reserve resource is paid an LOC credit when PJM determines that the resource was backed down in order to clear more secondary reserve. Because the supply of secondary reserves greatly exceeds the amount needed to meet the 30-minute reserve requirement, PJM does not actually back down resources to clear more secondary reserve. However, because of the method used by PJM to determine whether a resource was backed down, PJM at times pays resources for an incorrectly determined real-time opportunity cost. For example, PJM erroneously treated resources coming online to provide energy as having been backed down to provide secondary reserves. PJM does not back down resources below their economic minimum to provide secondary reserves, but in the first three months of 2026, for secondary reserve resources that did not clear day-ahead and were generating below their economic minimum points, PJM paid $1,122,586 in LOC credits.

Regulation Market

Regulation matches generation with short term changes in load by moving the output of selected resources up and down via an automatic control signal. Regulation is provided by generators with a short-term response capability (less than five minutes) or by demand response (DR). The PJM Regulation Market is operated as a single real-time market.

PJM filed proposed significant changes to the regulation market design with FERC on April 16, 2024.[108] The Commission Order of June 14, 2024, accepted the PJM proposal as filed. PJM will implement the changes to the regulation market in two phases.[109] Phase 1, implemented on October 1, 2025, is a single product, single signal market with one clearing price. Phase 2, to be implemented on October 1, 2026, will include separate regulation up and regulation down markets. The Phase 1 changes eliminated many of the significant issues identified by the MMU that resulted from the prior two product, two signal market design, including the incorrect and inconsistent use and application of the MBF/MRTS.[110]

108 PJM, "Regulation Market Design Filing," Docket No. ER24-1772-000.
109 See 187 FERC ¶ 61,173.
110 See Order No. 755, 137 FERC ¶ 61,064 at P 2 (2011).

This report analyzes the regulation market results from the first quarter of 2026 under the new Phase 1 regulation market design.

Market Design

The objective of PJM's regulation market design should be to minimize the cost to provide regulation. The new design, as actually implemented, does not meet that goal.

The regulation market design includes three clearing price components: capability ($/MW, based on the MW offered); performance ($/MW*mile, based on the total MW movement requested by the control signal, known as mileage); and lost opportunity cost ($/MW of lost revenue from the energy market as a result of providing regulation). The performance score translates actual MW into effective MW, and offers and clearing prices into $/effective MW.

Phase 1 of PJM's regulation market redesign was implemented on October 1, 2025. The new market design replaced two separate RegA/RegD signals/products with a single signal/product, eliminating the need for the benefit factor. The new market design includes the LOC in the market price, although there are issues with the LOC calculation. The new market design simplifies the performance score calculation.

Market solution software relevant to regulation consists of the Ancillary Services Optimizer (ASO) solving each half hour; the intermediate term security constrained economic dispatch market solution (IT SCED) solving every 15 minutes; and the real-time security constrained economic dispatch market solution (RT SCED) solving every five minutes. The ASO, incorporating the forecast LMP values in the LOC calculation, defines the cleared regulation MW. The regulation market clearing price is a function of the defined demand for regulation and the offer prices that incorporate LOC based on real-time LMP based on the most recently approved RT SCED case, approximately 10 minutes ahead of the target solution time. The regulation market clears based on the resultant offer prices over 30 minute periods.

The current design includes new definitions of regulation demand. The demand for regulation is defined by the categories of ramp hours, nonramp hours, and shoulder hours. In addition, the length of the regulation seasons and the regulation requirements for each category were modified (Table10-36). The regulation requirement for ramp hours was changed from 800 effective MW to 750 effective MW, for nonramp hours was changed from 525 effective MW to 550 effective MW, and for the new shoulder hours was set to 650 effective MW. The definition of the hours for each category of ramp hours changes by season. These changes together will increase the yearly regulation effective MW demand by 3.9 percent.

Table 10-36 Seasonal regulation requirement definitions.

Season	Dates	Nonramp Hours (550 MW)	Shoulder Hours (650 MW)	Ramp Hours (750 MW)
Winter	Nov 1 - Feb 28(29)	01:00 - 03:59 11:00 - 15:59	0:00 - 0:59 10:00 - 10:59	04:00 - 09:59 16:00 - 23:59
Spring	Mar 1 - Apr 30	02:00 - 04:59 10:00 - 17:59	1:00 - 1:59 9:00 - 9:59	05:00 - 08:59 18:00 - 00:59
Summer	May 1 - Sep 15	02:00 - 03:59	1:00 - 1:59	04:00 - 00:59
Fall	Sep 16 - Oct 31	01:00 - 04:59 10:00 - 16:59	0:00 - 0:59 9:00 - 9:59	05:00 - 08:59 17:00 - 23:59

Each cleared resource is allocated a portion of the signal based on the cleared regulation MW of the resource relative to the total cleared MW of regulation. This signal is called the Total Regulation Signal (TREG) for the resource. A resource that cleared 10 MW of capability (Assigned Regulation or AREG) will be provided a percent TREG signal asking for a positive or negative regulation movement between negative and positive 100 percent around its regulation set point.

Regulation performance scores (0.0 to 1.0) measure the response of a regulating resource to the assigned regulation signal every 10 seconds by measuring the precision, defined to be the difference between the regulation response and the regulation requested.[111] Performance scores are reported on a half hour basis for each resource.

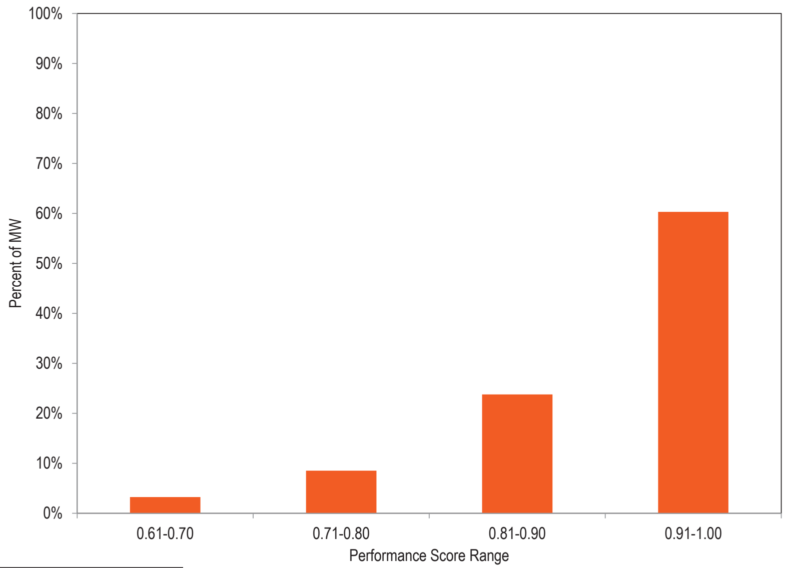
111 PJM "Manual 12: Balancing Operations," § 4.5.6 Performance Score Calculation, Rev. 54 (July Dec. 17, 2024).

Table 10-37 and Figure 10-32 show the average half hour performance score by resource type in the first three months of 2026.[112] Each category is based on the percentage of the full performance score distribution for each resource type.[113] In the first three months of 2026, 60.3 percent of all regulation resources had average performance scores within the 0.91-1.00 range.

Table 10-37 Half hour average performance score by unit type: January through March, 2026

	Performance Score Range			
Unit Type	61-70	71-80	81-90	91-100
Battery	1.2%	2.0%	5.7%	88.5%
CT	2.8%	9.1%	32.6%	51.6%
Diesel	0.9%	2.7%	18.8%	75.7%
DSR	2.3%	2.8%	4.3%	84.3%
Hydro	2.4%	7.2%	29.7%	58.2%
Steam	5.1%	14.1%	34.5%	40.9%

Figure 10-32 Half hour average performance score: January through March, 2026

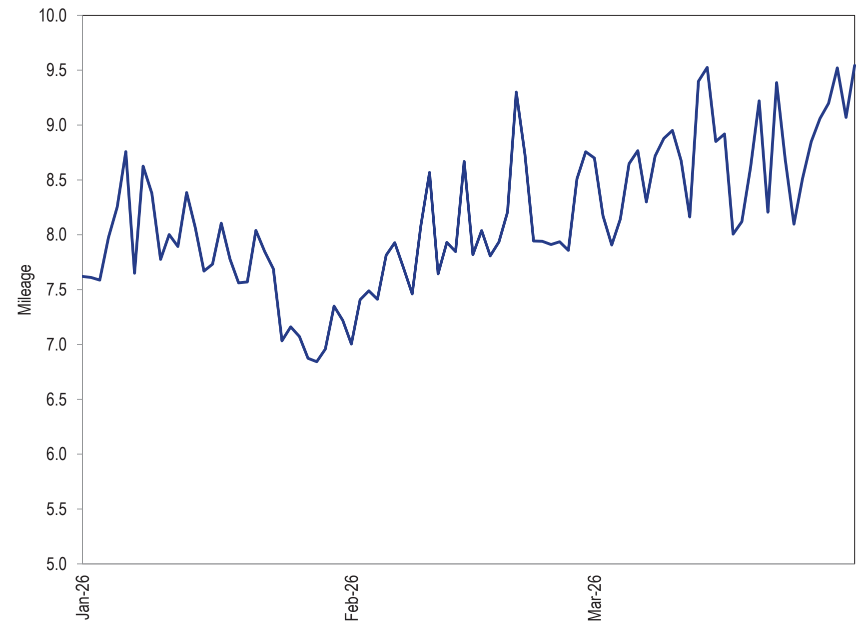


112 Except where explicitly referred to as effective MW or effective regulation MW, MW means actual MW unadjusted for performance score.
113 PJM "Manual 12: Balancing Operations," § 4.5.6 Performance Score Calculation, Rev. 54 (July Dec. 17, 2024).

The October 1, 2025, redesign eliminated the marginal benefit factor, and changed the definition of the mileage ratio. The mileage ratio is defined as the actual mileage divided by the 100 hour historical average mileage. The new design uses this mileage ratio to calculate the regulation mileage credits portion of settlements.

Figure 10-33 shows the daily average mileage ratio in the first three months of 2026.

Figure 10-33 Daily average mileage ratio: January through March, 2026



Market Design Issues

While the new market design corrected a number of issues with the old design, new issues have been identified in the new design.

The performance score is incorrect. All else being held equal, the current design inappropriately calculates a lower error for units with larger MW regulation assignments than units that perform exactly the same but with a smaller regulation assignment.

Under the new regulation market design, PJM determines the five minute interval performance score by evaluating a unit's performance every 10 seconds. This performance score is determined by calculating the error in a unit's output based on the average regulation signal MW during the entire half hour clearing interval.

The numerator is the difference between the actual regulation MW and the assigned regulation MW based on the regulation signal. The denominator is calculated as the average of the unit's assigned regulation and the average of the absolute value of the regulation signal calculated over the half hour clearing interval. This has the effect of scaling each 10 second performance score based on the clearing interval average of the overall regulation signal. The MMU disagrees with this calculation method because it scales the actual response based on the average signal over the clearing interval for no apparent reason. Identical behavior of the same unit can yield different results if the overall interval average signal is different. More importantly, the inclusion of the assigned regulation MW (AREG) in the denominator results means that identical responses from units with different levels of committed regulation MW will have different performance scores. Both results are illogical.

The MMU proposes to define regulation performance using only the ratio of the unit's response to the regulation signal.

The total performance score for the clearing interval is the average of each 10 second performance score. This means that any unit providing a steady 7.5 MW to a signal calling for 10 MW would logically receive a performance score of 0.75, regardless of the assigned regulation MW of the unit. Using PJM's equation in this case would result in different performance scores for units with the same 75 percent response, based solely on the magnitude of regulation assignment. Table10-38 illustrates the variation in performance scores that result from different assigned regulation MW amounts and average interval signals under the current calculation, compared to the MMU's proposal.

Table 10-38 Performance scores under different market conditions: Current versus MMU proposed calculation

				Performance Score	
Clearing Interval Average Absolute Signal MW	Assigned Regulation MW	Regulation Output MW	Signal MW	PJM	MMU
5.0	10.0	7.5	10.0	66.7%	75.0%
	50.0	7.5	10.0	90.9%	75.0%
	100.0	7.5	10.0	95.2%	75.0%
10.0	10.0	7.5	10.0	75.0%	75.0%
	50.0	7.5	10.0	91.7%	75.0%
	100.0	7.5	10.0	95.5%	75.0%
20.0	10.0	7.5	10.0	83.3%	75.0%
	50.0	7.5	10.0	92.9%	75.0%
	100.0	7.5	10.0	95.8%	75.0%

The MMU recommends that the performance score be revised to eliminate the effect of the size of the regulation assignment and to directly calculate the performance score based on the actual performance and the requested performance.

In October 2025, PJM identified that the clearing of less than 1.0 MW for resources was a contributing factor to extremely high prices in the regulation market, particularly during reserve shortages.

As an initial workaround, PJM told participants that they could set a minimum regulation MW level in their regulation offers. In addition, PJM implemented an after the fact (after market clearing) step that replaces any fractional MW regulation assignments with a 1.0 MW regulation assignment for any units that are eligible for LOC and have a regulation capability greater than 1.0 MW. While this override reduced the LOC contributions to regulation prices, the override did not eliminate all associated high prices and is an ad hoc fix that ignores the underlying issue.

The MMU does not agree that asking participants to make inflexible regulation offers is the correct way to address the fractional MW clearing results of the current market clearing engine design. Relying on participants to make their offers less flexible to correct for an optimization issue is not efficient or reasonable. The MMU does not agree that overriding the fractional

MW assignment with a 1.0 MW assignment is a correct way to address the fractional MW clearing results of the current market clearing engine design.

The MMU recommends that the regulation market optimization be reviewed to address the logic that allows the partial clearing of inframarginal resources.

Since the implementation of the inflexible offers and the 1.0 MW override, it became clear that the very high regulation prices are a result of interactions between offer parameters (differences between the regulation range and economic range of units and differences in offered ramp and actual ramp of units) and differences between ASO forecasted LMP and actual LMP used to set LOC for cleared regulation resources.

More fundamentally, the LOC calculation is incorrect. Regulation prices and total costs were expected to increase due to the inclusion of LOC in clearing prices rather than being paid as unit specific uplift. However, prices have been higher than appropriate in some hours as a result of differences between the regulation ranges and economic ranges of units and differences in offered ramp and actual ramp of units. Offer parameters define a regulation maximum MW (RegMax) and an economic maximum MW (EcoMax). The RegMax is the upper limit on the regulation offer and the EcoMax is the upper limit on the energy offer. RegMax should equal EcoMax. For some resources, the EcoMax is incorrectly offered as greater than the RegMax. The result is to artificially increase the LOC because the LOC is defined as the revenues that could have been earned in the energy market if the unit were not providing regulation. If RegMax and EcoMax are matched, the LOC is correctly defined by matching each MW of regulation offered with a MW of energy not sold. If the EcoMax is greater than the RegMax, the LOC is incorrectly defined by a higher MW level on the energy offer than the unit's regulation offer defines as the maximum MW for which it can provide regulation. The LOC calculation is based on the incorrect assumption that the unit gives up multiple MW of energy output for every MW of regulation. That can and does lead to extremely high LOC calculations that incorrectly inflate the clearing prices in the regulation market.

Differences between ASO forecasted LMPs and real time LMPs used to set LOC for cleared regulation resources can significantly amplify the RegMax/EcoMax issue and have resulted in the extremely high regulation prices observed at times since October 1, 2025.

Table 10-39 shows three different resources (Unit 1, Unit 2 and Unit 3) with identical costs curves (each MW of output increases marginal cost by $1), the same Reg Max, but different Eco Max. Unit 1 has Eco Max equal to Reg Max (20 MW). Unit 2 has Eco Max (30 MW) greater than Reg Max (20 MW). Unit 3 has Eco Max (40 MW) greater than Reg Max (20 MW). The clearing engine (ASO) has a forecasted LMP for all three units at $15. At $15, the economic desired MW equals the regulation set point at 15 MW for all three units, the total LOC is equal to $0.00 for all three units and each resource can clear for 5 MW of regulation at an offer of $0.00 per MW of regulation. If the real time LMP is equal to $15 (no change from the ASO forecast LMP), $/MW LOC stays at $0.00 per MW of regulation provided (first result for each unit in Table 10-39). If, however, the real time LMP is $200, the calculated $/MW LOC of Unit 1 is $182.50, the calculated $/MW LOC of Unit 2 is $532.50, and the calculated $/MW LOC of Unit 3 is $862.50.

Table 10-39 Regulation LOC Examples: Eco Max Greater than or Equal to Reg Max

Unit	Energy Price	Reg MW	Reg Set Point	Economic Desired MW	Reg Max	EcoMax	Marginal Cost at Reg Set Point	MC at Economic Desired	LOC $/MW	Total LOC
Unit 1	$15.00	5	15	15	20	20	$15.00	$15.00	$0.00	$0.00
Unit 1	$20.00	5	15	20	20	20	$15.00	$20.00	$2.50	$12.50
Unit 1	$25.00	5	15	20	20	20	$15.00	$20.00	$7.50	$37.50
Unit 1	$200.00	5	15	20	20	20	$15.00	$20.00	$182.50	$912.50
Unit 2	$15.00	5	15	15	20	30	$15.00	$15.00	$0.00	$0.00
Unit 2	$20.00	5	15	20	20	30	$15.00	$20.00	$2.50	$12.50
Unit 2	$25.00	5	15	25	20	30	$15.00	$25.00	$10.00	$50.00
Unit 2	$200.00	5	15	30	20	30	$15.00	$30.00	$532.50	$2,662.50
Unit 3	$15.00	5	15	15	20	40	$15.00	$15.00	$0.00	$0.00
Unit 3	$20.00	5	15	20	20	40	$15.00	$20.00	$2.50	$12.50
Unit 3	$25.00	5	15	25	20	40	$15.00	$25.00	$10.00	$50.00
Unit 3	$200.00	5	15	40	20	40	$15.00	$40.00	$862.50	$4,312.50

In evaluating the available supply for an interval, the clearing engine can clear less than the entire offer of a unit and can also clear less than 1.0 MW of a unit's offer. When the economic max of the unit is higher than the regulation max of the unit, clearing less than 1.0 of regulation can generate an extreme version of the problem shown in Table 10-39 above. Even after replacing the fractional MW with 1.0 MW, the market results when EcoMax is greater than regMax can be extreme.

The MMU recommends that if a unit sets its economic maximum at a value greater than its regulation maximum, the lost opportunity cost (LOC) of the unit should be calculated assuming the economic maximum of the unit is equal to the regulation maximum of the unit. The MMU recommends that, in cases where offered ramp is greater than actual ramp, the actual ramp be used to calculate the LOC of the unit. The MMU recommends that these fixes to the LOC logic be implemented prior to implementing Phase 2 of the regulation market design.

Market Redesign Phase 2

PJM is planning to introduce implement its Phase 2 regulation market design in October 2026, as approved by FERC. [114] In PJM's Phase 2 design, the regulation market will once again be split into two products with two separate prices: one product that only needs to respond when the regulation signal is above zero (RegUp), and one product that only needs to respond when the regulation signal is below zero (RegDown). In Phase 2, market resources will be able to clear as RegUp, RegDown or both in any given 30 minute market interval. PJM has not done any systematic testing of the proposal. PJM has not explained what problem this design change is intended to fix, analyzed what impact this design would have on reliability, or how this will affect the cost of regulation. The MMU continues to recommend a single product market with a single signal. Phase 1 with the issues corrected is preferable to Phase 2.

114 See Docket No. ER24-1772-000.

Market Structure

Supply

Table 10-40 shows average hourly offered MW (actual and effective), and average hourly cleared MW (actual and effective) for all hours in the first three months of 2026.[115] Actual MW are adjusted by the historic 100-hour moving average performance score to get effective MW. Offered MW are calculated based on the offers from units that are designated as available for the day. These are daily offers that can be modified on an hourly basis up to 65 minutes before the hour.[116] Eligible MW are calculated from the hourly offers from units with daily offers and units that are offered as unavailable for the day, but still offer MW into some hours. Units with daily offers are permitted to offer above or below their daily offer from hour to hour. As a result of these hourly MW adjustments, the average hourly Eligible MW can be higher than the Offered MW.

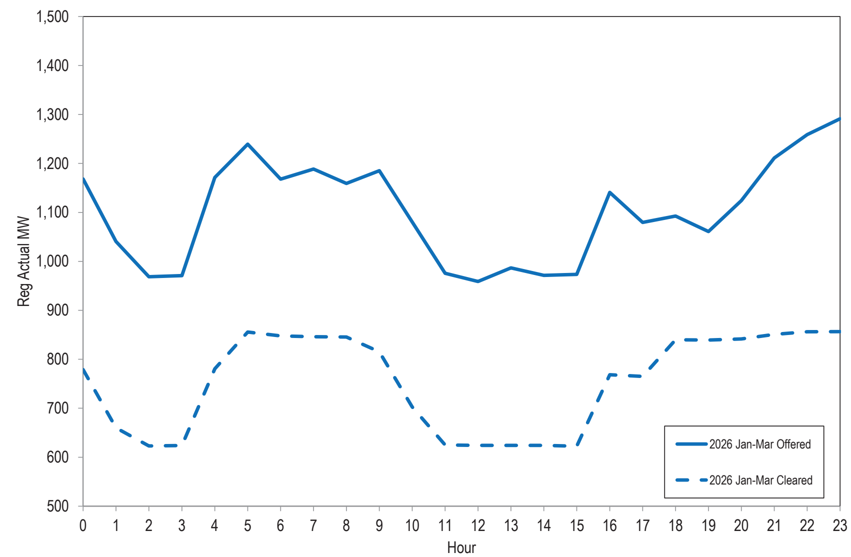
In the first three months of 2026, the average half hour offered supply of regulation for nonramp hours was 958.8 actual MW (835.4 effective MW). In the first three months of 2026, the average half hour offered supply of regulation for shoulder hours was 1,117.2 actual MW (967.8 effective MW). In the first three months of 2026, the average half hour offered supply of regulation for ramp hours was 1,200.8 actual MW (1,048.1 effective MW).

The ratio of the average half hour offered supply of regulation to average half hour regulation demand (actual cleared MW) for nonramp hours was 1.54 in the first three months of 2026. The ratio of the average half hour offered supply of regulation to average half hour regulation demand (actual cleared MW) for shoulder hours was 1.51 in the first three months of 2026. The ratio of the average half hour offered supply of regulation to average half hour regulation demand (actual cleared MW) for ramp hours was 1.41 in the first three months of 2026.

Table 10-40 Hourly average actual and effective MW offered and cleared: January through March, 2026

			By Resource Type	
		All Regulation	Generating Resources	Demand Resources
Actual Offered MW	Ramp	1,200.8	1,136.7	64.1
	Shoulder	1,117.2	1,060.1	57.1
	Nonramp	958.8	902.3	56.5
Effective Offered MW	Ramp	1,048.1	989.2	58.9
	Shoulder	967.8	915.1	52.7
	Nonramp	835.4	783.4	51.9
Actual Cleared MW	Ramp	848.9	785.1	63.9
	Shoulder	740.1	683.1	57.0
	Nonramp	623.3	567.3	56.0
Effective Cleared MW	Ramp	750.1	691.5	58.6
	Shoulder	650.1	597.5	52.6
	Nonramp	550.2	498.6	51.5

Figure 10-34 Average hourly Reg actual MW offered and cleared: January through March, 2026



115 Effective MW are actual MW multiplied by performance score.
116 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.2 Regulation Market Eligibility, Rev. 136 (October 1, 2025).

Battery Projects in the Queue

Significant flaws in the regulation market design led to an over procurement of RegD MW primarily in the form of storage capacity. The incorrect market signals contributed to the significant rise in storage projects entering PJM's interconnection queue from 2019 through 2025, despite clear evidence that the market design was flawed and despite operational evidence that the RegD market was saturated (Table 10-41).

Table 10-41 Active battery storage projects by submitted year: 2014 through March 2026

Year	Number of Storage Projects	Total Capacity (MW)
2014	1	10.0
2015	1	20.0
2016	0	0.0
2017	0	0.0
2018	6	432.0
2019	28	1,939.4
2020	28	2,309.0
2021	56	4,655.8
2022	0	0.0
2023	0	0.0
2024	0	0.0
2025	3	1,575.0
2026 (Jan-Mar)	0	0.0
Total	123	10,941.2

The supply of regulation can be affected by units that leave the PJM markets. If all units that are requesting retirement from PJM markets through the first three months of 2026 actually retire, the supply of regulation in PJM would be reduced by less than one percent.

Demand

The demand for regulation does not change with price. The regulation requirement is set by PJM to meet NERC control standards, based on reliability objectives, which means that a significant amount of judgment is exercised by PJM in determining the actual demand.

Table 10-42 shows the average half hour required regulation by month and the ratio of supply to demand for both actual and effective MW, for ramp, shoulder, and nonramp hours, for the first three months of 2026. The average half hour required regulation by month is an average of the ramp, shoulder, and nonramp hours in the month.

The nonramp regulation requirement of 550.0 effective MW was provided by 623.1 half hour average actual MW in the first three months of 2026. The shoulder regulation requirement of 650.0 effective MW was provided by 740.2 half hour average actual MW in the first three months of 2026. The ramp regulation requirement of 750.0 effective MW was provided by 848.9 half hour average actual MW in the first three months of 2026.

Table 10-42 Required regulation and ratio of supply to requirement: January through March, 2026

Hours	Month	Average Required Regulation (MW)	Average Required Regulation (Effective MW)	Ratio of Supply MW to MW Requirement	Ratio of Supply Effective MW to Effective MW Requirement
Nonramp	Jan	620.5	550.1	1.68	1.65
	Feb	623.8	550.1	1.57	1.55
	Mar	625.1	550.2	1.42	1.40
Shoulder	Jan	738.2	650.1	1.60	1.57
	Feb	744.3	650.2	1.50	1.49
	Mar	738.1	650.0	1.43	1.41
Ramp	Jan	847.0	750.1	1.49	1.46
	Feb	853.5	750.1	1.42	1.41
	Mar	846.2	750.1	1.31	1.30

Market Concentration

In the first three months of 2026, the effective MW weighted average HHI was 1268, which is moderately concentrated.

Table 10-43 includes a monthly summary of three pivotal supplier (TPS) results. In the first three months of 2026, the three pivotal supplier test was failed in 84.5 percent of half hours. The MMU concludes that the PJM Regulation Market in the first three months of 2026 was characterized by structural market power. The results presented here are calculated by PJM.

The MMU has been unable to verify these results, as some of the underlying data necessary to replicate these calculations are not saved. PJM submitted a request to the vendor more than five years ago to save all data necessary for verification.

Table 10-43 Regulation market monthly three pivotal supplier results: January through March, 2026

Month	Percent of Half Hours Pivotal 2026
Jan	75.3%
Feb	82.3%
Mar	95.9%
Average	84.5%

Market Conduct

Offers

Resources seeking to regulate must qualify to follow a regulation signal by passing a test for that signal with at least a 75 percent performance score. The regulating resource must be able to supply at least 0.1 MW of regulation and not allow the sum of its regulating ramp rate and energy ramp rate to exceed its overall ramp rate.[117] When offering into the regulation market, regulating resources must submit a cost-based offer and may submit a price-based offer (capped at $100 per MW) by 1415 the day before the operating day. Regulation resources are also permitted to change and/or submit intraday offers.[118]

Offers in the PJM Regulation Market consist of a capability component for the MW of regulation capability provided and a performance component for the miles (ΔMW of regulation movement) provided. The capability component for cost-based offers is not to exceed the increased fuel costs resulting from operating the regulating unit at a lower output level than its economically optimal output level, plus a $12.00 per MW margin. The $12.00 margin embeds market power in the regulation offers, is not part of the cost of regulation, and should be eliminated. The performance component for cost-based offers is not to exceed the increased costs (increased short run marginal costs including increased fuel costs) resulting from moving the unit up and down to provide regulation. Batteries and flywheels have zero cost for lower efficiency from providing regulation instead of energy, as they are not net energy producers. There is an energy storage loss component for batteries and flywheels as a cost component of regulation performance offers to reflect the net energy consumed to provide regulation service.[119]

Up until 65 minutes before the operating hour, the regulating resource must provide: status (available, unavailable, or self scheduled); capability (movement up and down in MW); regulation maximum and regulation minimum (the highest and lowest levels of energy output while regulating in MW. Resources have the option to submit a minimum level of regulation they are willing to provide.[120]

Demand

All LSEs are required to procure regulation in proportion to their load share. LSEs can purchase regulation in the regulation market, purchase regulation from other providers bilaterally, or self schedule regulation to satisfy their obligation (Table 10-47).[121]

117 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 136 (October 1. 2026).
118 Id. at 3.2.2, at p 62.
119 See "PJM Manual 15: Cost Development Guidelines," § 7.8 Regulation Cost, Rev. 47 (October 1, 2025).
120 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 136 (October 1, 2025).
121 See "PJM Manual 28: Operating Agreement Accounting," § 4.1 Regulation Accounting Overview, Rev. 104 (March 1, 2026).

Market Performance

Results

The top 10 units that received the most regulation uplift in the first three months of 2026 are shown in Table 10-44.

Table 10-44 Top 10 recipients of regulation uplift credits: January through March, 2026

Rank	Parent Company	Unit Name	Fuel Type	Total Regulation Uplift Credit	Share of Total Regulation Uplift Credits
1	Constellation Energy Generation LLC	PE MUDDY RUN 1-8 H	HYDRO	$2,543,123	57.4%
2	Dominion Energy Inc	VP BATH COUNTY 1-6 H	HYDRO	$493,920	11.1%
3	Arclight Capital Holdings LLC	PEP KEYS ENERGY CENTER 1 CC	NATURAL GAS	$178,432	4.0%
4	Apollo Global Management Inc	AP LKLYN 1-4 H	HYDRO	$146,892	3.3%
5	Onward Energy LLC	PEP PANDA 2 F	NATURAL GAS	$64,217	1.4%
6	Vistra Energy Corp	ME ONTELAUNEE 1 F	NATURAL GAS	$62,562	1.4%
7	Strategic Value Partners LLC	ME BIRDSBORO 1 CC	NATURAL GAS	$50,136	1.1%
8	JERA CO INC	PE PHILLIPS ISL LINWOOD 1 CC	NATURAL GAS	$45,365	1.0%
9	Onward Energy LLC	PEP PANDA 1 F	NATURAL GAS	$41,086	0.9%
10	Quantum Energy Partners LLC	PL PATRIOT 1 F	NATURAL GAS	$39,608	0.9%
Total of Top 10				$3,665,340	82.7%
Total Regulation Uplift Credits				$4,434,221	100.0%

Table 10-45 shows the settled regulation MW and credits received for each unit type in the first three months of 2026.

Table 10-45 PJM regulation by source: January through March, 2026 [122]

Year (Jan-Mar)	Source	Number of Units	Settled Regulation (Effective MW)	Percent of Settled Regulation	Clearing Price Credits	Uplift Credits	Total Regulation Credits
2026	Battery	19	380,335	26.8%	$55,929,297	$0	$55,929,297
	Coal	15	10,662	0.8%	$2,414,020	$29,773	$2,443,793
	DR	24	117,909	8.3%	$16,929,862	$0	$16,929,862
	Hydro	25	276,405	19.5%	$43,999,405	$3,216,172	$47,215,577
	Natural Gas	134	635,180	44.7%	$93,421,233	$1,188,275	$94,609,508
Total		217	1,420,491.1	100.0%	$212,693,816	$4,434,221	$217,128,037

Quantity

Figure 10-35 compares average half hour regulation and self scheduled regulation during ramp, shoulder, and nonramp hours on an effective MW basis. Self scheduled regulation averaged 46.6 percent of all effective MW during ramp hours, 48.5 percent of all effective MW during shoulder hours, and 58.0 percent of all effective MW during nonramp hours in the first three months of 2026. Over all hours in the first three months of 2026, self scheduled regulation averaged 50.4 percent of all effective MW (See Table10-46). The average half hour regulation is the amount of regulation that actually cleared and is not the same as the regulation requirement because PJM clears the market within a two percent band around the requirement.

122 Biomass data have been added to the natural gas category based on confidentiality rules.

Figure 10-35 Nonramp, shoulder, and ramp regulation levels: January through March 2026

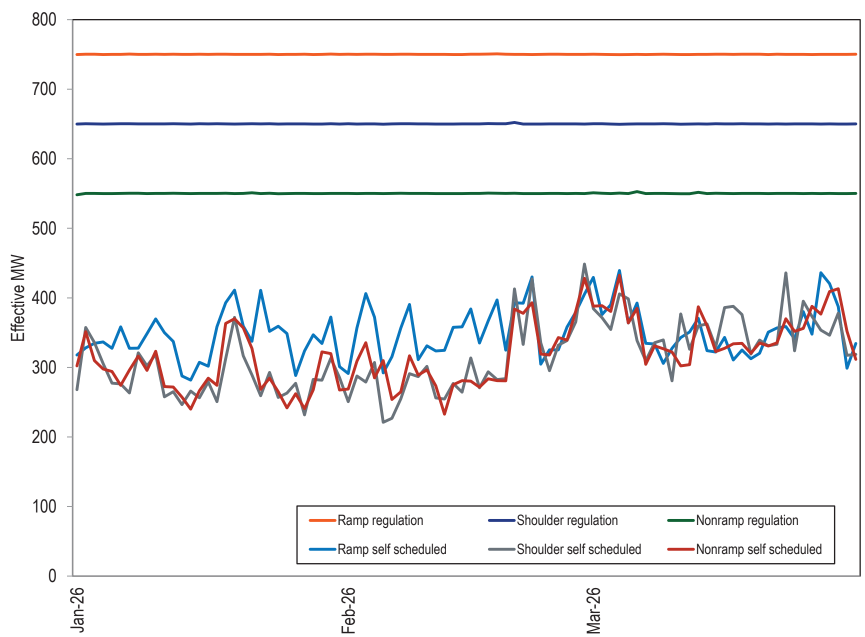


Table 10-46 Total Effective MW and Self Scheduled Effective MW during ramp, shoulder, and non ramp hours: January through March, 2026

Year (Jan-Mar)		Effective MW	Self Scheduled Effective MW	Percent Effective MW
	Ramp	67,510.4	31,476.1	46.6%
	Shoulder	58,510.7	28,363.7	48.5%
2026	Non Ramp	49,514.1	28,702.6	58.0%
Total		175,535.1	88,542.5	50.4%

For total spot market regulation and self scheduled regulation, Table 10-47 shows monthly data for the first three months of 2026, and Table 10-48 shows data for the first three months of 2012 through 2026. Table10-47 and Table10-48 are based on settled (purchased) MW.

Table 10-47 Regulation sources: spot market and self scheduled purchases: January 2026 through March 2026

Year	Month	Spot Market Regulation (Unadjusted MW)	Self Scheduled Regulation (Unadjusted MW)
	Jan	218,130.9	233,173.2
	Feb	184,870.5	219,287.4
2026	Mar	170,750.8	256,823.1
Total		573,752.1	709,283.8

Table 10-48 Regulation sources: spot market and self scheduled: January through March, 2012 through 2026

Year (Jan-Mar)	Spot Market Regulation (Unadjusted MW)	Self Scheduled Regulation (Unadjusted MW)
2012	1,510,190.1	485,672.8
2013	1,026,962.9	342,003.1
2014	724,996.3	404,832.1
2015	670,281.4	411,928.8
2016	583,928.2	546,238.8
2017	534,901.2	520,871.7
2018	678,027.7	395,994.0
2019	539,672.1	500,324.0
2020	515,297.0	557,703.5
2021	542,542.7	556,355.1
2022	687,265.9	369,137.6
2023	464,507.1	524,639.2
2024	376,548.7	622,545.4
2025	437,439.7	561,216.5
2026	573,752.1	709,283.8

In the first three months of 2026, DR provided an average of 63.9 MW of regulation per half hour during ramp hours, 57.0 MW of regulation per half hour during shoulder hours, and 56.0 MW of regulation per half hour during non ramp hours. In the first three months of 2026, generating units supplied an average of 785.1 MW of regulation per half hour during ramp hours, 683.1 MW of regulation per half hour during shoulder hours, and 567.3 MW of regulation per half hour during non ramp hours.

Price

Table 10-49 shows the regulation price and regulation cost per MW for the first three months of 2009 through 2026. The weighted average RMCP for the first three months of 2026 was $148.22 per effective MW. This is an increase of $101.58 per effective MW, or 217.8 percent, from the weighted average RMCP of $46.64 per effective MW in the first three months of 2025. This increase in the regulation clearing price was the result of the increase in the opportunity cost component of RMCP and the price increase associated with the new market design starting on October 1, 2025.

Table 10-49 Comparison of average price and cost for regulation: January through March, 2009 through 2026

Year (Jan-Mar)	Weighted Regulation Market Price	Weighted Regulation Market Cost	Regulation Price as Percent of Cost
2009	$22.25	$34.06	65.3%
2010	$17.97	$31.24	57.5%
2011	$11.52	$25.03	46.0%
2012	$12.62	$16.75	75.3%
2013	$33.91	$39.36	86.2%
2014	$92.97	$112.30	82.8%
2015	$47.91	$58.23	82.3%
2016	$15.55	$17.92	86.8%
2017	$13.89	$18.47	75.2%
2018	$40.33	$49.60	81.3%
2019	$14.05	$18.49	76.0%
2020	$10.99	$13.91	79.0%
2021	$17.18	$21.01	81.8%
2022	$45.24	$55.64	81.3%
2023	$17.83	$24.20	73.7%
2024	$28.00	$36.40	76.9%
2025	$46.64	$58.86	79.2%
2026	$148.22	$151.56	97.8%

The introduction of fast start pricing in the PJM energy market on September 1, 2021, had an effect on the regulation market LOC included in regulation offers and in the resulting clearing price for regulation. Table10-50 shows the effect of fast start pricing on the regulation market monthly capability component of price and the total regulation market clearing price from September 2021 through March 2026. In the first three months of 2026, fast start pricing increased the average regulation market clearing price by $81.72 (an increase of 122.9 percent), from $66.50 per effective MW to $148.22 per effective MW, compared to dispatch pricing. This resulted in an additional $116.0 million in regulation credits.

Table 10-50 Comparison of fast start and dispatch pricing: September 2021 through March 2026[123]

		Weighted Average Price ($/Perf. Adj. Actual MW)				
		Capability Clearing Price		Regulation Market Clearing Price		
Year	Month	Dispatch	Fast Start	Dispatch	Fast Start	Percent Fast Start Increase
2021	Sep	$27.22	$29.08	$28.55	$30.41	6.5%
	Oct	$35.64	$39.92	$37.12	$41.40	11.5%
	Nov	$50.56	$54.40	$52.43	$56.28	7.3%
	Dec	$25.62	$27.37	$27.05	$28.79	6.4%
2022	Jan	$68.25	$71.14	$69.68	$72.56	4.1%
	Feb	$31.14	$31.93	$32.76	$33.55	2.4%
	Mar	$23.91	$25.94	$25.70	$27.73	7.9%
	Apr	$45.07	$48.85	$47.49	$51.27	7.9%
	May	$38.09	$41.85	$39.84	$43.60	9.4%
	Jun	$47.26	$52.57	$49.17	$54.48	10.8%
	Jul	$47.40	$54.51	$48.92	$56.04	14.5%
	Aug	$57.43	$64.13	$59.17	$65.87	11.3%
	Sep	$46.17	$48.84	$48.07	$50.73	5.5%
	Oct	$33.38	$36.76	$35.33	$38.70	9.6%
	Nov	$21.29	$23.08	$22.42	$24.21	8.0%
	Dec	$115.65	$112.52	$116.94	$113.81	(2.7%)
Total		$48.66	$51.82	$50.37	$53.53	6.3%
2023	Jan	$16.61	$17.25	$17.58	$18.22	3.7%
	Feb	$15.12	$15.48	$16.29	$16.65	2.2%
	Mar	$17.11	$17.80	$17.89	$18.57	3.8%
	Apr	$21.51	$23.20	$22.60	$24.29	7.5%
	May	$22.75	$24.58	$24.31	$26.14	7.5%
	Jun	$19.77	$20.88	$21.27	$22.38	5.2%
	Jul	$21.45	$23.43	$22.56	$24.54	8.8%
	Aug	$20.10	$21.32	$21.17	$22.39	5.8%
	Sep	$22.34	$23.92	$23.49	$25.08	6.7%
	Oct	$28.11	$32.37	$29.25	$33.51	14.6%
	Nov	$18.48	$20.83	$18.95	$21.30	12.4%
	Dec	$16.78	$18.12	$17.81	$19.15	7.5%
Total		$20.01	$21.60	$21.10	$22.69	7.5%
2024	Jan	$35.33	$36.70	$36.91	$38.28	3.7%
	Feb	$17.72	$19.44	$18.70	$20.42	9.2%
	Mar	$20.05	$22.88	$21.21	$24.04	13.3%
	Apr	$20.36	$24.52	$20.75	$24.90	20.0%
	May	$32.60	$37.59	$33.66	$38.64	14.8%
	Jun	$27.57	$28.96	$28.29	$29.68	4.9%
	Jul	$37.03	$39.87	$38.51	$41.35	7.4%
	Aug	$29.85	$31.48	$30.56	$32.18	5.3%
	Sep	$25.66	$28.31	$27.36	$30.01	9.7%
	Oct	$33.33	$35.59	$34.27	$36.53	6.6%
	Nov	$25.68	$28.52	$26.60	$29.45	10.7%
	Dec	$31.90	$33.14	$33.45	$34.69	3.7%
Total		$28.29	$30.76	$29.39	$31.86	8.4%
2025	Jan	$57.21	$59.04	$60.17	$61.99	3.0%
	Feb	$34.73	$36.62	$36.51	$38.41	5.2%
	Mar	$31.37	$35.60	$33.70	$37.93	12.6%
	Apr	$26.33	$31.51	$26.84	$32.02	19.3%
	May	$26.44	$28.74	$27.61	$29.91	8.4%
	Jun	$56.45	$61.08	$57.81	$62.43	8.0%
	Jul	$37.82	$43.07	$39.31	$44.56	13.3%
	Aug	$26.10	$29.39	$27.48	$30.77	12.0%
	Sep	$36.70	$39.27	$38.49	$41.06	6.7%
	Oct	$50.79	$125.89	$52.82	$127.92	142.2%
	Nov	$33.23	$62.87	$33.69	$63.33	88.0%
	Dec	$37.65	$66.64	$38.26	$67.24	75.7%
Total		$40.44	$53.66	$41.46	$55.05	32.8%
2026	Jan	$85.24	$142.52	$86.35	$143.64	66.3%
	Feb	$75.01	$196.52	$75.46	$196.96	161.0%
	Mar	$37.26	$107.08	$37.39	$107.22	186.7%
Total		$65.93	$147.64	$66.50	$148.22	122.9%

123 The performance component of the regulation market clearing price is unaffected by fast start pricing.

Figure 10-36 shows the capability price, performance price, and the opportunity cost component for the PJM Regulation Market on an effective MW basis. The regulation clearing price is determined based on the marginal unit's total offer (RCP + RPP + PJM calculated LOC). Then the maximum performance offer price (RPP) of any of the cleared units is used to set the marginal performance clearing price for the purposes of settlements. The difference between the marginal total clearing price and the highest performance clearing price (RMPCP) is the marginal capability clearing price (RMCCP). The capability price presented here is equal to the clearing price, minus the maximum cleared performance offer price. This data is based on actual five minute interval operational data.

Figure 10-36 illustrates the components of the regulation market clearing price. Each section represents the contribution of the lost opportunity cost (green area), capability price (blue area), and performance price (orange area), to the total price. From this figure, it is clear that the lost opportunity cost is the largest component of the total clearing price. In the first three months of 2026, LOC accounted for 90.1 percent of the daily weighted average capability price, and 89.8 percent of the daily weighted average total clearing price.

Figure 10-36 Regulation market clearing price components (Dollars per effective MW): January through March, 2026

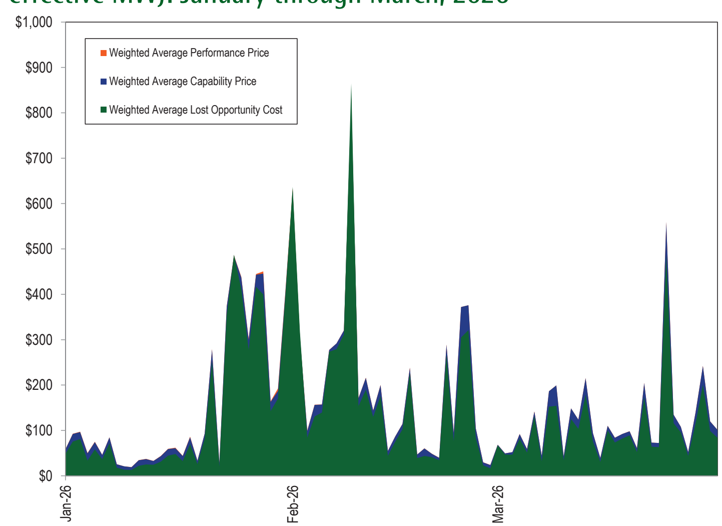


Table 10-51 shows the capability and performance components of the monthly average regulation prices. These components differ from the components of the marginal unit's offers in Figure 10-36 because the performance component of the settlement price for each hour is determined from the average of the highest performance offers in each five-minute interval, calculated independent of the marginal unit's offers in those intervals.

Table 10-51 Regulation market monthly component of price (Dollars per MW): January through March, 2026

Year	Month	Weighted Average Regulation Market Capability Clearing Price ($/Effective MW)	Weighted Average Regulation Market Performance Clearing Price ($/Effective MW)	Weighted Average Regulation Market Clearing Price ($/Effective MW)
2026	Jan	$142.52	$1.11	$143.64
	Feb	$196.52	$0.44	$196.96
	Mar	$107.08	$0.13	$107.22
Average		$147.64	$0.57	$148.22

Monthly and total scheduled regulation MW and regulation charges, as well as monthly average regulation price and regulation cost are shown in Table 10-52. Total scheduled regulation is based on settled effective MW. The total of all regulation charges in the first three months of 2026 was $217,491,353.

Table 10-52 Total regulation charges: January through March, 2026

Year	Month	Scheduled Regulation (Effective MW)	Total Regulation Charges ($)	Weighted Average Regulation Market Price ($/Effective MW)	Cost of Regulation ($/ Effective MW)	Price as Percent of Cost
2026	Jan	501,730.2	$74,547,172	$143.64	$148.58	96.7%
	Feb	451,980.3	$90,476,677	$196.96	$200.18	98.4%
	Mar	481,303.7	$52,467,503	$107.22	$109.01	98.4%
Total		1,435,014.2	$217,491,353	$148.22	$151.56	97.8%

The capability, performance, and opportunity cost components of the cost of regulation are shown in Table10-53. Total scheduled regulation is based on settled effective MW. In the first three months of 2026, the average total cost of regulation was $151.56 per MW. In the first three months of 2026, the monthly average capability component cost of regulation was $147.43. In the first three months of 2026, the monthly average performance component cost of regulation was $0.78

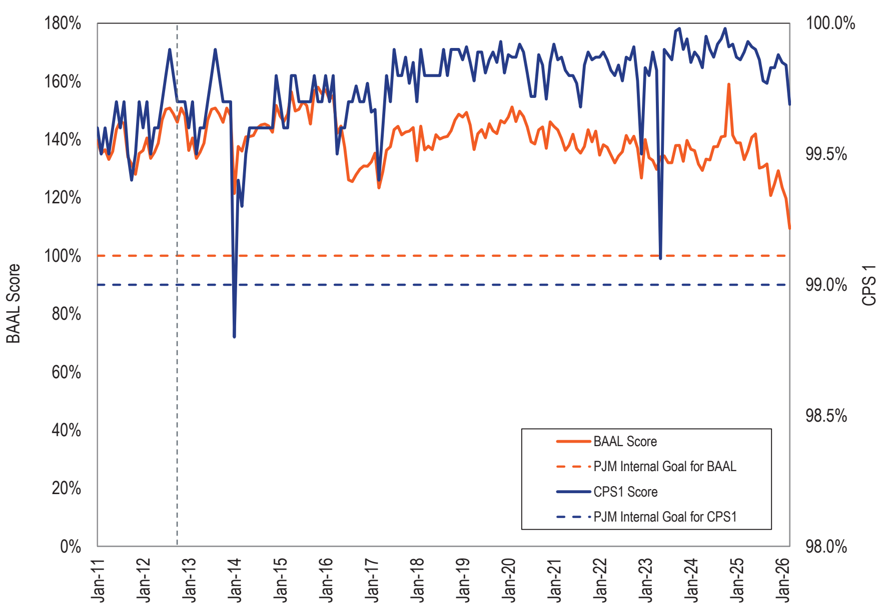
Table 10-53 Components of regulation cost: January through March, 2026

Year	Month	Scheduled Regulation (Effective MW)	Cost of Regulation Capability ($/Effective MW)	Cost of Regulation Performance ($/ Effective MW)	Opportunity Cost ($/ Effective MW)	Total Cost ($/Effective MW)
	Jan	501,730.2	$142.07	$1.57	$4.94	$148.58
	Feb	451,980.3	$196.36	$0.60	$3.22	$200.18
2026	Mar	481,303.7	$107.08	$0.14	$1.80	$109.01
Total		1,435,014.2	$147.43	$0.78	$3.34	$151.56

Performance Standards

PJM's performance as measured by CPS1 and BAAL standards is shown in Figure 10-37 for every month from January 2011 through March 2026 with the dashed vertical line marking the date (October 1, 2012) of the implementation of the Performance Based Regulation Market design.[124] The horizontal dashed lines represent PJM internal goals for CPS1 and BAAL performance.

Figure 10-37 Monthly CPS1 and BAAL performance: January 2011 through March 2026



124 See *2019 Annual State of the Market Report for PJM*, Appendix F: Ancillary Services.

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 the demonstrated ability of a generating unit to automatically remain operating at reduced levels when disconnected from the grid (automatic load rejection or ALR).[125]

PJM does not have a market to provide black start service, but compensates black start resource owners on the basis of cost of service rates defined in the tariff.[126] Currently, there are a small number of units in unique circumstances with bilateral agreements with their transmission operator (TO) to provide black start service that were entered into prior to joining PJM. These units are compensated directly by the TO. PJM has the ability to use a backstop black start service acquisition process under some circumstances that would result in shifting responsibility from PJM to the TOs.

PJM defines required black start capability zonally, while recognizing that the most effective way to provide black start service is a regional approach that recognizes cost effective ways to provide black start across transmission zonal boundaries.[127] PJM does not adequately use a regional or cross zonal approach to providing black start. Under the current rules PJM has substantial flexibility in procuring black start resources and is responsible for black start resource selection under most conditions.[128] But PJM's stated principles for system restoration are not fully incorporated in the rules in Schedule 6A. Costs should also be allocated on a regional basis to reflect the regional benefits of black start service.

The MMU recommends that black start planning and coordination be on a regional basis recognizing cross zonal cranking paths and not on a narrowly or purely zonal basis. The region as a whole benefits from black start service,

125 OATT Schedule 1 § 1.3BB.
126 See OATT Schedule 6A para. 18.
127 See Motion for Leave to Answer and Answer of PJM Interconnection, L.L.C to Comments, FERC Docket No. ER13-1911-000 (August 19, 2013) at 5 ("To be sure, restoration plans utilizing interconnecting Transmission Owners is not new and is currently included in all restoration plans today. Geographic or political boundaries play no role in the evaluation of the most reliable and efficient restoration strategies.").
128 See Docket No. ER13-1911-000.

regardless of the transmission zone in which it is located, and the costs of black start service should be shared equally across the region.

Fuel Assurance

Black start units must maintain enough fuel to allow for 16 hours of run time or for the minimum time required by the TO whichever is less. Generator operators must notify PJM and the TO when fuel levels fall below the required levels.[129] A black start unit must be able to start without an outside electrical supply or a unit with a high operating factor with demonstrated ability to automatically remain operating, at reduced levels, when disconnected to the grid.[130]

Fuel assured black start units have to meet the same requirements as black start units including maintaining enough onsite fuel and non-fuel consumables for three starts and 16 hours of full load operation, or operate on two or more interstate pipelines independently. Hybrid or intermittent resources must be able to provide 16 hours each day of full load with 90 percent confidence, although the 16 hours do not need to be continuous. Fuel assured black start units are required to provide annual certification that they met the minimum fuel and non-fuel consumables requirements. PJM may also request certification at any time. If a fuel assured black start unit's fuel or non-fuel consumables drop below their ability to run 16 hours at full load and three starts they must report to PJM within 24 hours. In any month a fuel assured black start unit fails to maintain the fuel and non-fuel consumables they will not receive black start revenues in that month unless it meets the exception rules.[131] Exceptions rules are for an approved outage and if levels go below 16 hours as the result of a PAI.[132] Black start units that are not fuel assured do not lose black start revenues if their fuel and or non-fuel consumables fall below a 16 hour run time and or cannot make three starts.

By order issued October 6, 2023, the FERC approved revisions to Schedule 6A defining fuel assurance for black start units, effective July 12, 2023.[133] The revisions were approved over the protest of the MMU, which identified significant flaws.[134] The planning criteria for fuel assured units and charges are applied on a zonal basis and not a regional basis, even though PJM is a regional transmission operator. The revisions to the tariff ignore the attributes of existing fuel assured units if they do not offer into the fuel assurance RFP. Intermittent resources are treated as if they are fuel assured. The X allocation factor for fuel assured hydro units is arbitrarily doubled from 0.01 to 0.02. The Z incentive factor for fuel assured units is arbitrarily doubled from 10 percent to 20 percent. For black start units in service prior to June 6, 2021, the rules apply CRF rates that ignore significant reductions in federal tax rates, including depreciation provisions, resulting in significant overpayments by PJM customers. The rules do not address environmental permits, which may limit the ability of units to provide black start service. The rules do not define the provision of black start service by DERs. The rules do not require testing units without notice to operators. The rules do not address the availability of natural gas and stored water levels. Reporting requirements for onsite fuel are not adequate. The reliability backstop improperly depends on TOs to secure black start service if PJM has two failed auctions.

The MMU recommends that the fuel assurance rules be modified to recognize actual fuel assured resources within and across zones.

Definition of Black Start Costs

In the November 8, 2024, MIC meeting PJM proposed to change the definition of Net CONE used in the Black Start Base Formula Rate (BFR) calculation.[135] The Base Formula Rate is a formula based cost of service rate and not a market based rate. The rationale was that Net CONE values based on a combined cycle reference resource defined for the capacity market could be negative at times. PJM did not retract its proposal even after PJM decided to use a combustion turbine as the reference resource rather than a combined cycle as the reference resource. That change eliminated PJM's identified issue with negative Net CONE values. The MMU presented historical information on payments under the BFR rate and argued that no change is needed to the Net

129 See "PJM Manual 36: Minimum Critical Black start Requirements," § A.1.2 (June 15, 2025).
130 *See* OATT Schedule 6A para. 2.
131 *See* OATT Schedule 6A para. 14.
132 See "PJM Manual 12: Balancing Operations," §4.5.10 Performance Standards Non-Performance §4.5.14, Rev. 56 (October 1, 2025).
133 See 85 FERC ¶ 91,000.
134 See Comments of the Independent Market Monitor for PJM, FERC Docket No. ER23-1874-000 (June 6, 2023) and Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, FERC Docket No. ER23-1874-000 (July 6, 2023).
135 See MIC, Problem Statement and Issues Charge, "Black Start Base Formula Rate," <https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2024/20241108/20241108-item-03-1---black-start-base-formula-rate---problem-statement.pdf> and <https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2024/20241108/20241108-item-03-2---black-start-base-formula-rate---issue-charge.pdf> (Nov. 8, 2024).

CONE calculation.[136] PJM filed its proposal with the Commission on April 30, 2025.[137] The MMU filed a protest, and, after a deficiency letter issued and PJM responded, filed additional comments.[138]

Ultimately PJM's argument was simply that the current tariff calculation would result in a short term decrease in black start payments under the Base Formula Rate which includes Net CONE, and PJM did not want the rate to decrease. PJM proposed to use average Net CONE for the entire RTO over the last five years as a fixed value subject to escalation. Both Gross CONE and the net revenue offset will be escalated using an inflation index. It is illogical to escalate net revenue because net revenue is a function of the dynamics of the energy market and the fuel markets. Given the current and expected high levels of Gross CONE compared to the five year average, PJM's proposal could actually reduce payments to these black start resources compared to the status quo. PJM did not address that possibility. PJM failed to explain why their proposal is a reasonable approach to compensating these resources for providing black start service. PJM provided no information about the actual costs of providing black start service. PJM provided no information about the actual mark up over costs currently paid to these black start resources. PJM's proposal does not approximate black start service costs and fails to even attempt to demonstrate any relationship to black start service costs. Under an approach that uses Net CONE, PJM does not justify using system wide Net CONE rather than locational Net CONE.

The MMU recommends that the black start rate under the Base Formula Rate should be based on the actual cost of providing the black start service, plus an incentive, rather than the unsupported use of Net CONE, escalated each year.

Black Start Backstop Acquisition Process

PJM Manual 14D defines a Black Start Reliability Backstop Process that is implemented in the event that PJM does not acquire enough black start resources through the RFP process. One option under this process is that one or more Transmission Owners can take responsibility for procuring the needed black start resources in their zones.

There can be up to four steps in the reliability backstop process. The first step is triggered by: a black start generation shortage or a failure to meet the fuel assurance criteria in a zone; and two failed RFPs; and no cross-zonal solutions available; and no RTEP transmission solutions available. In the second step, PJM, affected TOs, and affected state(s) will discuss the shortage, the costs, and the TO proposal. They will consider the impacts on the restoration plan and PJM will determine whether to issue a reliability backstop RFP. If a reliability backstop RFP is not issued, PJM will monitor the shortfall. If a reliability backstop RFP is issued then a third step will be taken. In the third step, an RFP will be issued by PJM to address the shortfall. The TO solution at this point will be made public excluding CEII information. The TO solution may be owned by the TO, generation owning affiliate or contracted for by the TO with a third party generation owner. The TO is obligated to provide a proposal. In the fourth step, PJM will evaluate the RFP responses and compare them to the TO solution(s). If the TO solution is the only option received then it will be implemented.[139]

The backstop process for black start service is flawed. PJM has units in zones which are fuel assured capable but are ignored if they do not bid into a fuel assured RFP. There is no reason to believe that TOs can procure black start more effectively than PJM. TOs should not own generation under cost of service regulation because it is inconsistent with competitive markets. PJM should continue its efforts until their goals are met. It is PJM's responsibility to manage black start capability.[140]

The MMU recommends that the reliability backstop for black start service be eliminated. There is no reason that PJM cannot acquire black start resources if the TOs can acquire black start resources.

136 See MIC, IMM Education, Black Start Costs and Net CONE <https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2025/20250205/20250205-item-03-2---black-start-base-formula-rate---imm-solution.pdf> (February 5, 2025).

137 See PJM Filing, Docket No. ER25-2123-000.

138 See Comments of the Independent Market Monitor for PJM, FERC Docket No. ER25-2123-000 (May 21, 2025); Comments of the Independent Market Monitor for PJM, FERC Docket No. ER25-2123-000 (July 21, 2025).

139 See "PJM Manual 14D: Generator Operational Requirements," §10.3 Black Start Reliability Backstop Process, Rev. 69 (December 17, 2025).

140 See 144 FERC ¶ 61,191 (2013).

RFPs for Black Start Service

PJM requires a minimum of one fuel assured black start site in each zone or two non fuel assured black start sites connected to different pipelines per zone.[141] New or existing black start units that wish to be designated as fuel assured black start units must offer into the PJM fuel assured RFP.[142]

In order for a unit to be considered fuel assured, it must have one of five characteristics: onsite fuel; be capable of operating independently on two or more pipelines; be directly connected to a natural gas gathering system; hydro, non-hydro and intermittent resources must be capable of 16 hours of noncontinuous full load operation with 90 percent confidence. A zone also meets the fuel assurance requirement if the zone includes a minimum of two gas units connected to two separate natural gas pipelines.[143]

On April 7, 2021, PJM issued an incremental RFP for black start service in the BGE and PEPCO Zones. On November 1, 2021, PJM made awards for the April 7, 2021, incremental RFP. The in service date was May 2024. On August 1, 2022, PJM issued an incremental RFP for black start service in the PECO Zone. No awards were made.

On June 20, 2023, PJM issued an RTO wide request for proposals (RFP) in accordance with the five year black start selection process. The RFP was for black start service and fuel assured black start service. PJM awarded multiple existing black start units fuel assured black start service status in eight zones.

On April 29, 2024, PJM issued an incremental RFP for fuel assured black start service, because the 2023 RFP did not attract offers for fuel assured black start units in all zones. The April 29, 2024, RFP failed to result in acceptable offers in six zones.

Despite the fact that the April 29, 2024, auction process is not expected to be completed until the end of June 2026, PJM has started the reliability backstop process.

141 See "PJM Manual 36: System Restoration," §1.2 Minimum Critical Black Start Requirement, Rev. 35 (June. 15, 2025).
142 See "PJM Manual 14D: Generator Operational Requirements," §10.1 Black Start Selection Process, Rev. 69 (December 17, 2025).
143 See "PJM Manual 12: Balancing Operations," §4.5.7 Minimum Critical Black Start Unit and Fuel Assurance Black Start Unit Requirements, Rev. 55 (June. 18, 2025).

PJM has implemented the reliability backstop to secure fuel assured black start service in six zones. There are three zones where no units offered into the fuel assured RFP. In the six zones where a fuel assured reliability backstop process has started, PJM has units that meet the technical requirements to be fuel assured. The actual fuel assurance characteristics of these black start units were ignored because they did not offer into the fuel assured RFP.

The premature implementation of the reliability backstop process illustrates the inefficiency and excess cost to customers of ignoring the attributes of existing fuel assured units if they do not offer into the fuel assurance RFP. PJM has failed to consider whether existing black start resources meet the fuel assurance goals regardless of whether they applied for fuel assurance status.

Black Start Charges

Total black start charges are the sum of black start revenue requirement charges and black start uplift (operating reserve) charges.

Black start revenue requirements for black start units consist of fixed black start service costs, variable black start service costs, training costs, fuel storage costs, and an incentive factor applicable when CRF rates are not used. The tariff specifies how to calculate each component of the revenue requirement formula.[144]

Fixed black start service costs are calculated using one of three methods chosen by the black start provider from the options defined in the OATT Schedule 6A: base formula rate; capital cost recovery rate; or incremental black start NERC-CIP cost recovery. The base formula rate is Net CONE multiplied by the black start unit's capacity multiplied by the X factor. The X factor is 0.01 for hydro units and 0.02 for CT units. The capital recovery rate is the capital investment multiplied by the CRF rate. The incremental NERC-CIP cost, for existing black start resources that need to add additional capital to meet NERC-CIP requirements, is calculated using the capital cost recovery rate. Black start uplift charges are paid to units committed in real time to provide black start service or for black start testing.[145] Total black start charges

144 *See* OATT Schedule 6A para. 18.
145 There are no black start units currently using the ALR option.

are allocated monthly to PJM customers based on their zone and nonzone peak transmission use and point to point transmission reservations.[146]

No black start units have requested new or additional black start NERC – CIP Capital Costs.[147]

In the first three months of 2026, total black start charges were $11.4 million, a decrease of $4.8 million (29.4 percent) from 2025. In the first three months of 2026, total revenue requirement charges were $11.2 million, a decrease of $04.7 million (129.6 percent) from the first three months of 2025. In the first three months of 2026, total uplift charges were $0.21 million, a decrease of $0.04 million (14.9 percent) from 2025. Table10-54 shows total charges for January through March of each year from 2010 through 2026.[148]

Table 10-54 Black start revenue requirement charges: January through March, 2010 through 2026

Jan-Mar	Revenue Requirement Charges	Uplift Charges	Total
2010	$2,673,689	$0	$2,673,689
2011	$2,793,709	$0	$2,793,709
2012	$3,864,301	$0	$3,864,301
2013	$5,412,855	$22,210,646	$27,623,501
2014	$5,104,104	$7,561,533	$12,665,637
2015	$10,276,712	$4,699,965	$14,976,676
2016	$16,677,315	$57,082	$16,734,396
2017	$17,731,836	$63,384	$17,795,220
2018	$16,840,283	$23,309	$16,863,592
2019	$15,938,101	$36,188	$15,974,289
2020	$15,944,660	$40,587	$15,985,247
2021	$16,483,246	$86,695	$16,569,941
2022	$17,408,156	$125,306	$17,533,462
2023	$16,721,128	$143,876	$16,865,004
2024	$16,482,115	$185,047	$16,667,162
2025	$15,936,476	$252,214	$16,188,690
2026	$11,216,962	$214,735	$11,431,697

Black start zonal charges in the first three months of 2026 ranged from $0 in the OVEC and REC Zones to $2.2 million in the AEP Zone. For each zone, Table10-55 shows black start charges, zonal peak loads, and black start rates (calculated as charges per MW-day).[149] [150]

146 OATT Schedule 6A (paras. 25, 26 and 27 outline how charges are to be applied).
147 OATT Schedule 6A para. 21. "The Market Monitoring Unit shall include a Black Start Service summary in its annual State of the Market report which will set forth a descriptive summary of the new or additional Black Start NERC-CIP Capital costs requested by Black Start Units, and include a list of the types of capital costs requested and the overall cost of such capital improvements on an aggregate basis such that no data is attributable to an individual Black Start Unit."
148 Starting December 1, 2012, PJM defined a separate black start uplift category. ALR units accounted for the high uplift charges in 2013 – 2015. All ALR units had been replaced by April 2015.
149 See "PJM Manual 27: Open Access Transmission Tariff Accounting," § 7.3 Black Start Service Charges, Rev. 102 (Jan. 23, 2025).
150 For each zone and import export/wheels the black start rates ($/MW day) are calculated by taking total charges by zone and divided by peak load then divided by days in the period.

Table 10-55 Black start zonal charges: January through March, 2025 and 2026[151]

	Jan-Mar 2025					Jan-Mar 2026				
Zone	Revenue Requirement Charges	Uplift Charges	Total Charges	Peak Load (MW)	Black Start Rate ($/MW-day)	Revenue Requirement Charges	Uplift Charges	Total Charges	Peak Load (MW)	Black Start Rate ($/MW-day)
ACEC	$593,540	$0	$593,540	2,566	$2.57	$572,452	$0	$572,452	2,709	$2.35
AEP	$2,419,746	$1,595	$2,421,341	22,318	$1.21	$2,219,434	$0	$2,219,434	23,710	$1.04
APS	$1,384,337	$18,366	$1,402,703	8,938	$1.74	$697,878	$0	$697,878	9,792	$0.79
ATSI	$759,099	$9,162	$768,261	12,508	$0.68	$734,915	$9,154	$744,069	12,659	$0.65
BGE	$938,896	$8,803	$947,699	6,766	$1.56	$947,655	$0	$947,655	6,585	$1.60
COMED	$1,990,114	$35,796	$2,025,910	21,560	$1.04	$726,765	$0	$726,765	20,714	$0.39
DAY	$67,841	$48,313	$116,154	3,365	$0.38	$50,648	$21,945	$72,593	3,396	$0.24
DUKE	$97,989	$1,819	$99,807	5,171	$0.21	$101,810	$0	$101,810	5,190	$0.22
DUQ	$217,348	$1,272	$218,621	2,691	$0.90	$221,182	$0	$221,182	2,695	$0.91
DOM	$1,082,911	$91,595	$1,174,506	23,118	$0.56	$692,646	$169,966	$862,612	24,678	$0.39
DPL	$328,117	$0	$328,117	4,189	$0.87	$209,165	$0	$209,165	4,198	$0.55
EKPC	$85,764	$0	$85,764	3,748	$0.25	$89,415	$0	$89,415	3,757	$0.26
JCPLC	$148,880	$0	$148,880	6,184	$0.27	$117,860	$0	$117,860	6,273	$0.21
MEC	$106,215	$3,891	$110,106	3,067	$0.40	$88,617	$0	$88,617	3,000	$0.33
OVEC	$0	$0	$0	NA	NA	$0	$0	$0	NA	NA
PECO	$362,849	$976	$363,825	8,652	$0.47	$340,352	$425	$340,776	8,380	$0.45
PE	$976,682	$0	$976,682	2,953	$3.67	$246,470	$0	$246,470	2,909	$0.94
PEPCO	$1,744,125	$13,583	$1,757,708	6,162	$3.17	$1,836,737	$0	$1,836,737	6,016	$3.39
PPL	$1,069,522	$324	$1,069,846	7,460	$1.59	$395,286	$0	$395,286	8,057	$0.55
PSEG	$395,288	$0	$395,288	10,152	$0.43	$202,234	$0	$202,234	10,230	$0.22
REC	$0	$0	$0	NA	NA	$0	$0	$0	NA	NA
(Imp/Exp/Wheels)	$1,167,212	$16,720	$1,183,932	12,800	$1.03	$725,442	$13,245	$738,686	11,432	$0.72
Total	$15,936,476	$252,214	$16,188,690	174,365	$1.03	$11,216,962	$214,735	$11,431,697	176,378	$0.72

Table 10-56 provides a revenue requirement estimate by zone for the 2025/2026, 2026/2027, and 2027/2028 Delivery Years.[152] Revenue requirement values are rounded up to the nearest $50,000, reflecting the uncertainty about future black start revenue requirement costs. These values are illustrative only. The estimates are based on the best available data including current black start unit revenue requirements, expected black start unit termination and in service dates, changes in recovery rates, and owner provided cost estimates of incoming black start units at the time of publication and may change significantly. The estimates do not reflect the impact of FERC decisions that could affect compensation for black start.

151 Peak load for each zone is used to calculate the black start rate per MW day.
152 The System Restoration Strategy Task Force requested that the MMU provide estimated black start revenue requirements.

Table 10-56 Black start zonal revenue requirement estimate: 2025/2026 through 2027/2028 Delivery Years

Zone	2025 / 2026 Revenue Requirement	2026 / 2027 Revenue Requirement	2027 / 2028 Revenue Requirement
ACEC	$2,450,000	$2,500,000	$2,350,000
AEP	$9,200,000	$8,100,000	$8,250,000
APS	$2,750,000	$1,150,000	$1,200,000
ATSI	$3,250,000	$3,200,000	$3,200,000
BGE	$4,150,000	$4,150,000	$4,150,000
COMED	$3,000,000	$2,550,000	$2,650,000
DAY	$250,000	$250,000	$300,000
DUKE	$400,000	$500,000	$500,000
DUQ	$950,000	$400,000	$400,000
DOM	$3,050,000	$2,700,000	$2,800,000
DPL	$1,050,000	$1,050,000	$1,050,000
EKPC	$350,000	$400,000	$450,000
JCPLC	$600,000	$650,000	$700,000
MEC	$550,000	$600,000	$650,000
OVEC	$0	$0	$0
PECO	$1,450,000	$1,550,000	$1,600,000
PE	$1,000,000	$1,150,000	$1,200,000
PEPCO	$7,850,000	$7,900,000	$7,900,000
PPL	$1,550,000	$1,600,000	$1,650,000
PSEG	$850,000	$900,000	$950,000
REC	$0	$0	$0
Total	$44,700,000	$41,300,000	$41,950,000

CRF Issues

The capital recovery factor (CRF) defines the revenue requirement of black start units when new equipment is added to provide black start capability.[153] The CRF is a rate, which when multiplied by the investment, provides for a return on and of capital over a defined time period. CRFs are calculated using a formula (or a correctly defined standard financial model) that accounts for the weighted average cost of capital and its components, plus depreciation and taxes. The PJM CRF table was created in 2007 as part of the new RPM capacity market design.[154] That CRF table provided for the accelerated return of incremental investment in capacity resources based on concerns about the fact that some old coal units would be making substantial investments related to pollution control. The CRF values were later added to the black start rules.[155]

The CRF table for existing black start units includes the column header, term of black start commitment, which is misleading and incorrect. The column is simply the cost recovery period. Accelerated recovery reduces risk to black start units and should not be the basis for a shorter commitment. Full payment of all costs of black start investment on an accelerated basis should not be a reason for a shortened commitment period. Regardless of the recovery period, payment of the full costs of the black start investment should require commitment for the life of the unit.[156] In addition, there is no need for such short recovery periods for black start investment costs. Two periods, based on unit age, are more than adequate.

The values in the original CRF tariff tables, in Schedule 6A and Attachment DD § 6.8(a), were based on 2007 income tax rates and depreciation rules. The U.S. Internal Revenue Code changed significantly in December 2017 with updates to the corporate income tax rate and depreciation rules.[157] [158] The PJM CRF table did not change to reflect these changes.[159] [160] The PJM CRF tables in the tariff should have been updated immediately to reflect the change in the tax laws. As a result, CRF values have overcompensated black start units since the 2017 changes to the tax code. On April 7, 2021, PJM filed with FERC to update the CRF values for new black start service units.[161] PJM proposed to bifurcate the CRF calculation, applying an updated CRF calculation that incorporates the new federal tax law to new black start units while leaving the outdated and incorrect CRF in place for existing black start units. Rather than fix the inaccurate CRF values used for existing black start units, PJM's filing would have made the use of inaccurate values permanent. The MMU filed comments

153 *See* OATT Schedule 6A para. 18.

154 See OATT Attachment DD § 6.8(a).

155 See OATT Schedule 6A.

156 PJM's recent filing to revise Schedule 6A includes a required commitment to provide black start service for the life of the unit. See FERC Docket No. ER21-1635.

157 Tax Cuts and Jobs Act, Pub. L. No. 115-97, 131 Stat. 2096, Stat. 2105 (2017).

158 26 U.S. Code §11(b).

159 The corporate tax rate was lowered to 21 percent and bonus depreciation, which allows generator owners to depreciate 100 percent of the capital investment in the first year of operation, was introduced.

160 Bonus depreciation is 100 percent for capital investments placed in service after September 27, 2017, and before January 1, 2023. Bonus depreciation is 80 percent for capital investments placed in service after December 31, 2022, and before January 1, 2024, and the bonus depreciation level is reduced by 20 percent for each subsequent year through 2026. Capital investments placed in service after December 31, 2026, are not eligible for bonus depreciation. See 26 U.S. Code §168(k)(6)(A).

161 *See* Docket No. ER21-1635-000.

on April 28, 2021.[162] The MMU objected to the continued use of the outdated CRF for existing units. The MMU also introduced a CRF formula for calculating the CRF for new black start units and requested that the CRF formula be included in the tariff.[163] [164] On August 10, 2021, FERC issued an order ("August 10th Order") that accepted PJM's tariff revisions that apply to new black start units (selected for service after June 6, 2021) and directed PJM to include the CRF formula proposed by the MMU.[165] The August 10th Order also established a show cause proceeding in a new docket to "determine whether the existing rates for generating units providing Black Start Service (Black Start Units), which are based on a federal corporate income tax that pre-dates the Tax Cuts and Jobs Act of 2017 (TCJA), remains just and reasonable."[166] The MMU requested rehearing over the Commission's conclusion that the MMU had requested "retroactive changes to the rates previously paid to generators."[167] [168] The request for rehearing was denied.[169] PJM's compliance filing to address the August 10 Order was accepted by letter order, subject to edits proposed by the MMU, on December 16, 2021.[170]

PJM's response to the show cause directive in the August 10th Order continued to support the use of the outdated CRF despite the Commission's statement that the CRF values "appear to be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful."[171] [172] The MMU responded with analysis showing that PJM's proposal for maintaining the outdated CRF values would result in significant over recovery of black start capital investments.[173] In March 2023, FERC issued an order establishing hearing and settlement judge procedures.[174] Settlement talks continued and in January 2024 Commission Trial Staff moved to suspend the proceeding because a settlement had been reached in principle.[175] The MMU filed comments in opposition to the settlement, and the settlement was not certified to the Commission.[176] [177] The hearing process then resumed, but rather than hold a hearing, PJM, with the support of FERC Staff, submitted a second offer of settlement on behalf of itself and certain black start unit owners, AMP, ODEC and the PJM ICC. The settlement included exactly the same values as the first settlement, but also included affidavits. By order issued September 23, 2025, the Commission approved the second offer of settlement over the MMU's objection.[178] Forty-nine black start generators received payments based on the outdated CRF. All but eight of the 49 generators have completed their black start capital cost recovery terms.

The November 15, 2024, settlement reduced the capital recovery payments for 38 black start generators. Table10-57 shows the new CRF values from the settlement. The settlement CRF values became effective on January 1, 2024.

Table 10-57 Settlement CRF Values

Capital Recovery Period (years)	Original CRF Value	November 2024 Settlement CRF Value
5	0.363	0.310
10	0.198	0.177
15	0.146	0.135
20	0.125	0.118

There is no financial basis for the settlement CRF values and the settlement will result in significant over recovery for the owners of the black start generators. The settlement reduced the excess recovery payments from $89.7 million to $74.1 million. FERC never made a determination in the show cause proceeding (EL21-91) regarding the "just and reasonableness" of continuing to pay the existing resources at an outdated CRF based on an income tax rate that is no longer in effect. This question remains outstanding today and a similar over or under recovery issue will arise if there is a significant change in a state or federal income tax rate.

162 See Comments of the Independent Market Monitor for PJM, FERC Docket No. ER21-1635-000 (April 28, 2021).
163 See Answer and Motion for Leave to Answer of the independent Market Monitor for PJM, ER21-1635 (May 20, 2021).
164 See Comments of the Independent Market Monitor for PJM, FERC Docket No. ER21-1635 (July 2, 2021).
165 See 176 FERC ¶ 61,080 at 42 and 44 (2021).
166 176 FERC ¶ 61,080 at 2 (2021).
167 *Id.* at 50.
168 Request for Rehearing of the Independent Market Monitor for PJM, FERC Docket No. ER21-1635 (September 9, 2021).
169 See 177 FERC ¶ 62,017 (2021).
170 See 177 FERC ¶ 61,202 (2021).
171 *PJM Interconnection, L.L.C., Response to Commission's Show Cause Order*, Docket No. EL21-91 (October 12, 2021).
172 August 10th Order at 47.
173 Errata Filing of the Independent Market Monitor for PJM, Attachment B at 17, Docket No. EL21-91 (November 18, 2022).
174 See 182 FERC ¶ 61,194.
175 Motion of Commission Trial Staff to Suspend Procedural Schedule and Shorten Answer Period, Docket No. EL21-91-003 (January 10, 2024).
176 Comments of the Independent Market Monitor for PJM in Opposition to Offer of Settlement, Docket No. EL21-91-000, -003 (February 20, 2024).
177 186 FERC ¶ 63,019 (2024).
178 See 193 FERC ¶ 61,059.

On July 4, 2025, with the enactment of the One Big Beautiful Bill Act ("OBBBA"),[179] the bonus depreciation rules changed again. Section 70301 of OBBBA (I.R.C. § 168(k)) allows 100 percent bonus depreciation for "qualified production property ("QPP") acquired and placed in service on or after January 20, 2025.[180] QPP means nonresidential real property used in manufacturing, production, or refining of tangible personal property in the United States.[181] To be eligible, construction must begin after January 19, 2025, and before January 1, 2029, and the property must be placed in service before January 1, 2031.[182]

The CRF value, once it has been assigned to a generator, should not be updated unless there is a significant change in the state or federal income tax rate.[183] PJM currently updates the CRF for generators that have already begun receiving capital recovery payments anytime the debt rate changes. This is not correct. The debt rate reflects the market conditions during the year the investment is placed into service. A change in the debt rate in a subsequent year is not relevant to the capital cost recovery, and will lead to an over or under recovery. This is not how the MMU intended for the CRF formula to be utilized. This is another negative consequence of the show cause procedure (EL21-91) being passed to hearing and settlement without resolution. A process needs to be included in Schedule 6A that specifies how and when to update the CRF value for a generator that has already been assigned a CRF and begun capital cost recovery. The formula and parameter values currently in Schedule 6A are for determining the initial capital recovery payment. To correctly update a CRF for a generator that is already receiving capital recovery payments, the outstanding capital investment must be determined and a new CRF calculated based on the updated parameter values and the years remaining in the capital recovery period.

179 Also known as the 2025 Reconciliation Bill and Public Law 119-21.
180 OBBBA § 70301(c)(1).
181 OBBBA § 70307(a)(2).
182 *Id.*
183 Because PJM rounds CRF to 3 digits, a "significant change" is one that changes the CRF by ± 0.001.

Reactive Service and Capability

Under Schedule 2 to the OATT, suppliers of reactive power have been compensated separately for both reactive service and reactive capability.[184] [185] [186] [187]

On October 17, 2024, the Commission issued a final rule, Order No. 904, eliminating separate payments for reactive in all jurisdictional markets, including PJM.[188] On January 28, 2025, PJM submitted a compliance filing to implement Order No. 904 ("Compliance Filing").[189] The Compliance Filing proposed a transition mechanism lasting through May 31, 2026. On August 4, 2025, the Commission accepted PJM's termination of separate Schedule 2 payments after May 31, 2026, but rejected PJM's proposed transition mechanism and the MMU's proposed enhancements to that mechanism.[190] The current rules apply until payments under Schedule 2 terminate.

Reactive Costs

Customers in PJM paid total reactive capability charges of $85.6 million in the first three months of 2026. Under the current rules, effective through May 31, 2026, compensation for reactive capability is approved separately for each resource or resource group by FERC per Schedule 2 of the OATT.[191] Reactive capability credits are based on FERC approved filings for individual unit revenue requirements that are typically black box settlements.[192] Reactive service credits are paid to units that operate in real time outside of their normal range at the direction of PJM for the purpose of providing reactive

184 See Monitoring Analytics, LLC, *2024 Quarterly State of the Market Report for PJM: January through September* (November 14, 2024) at 652–656, for history and analysis of reactive power in PJM.
185 See Order No. 2003, 104 FERC ¶ 61,103 at P 544 (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); *CAISO*, 160 FERC ¶ 61,035 at P 19 (2017); *SPP*, 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).
186 See OATT Attachment O.
187 See *MISO*, 182 FERC ¶ 61,033 at P 52 (January 27, 2023) (*MISO*); *see also Standardization of Generator Interconnection Agreements & Procedures*, Order No. 2003, 104 FERC ¶ 61,103 at P 546.
188 See *Compensation for Reactive Power within the Standard Power Factor Range*, Order No. 904, 189 FERC ¶ 61,034 ("Order No. 904").
189 See Docket No. ER25-1073.
190 See 192 FERC ¶ 61,113; see also, Comments of the Independent Market Monitor for PJM, Docket No. ER25-1073 (February 18, 2025).
191 See "PJM Manual 27: Open Access Transmission Tariff Accounting," § 3.2 Reactive Supply and Voltage Control Credits, Rev. 102 (Jan. 23, 2025); 192 FERC ¶ 61,113 (2025).
192 See OATT Schedule 2.

service. Compensation for reactive power service is based on real-time lost opportunity costs.[193]

Total reactive capability charges are the sum of FERC approved reactive supply revenue requirements. Zonal reactive supply revenue requirement charges are allocated monthly to PJM customers based on their zonal and to any nonzonal (outside of PJM) peak transmission use and daily average point to point transmission reservations.[194] [195]

In the first three months of 2026, total reactive charges were $85.7 million, a decrease of $6.5 million (7.1 percent) from the first three months of 2025. In the first three months of 2026, total reactive capability charges were $85.6 million, a decrease of $6.1 million (6.7 percent) from the first three months of 2025. In the first three months of 2026, total reactive service charges were $0.1 million, a decrease of $0.4 million (77.0 percent) from the first three months of 2025. Total zonal reactive service charges ranged from $0 in the REC and OVEC Zones, to $13.8 million in the AEP Zone in the first three months of 2025.

Table 10-58 shows reactive service charges for January through March of each year from 2010 through 2026.

Table 10-58 Reactive service charges and reactive capability charges: January through March, 2010 through 2025

Jan-Mar	Reactive Service Charges	Reactive Capability Charges	Total
2010	$1,462,979	$60,140,250	$61,603,229
2011	$7,901,985	$61,525,380	$69,427,366
2012	$22,774,605	$68,171,375	$90,945,980
2013	$55,579,356	$68,330,702	$123,910,058
2014	$7,589,161	$70,631,766	$78,220,927
2015	$6,330,318	$69,482,495	$75,812,813
2016	$250,496	$72,742,919	$72,993,415
2017	$5,872,960	$75,383,924	$81,256,884
2018	$6,054,364	$74,884,662	$80,939,026
2019	$124,821	$80,560,451	$80,685,272
2020	$45,745	$85,354,846	$85,400,591
2021	$705,618	$89,123,265	$89,828,883
2022	$231,202	$95,355,371	$95,586,572
2023	$0	$95,904,368	$95,904,368
2024	$892,690	$94,627,077	$95,519,767
2025	$522,553	$91,656,198	$92,178,751
2026	$119,852	$85,551,307	$85,671,159

Table 10-59 shows zonal reactive service charges, reactive capability charges and total charges for the first three months of 2025 and 2026. Reactive service charges show charges to each zone for reactive service. Reactive capability charges show charges to each zone for reactive capability.

193 See OA Schedule 1 § 3.2.3B.
194 OATT Schedule 2.
195 See "PJM Manual 27: Open Access Transmission Tariff Accounting," § 3.3 Reactive Supply and Voltage Control Charges, Rev. 102 (Jan. 23, 2025).

Table 10-59 Reactive service charges and reactive capability charges by zone: January through March, 2025 and 2026

	Jan-Mar 2025			Jan-Mar 2026		
Zone	Reactive Service Charges	Reactive Capability Charges	Total Charges	Reactive Service Charges	Reactive Capability Charges	Total Charges
ACEC	$0	$448,441	$448,441	$0	$359,085	$359,085
AEP	$0	$14,289,629	$14,289,629	$0	$13,796,417	$13,796,417
APS	$6,825	$4,971,593	$4,978,418	$0	$4,421,221	$4,421,221
ATSI	$0	$6,256,994	$6,256,994	$0	$5,882,823	$5,882,823
BGE	$0	$1,616,939	$1,616,939	$0	$855,315	$855,315
COMED	$0	$12,108,885	$12,108,885	$71,282	$11,351,515	$11,422,797
DAY	$0	$685,731	$685,731	$0	$668,927	$668,927
DUKE	$0	$1,948,686	$1,948,686	$0	$1,723,691	$1,723,691
DOM	$0	$11,326,226	$11,326,226	$0	$10,489,103	$10,489,103
DPL	$505,276	$2,369,747	$2,875,023	$45,133	$2,361,144	$2,406,278
DUQ	$0	$19,734	$19,734	$0	$19,914	$19,914
EKPC	$0	$530,918	$530,918	$0	$535,758	$535,758
JCPLC	$0	$1,332,739	$1,332,739	$0	$1,344,890	$1,344,890
MEC	$5,204	$1,420,616	$1,425,819	$0	$1,090,345	$1,090,345
OVEC	$0	$0	$0	$0	$0	$0
PECO	$0	$5,014,629	$5,014,629	$0	$5,001,619	$5,001,619
PE	$0	$3,060,796	$3,060,796	$0	$3,021,319	$3,021,319
PEPCO	$5,249	$2,006,980	$2,012,229	$0	$2,025,277	$2,025,277
PPL	$0	$8,718,893	$8,718,893	$3,436	$8,211,121	$8,214,558
PSEG	$0	$6,565,087	$6,565,087	$0	$6,616,234	$6,616,234
REC	$0	$0	$0	$0	$0	$0
(Imp/Exp/Wheels)	$0	$6,962,935	$6,962,935	$0	$5,775,589	$5,775,589
Total	$522,553	$91,656,198	$92,178,751	$119,852	$85,551,307	$85,671,159

Table 10-60 shows the units which received reactive service credits in the first three months of 2026.

Table 10-60 Reactive service credits by plant (Total dollars): January through March, 2026

	Jan-Mar 2026	
Zone	Plant	Reactive Service Credits
COMED	COM 11 FISK 32 CT	$71,282
DPL	DPL COMM CHESAPEAKE - NEW CHURCH 3 CT	$45,133
PPL	PL HAZELTON 2 CT	$1,194
PPL	PL HAZELTON 3 CT	$1,157
PPL	PL HAZELTON 4 CT	$1,085

Table 10-61 shows the settled reactive capability revenue requirements by technology effective on March 1, 2026, for active units.[196] These revenue requirements do not include revenue requirements that were filed but not yet final. The table demonstrates the wide disparity in payments for reactive capability that result from the current cost of service rate case model settlement process.

196 The total amount in the final row of Table10-24 is the amount that would be paid if the total rate effective on March 1, 2026, were effective for an entire year. The total rates effective on any given day depend on requests made by resource owners in filings to FERC and FERC approval of those rates.

Table 10-61 Total settled reactive revenue requirements by unit type and fuel type for active units[197]: March 1, 2026

Unit Type	Fuel Type	Total Revenue Requirement per Year	MW	Number of Resources	Revenue Requirement per MW-year	Minimum Revenue Requirement per MW-year	Maximum Revenue Requirement per MW-year
CC	Gas	$122,213,638.36	48,906.6	152	$371,800.95	$302.10	$22,500.00
CT	Gas	$44,998,557.53	27,734.0	245	$531,994.39	$103.64	$19,610.84
CT	Oil	$4,034,823.25	2,714.9	98	$143,701.18	$289.74	$4,052.58
Diesel	Oil	$839,703.17	145.3	31	$183,630.75	$395.37	$8,812.75
Diesel	Other - Gas	$1,117,240.13	102.6	12	$118,519.87	$3,984.09	$13,468.38
FC	Gas	$45,000.00	2.3	1	$19,565.22	$19,565.22	$19,565.22
Hydro	Water	$24,401,850.45	6,676.3	53	$254,134.36	$126.37	$23,996.44
Nuclear	Nuclear	$68,243,063.20	32,530.9	31	$75,841.24	$807.91	$7,140.45
Solar	Solar	$4,572,620.48	1,466.9	13	$77,386.09	$705.15	$15,007.81
Steam	Coal	$45,956,273.10	34,811.2	56	$128,165.58	$255.85	$9,804.78
Steam	Gas	$5,801,349.66	5,725.3	17	$19,869.70	$626.53	$3,737.86
Steam	Oil	$2,486,051.94	1,499.3	6	$10,944.78	$1,262.01	$3,211.11
Steam	Other - Solid	$340,000.00	34.0	2	$18,919.11	$8,311.11	$10,608.00
Steam	Wood	$330,830.32	153.0	3	$6,486.87	$2,162.29	$2,162.29
Wind	Wind	$17,987,594.17	4,877.4	38	$154,123.83	$1,860.80	$9,564.74
All		$343,368,595.75	167,380.0	758	$2,051.43	$103.64	$23,996.44

Frequency Control

There are four distinct types of frequency control, distinguished by response timeframe and operational nature: Inertial Response, Primary Frequency Response, Secondary Frequency Control (Regulation), and Tertiary Frequency Control (Primary Reserve).

- **Inertial Response.** Inertial response to frequency excursion is the natural resistance of rotating mass turbine generators to changes in their stored kinetic energy. This response is immediate and resists short term changes to ACE from the instant of the disturbance up to twenty seconds after the disturbance.
- **Primary Frequency Response.** Primary frequency response is a response to a disturbance based on a local detection of frequency and local operational control settings. 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.
- **Secondary Frequency Control.** Secondary frequency control is called regulation. In PJM it begins to respond within 10 to 15 seconds and can continue up to an hour. Regulation is controlled by PJM which detects the grid frequency, calculates a counterbalancing signal, and transmits that signal to all regulating resources.
- **Tertiary Frequency Control.** Tertiary frequency control and imbalance control lasting 10 minutes to an hour is called primary reserve.

197 For aggregate requirements, in which a single payment is made for the combined output of multiple units, the aggregate requirement was distributed in proportion to unit size for calculating a resource's individual revenue requirement. For wind, solar, and hydro resources, that size is the ELCC. For all other resources, that size is the ICAP.

Primary Frequency Response

Primary Frequency Response ("PFR") is achieved through the use of automatic governors installed on generators. A governor can be either an electronic or mechanical device that increases or decreases a generator's output based on frequency changes in the system. Governors are set to respond to any frequency changes larger than a defined minimum, called a deadband, which is expressed in Hertz (Hz). Governors have a frequency change limit, called droop, which is expressed as a percentage of the frequency change from the optimal 60 Hz (e.g. 2 percent droop equals 0.02 * 60 Hz, or 1.2 Hz). Governor droop changes resource output in proportion to the deviation of frequency once frequency has exceeded the deadband limit. Primary frequency response alone does not restore frequency to the original scheduled value primarily because governor directed changes only occur when frequency is beyond the governor deadband.

On February 15, 2018, the Commission issued Order No. 842, which modified the pro forma large and small generator interconnection agreements and procedures to require all newly interconnecting non nuclear generating facilities, both synchronous and nonsynchronous, to include equipment for primary frequency response capability as a condition to receive interconnection service. Such equipment must include a governor or equivalent controls with the capability of operating at a maximum five percent droop and ±0.036 Hz deadband (or the equivalent or better).[198] PJM filed revisions in compliance with Order No. 842 that substantively incorporated the pro forma agreements into its market rules.[199]

PJM evaluates generators' primary frequency capabilities using two to three frequency events per month, with events being chosen based on the criteria that the frequency stays outside ±0.040 Hz deadband for at least one minute, and the minimum/maximum frequency reaches ±0.053 Hz. Nuclear units, offline units, units with no available headroom/footroom, units assigned regulation, and units with an active eDART ticket for governor outage are not evaluated. The performance of each unit is evaluated, with each event evaluated separately with a responsive/non-responsive pass/fail determination, and then averaged quarterly. A quarterly unit performance of 50 percent or greater is considered responsive.[200]

There are several current issues with PJM's enforcement and evaluation of generations PFR requirements. Despite the 2018 FERC order, PJM has not maintained an accurate, up to date list of all units subject to evaluation. This means that as new units have come online (since approximately 2020), they are not being tested at all during the monthly frequency events. In addition, PJM does not currently have an objective metric to determine what response constitutes a unit passing a test during these frequency events. Instead, the telemetric response of each unit is compared to the frequency conditions during an event, and a judgement is made as to whether or not the unit has adequately responded. Further, this underlying unit data and results of these primary frequency response events are not saved in PJM's databases, so the MMU is not currently able to verify the results of these tests. In the event of a unit's noncompliance, PJM does not have a defined penalty and remediation process.

The MMU recommends that PJM update and maintain a full list of generation resources required to provide PFR, save all of the results and underlying data associated with testing PFR capabilities, develop the metric(s) necessary to objectively evaluate each unit's PFR during events, and create the necessary tariff/manual language to properly enforce the NERC mandated requirements.

The MMU is working with PJM to update PJM's list of units that are subject to evaluation and to develop a set of metrics for monitoring compliance and measuring performance by units subject to Order No. 842.

The MMU recommends that the same capability be required of both new and existing resources. The MMU agrees with Order No. 842 that RTOs not be required to provide additional compensation specifically for frequency response. The current PJM market design provides the ability to cover all costs, including these. The current market design provides compensation, through heat rate adjusted energy offers, for any costs associated with providing

198 See 157 FERC ¶ 61,122 (2016).
199 See 164 FERC ¶ 61,224 (2018).
200 See PJM Manual 12: Balancing Operations, § 3.6.2. Rev. 56 (October 1, 2025).

frequency response. PJM rules appropriately require frequency response as a condition to receive interconnection service.[201]

On August 15, 2024, NERC proposed Project 2020-02, a modification to the PRC-029-1 reliability standard, called, “The frequency and voltage ride through requirement for inverter based generating resources (“IBRs”).” This proposed standard is intended to address the risk to reliability associated with the rapid adoption of IBRs, by requiring that Category 2 Generator Owner and Generator Operator (“Category 2 GO/GOP”) IBRs remain operational during and after defined frequency and voltage excursions.[202] [203] To achieve this, IBRs must continue to deliver predisturbance levels of active and reactive power, and would only be permitted to trip to avoid equipment damage. This proposal was adopted by the NERC board on October 8, 2024.[204] NERC is currently working with the regional entities to register IBRs, with an effective registration date of May 15, 2026.[205] PJM has identified and submitted to NERC a list of 50 units that meet the criteria for Category 2 GO/GOP IBRs.

201 See 164 FERC ¶ 61,224 at P 2 (2018).
202 “Category 2 GO/GOP,” is defined as Generator Owners and Generator Operators that, “...own or operate IBRs that: (i) either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, and (ii) are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.” See NERC, “North American Electric Reliability Corporation Inverter-Based Resources Work Plan Progress Update,” <https://www.nerc.com/FilingsOrders/us/NERC Filings to FERC DL/IBR Work Plan Filing_May Update_signed.pdf> (Accessed November 7, 2025)
203 See NERC, “PRC-029-1,” <https://www.nerc.com> (Accessed November 6, 2024).
204 See NERC, “Project 2020-02 Modifications to PRC-024 (Generator Ride-through),” <https://www.nerc.com/pa/Stand/Pages/Project_2020-02_Transmission-connected_Resources.aspx> (Accessed August 7, 2025).
205 See NERC, “North American Electric Reliability Corporation Inverter-Based Resources Work Plan Progress Update,” <https://www.nerc.com/FilingsOrders/us/NERC Filings to FERC DL/IBR Work Plan Filing_October 2025 Update_signed.pdf> (Accessed October 31, 2025).

11 Congestion and Marginal Losses

When there are binding transmission constraints and locational price differences, load pays more for energy than generation is paid to produce that energy.[1] The difference is congestion.[2] As a result, congestion belongs to load and should be returned to load. Congestion is not the difference in CLMP between nodes. Congestion is not the billing line item labeled congestion.[3]

Congestion is not a useful metric for determining whether there is a benefit to building more transmission. Analyses that use congestion to support the need for transmission expansion incorrectly count congestion as a cost to load without accounting for how the congestion dollars are or are not returned to the load through ARRs and FTRs.

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 can actually increase when the transmission capacity between areas with lower cost generation and areas with higher cost generation is expanded 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 can be 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 cost/benefit 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. There clearly can be benefits to transmission expansion but congestion is not the correct metric for measuring those benefits. The correct metric is the change in production costs which measures the reduction in the reliance on higher cost generation to meet load in the presence of a transmission constraint.

This issue also illustrates the unintended and negative consequences of misunderstanding congestion and FTRs. The unintended result is to overstate the benefits of transmission expansion by not correctly recognizing how congestion dollars should be returned to load. Even in the case where there is only a partial return of congestion to load, the actual return of congestion to load must be accounted for in order to correctly identify the benefits. Ignoring the return of congestion to load from ARRs/FTRs overstates the potential benefits of transmission expansion, and ignores the value of smaller upgrades that may not eliminate a constraint, but may reduce production costs and therefore the average cost of energy for load.

The locational marginal price (LMP) is the incremental price of energy at a bus. The LMP at a bus can be divided into three components: the system marginal price (SMP) or energy component, the congestion component (CLMP), and the marginal loss component (MLMP). SMP, MLMP and CLMP are the simultaneous products of the least cost, security constrained dispatch of system resources to meet system load and the use of a load-weighted reference bus. The relative values of SMP and CLMP are arbitrary and depend on the reference bus.

SMP is defined as the incremental price of energy for the system, given the current dispatch, at the load-weighted reference bus, or LMP net of losses and congestion. SMP is the LMP at the load-weighted reference bus. The load-weighted reference bus is not a fixed location but varies with the distribution of load at system load buses. For SMP, energy means the component of LMP not associated with a binding transmission constraint. All other locational prices that result from the least cost, security constrained market solution are higher or lower than this reference point price (SMP) as a result of binding constraints. The reference bus is a point of reference. For a given market solution, changing the reference bus does not change the LMP for any node on the system, but changes only the elements of the nodal prices that are positive or negative due to the binding constraints in that solution, further illustrating that the relative levels of SMP and LMP are arbitrary.

1 Load is generically referred to as withdrawals and generation is generically referred to as injections, unless specified otherwise.
2 The difference in losses is not part of congestion.
3 PJM billing examples can be found in *2019 Annual State of the Market Report for PJM*, Appendix F: Congestion and Marginal Losses.

CLMP is defined as the incremental price of meeting load at each bus when a transmission constraint is binding, based on the shadow price associated with the relief of a binding transmission constraint in the security constrained optimization. (The shadow price is the difference between the CLMPs across the transmission constraint.) There can be multiple binding transmission constraints. CLMPs are positive or negative depending on location relative to binding constraints and relative to the load-weighted reference bus. In an unconstrained system CLMPs will be zero. This means that CLMP at a bus is not congestion. The difference between CLMPs at buses is not congestion, it is just the absolute LMP difference between the two buses caused by transmission constraints, or the shadow price. CLMP is the portion of the LMP at a bus that indicates whether the LMP at that bus is higher or lower than the marginal price of energy SMP at the selected reference bus due to binding transmission constraints. The relative values of SMP and CLMP are arbitrary and depend on the reference bus.

MLMP is defined as the incremental price of losses at a bus, based on marginal loss factors in the security constrained optimization. Losses refer to energy lost to physical resistance in the transmission network as power is moved from generation to load.

Total losses refer to total system wide transmission losses as a result of moving power from injections to withdrawals on the system. Marginal losses are the incremental change in system losses caused by changes in load and generation.

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.[4] When the least-cost available energy cannot be delivered to load in a transmission constrained area, higher cost units in the constrained area must be dispatched to meet that load. The result is that the price of energy in the constrained area is higher than in the unconstrained area because of the combination of transmission limitations and the cost of local generation. Congestion is the difference between the total cost of energy paid by load in the transmission constrained area based on the single higher price at load buses and the total revenue received by generation based on the prices at the generator buses to provide that energy, after virtual bids have been settled. Congestion equals the sum of day-ahead and balancing congestion. The actual incremental cost paid by load in the constrained area is the difference in price (shadow price) times the MW of load served by higher cost local generation. This is also the higher production costs that result from the constraint.

The energy, marginal losses and congestion metrics must be interpreted carefully.

In PJM accounting, the term total congestion refers to net implicit CLMP charges plus net explicit CLMP charges plus net inadvertent CLMP charges. The net implicit CLMP charges are the implicit withdrawal CLMP charges less implicit injection CLMP credits.

As with congestion, total system energy costs are more precisely termed net system energy costs and total marginal loss costs are more precisely termed net marginal loss costs. Ignoring interchange, total generation MWh must be greater than total load MWh in any hour in order to provide for losses. Since the hourly integrated energy component of LMP is the same for every bus within every hour, the net energy bill is negative (ignoring net interchange), with more generation credits than load payments in every hour.[5]

While PJM accounting focuses on CLMPs, the individual CLMP values at any bus are irrelevant to the calculation of congestion, as CLMPs are just an artificial deconstruction of LMP based on a selected reference bus. Holding aside the marginal loss component of LMP, differences in the LMPs are caused by binding constraints in the least cost security constrained dispatch

4 This is referred to as dispatching units out of economic merit order. Economic merit order is the order of all generator offers from lowest to highest cost. Congestion occurs when loadings on transmission facilities mean the next unit in merit order cannot be used and a higher cost unit must be used in its place. Dispatch within the constrained area follows merit order for the units available to relieve the constraint.

5 The total congestion and marginal losses for 2026 were calculated as of April 19, 2026, and are subject to change, based on continued PJM billing updates.

market solution and total congestion is the net surplus revenue that remains after all sources and sinks are credited or charged their LMPs. Changing the components of LMP by electing a different reference bus does not change the LMPs or the difference between LMPs for a given market solution, it merely changes the components of the LMP. This means that no particular importance should be assigned to the levels of SMP and CLMP at a bus.

Local congestion is the congestion paid by load at a specific bus or set of buses and is calculated on a constraint specific basis. For a given market solution, a change in the reference bus does not change the LMP at any bus and does not change total congestion paid by load and does not change the local congestion paid by load at a specific location. Holding aside the marginal loss component of LMP, local congestion is the sum of the total LMP charges to load at the defined set of buses minus the sum of the total LMP credits received by all generation that supplied that load, given the set of all binding transmission constraints, regardless of location. Local congestion reflects the underlying characteristics of the complete power system as it affects the defined area, including the nature and 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. Local congestion fully reflects the least cost security constrained system solution and the LMPs that result from that solution.

PJM implemented fast start pricing in both day-ahead and real-time markets starting September 1, 2021. PJM's fast start pricing logic results in pricing run locational marginal prices (PLMP). PLMP is the price that load pays and generators receive in the PJM energy market.

While PLMP is the official settlement price, PJM continues to calculate LMP based on the logic that PJM uses to actually dispatch system resources and used prior to the introduction of fast start to consistently define dispatch and prices. The LMPs from the dispatch run are dispatch run locational marginal prices (DLMP). While the settlement prices are PLMP, settlement MW are based on the dispatch run in the day-ahead market and are metered output in the real-time market.

PJM inappropriately uses artificial constraints in the day-ahead and real-time markets to force specific resources (generation or demand response) to be marginal in order to have those resources set price. The resultant, artificially uniform source dfax and sink dfax of the artificial constraint can be modified, along with the line limits, by PJM to meet market outcome goals and are a source of often significant modeling differences between the day-ahead and real-time market. These modeling differences result in inefficient market outcomes and false arbitrage opportunities for virtual transactions. These artificial constraints have been used to hide uplift costs by making uplift costs negative congestion charges. The use of artificial constraints is an inappropriate use of PJM discretion as the market operator, putting PJM in the position of a market actor, arbitrarily changing market results, market prices, generation revenues, congestion costs and load charges. [6]

Overview

Congestion Cost

- **Total Congestion.** Total congestion costs increased by $1,511.9 million or 300.4 percent, from $503.3 million in the first three months of 2025 to $2,015.2 million in the first three months of 2026.
- **Day-Ahead Congestion.** Day-ahead congestion costs increased by $1,577.2 million or 224.2 percent, from $703.5 million in the first three months of 2025 to $2,280.7 million in the first three months of 2026.
- **Balancing Congestion.** Negative balancing congestion costs increased by $65.3 million, from -$200.2 million in the first three months of 2025 to -$265.5 million in the first three months of 2026. Negative balancing explicit charges decreased by $7.2 million, from -$94.5 million in the first three months of 2025 to -$87.3 million in the first three months of 2026.
- **Real-Time Congestion.** Real-time congestion costs increased by $1,614.0 million, from $854.2 million in the first three months of 2025 to $2,468.2 million in the first three months of 2026.

6 The MMU identified missing and erroneous distribution factors and shadow prices, primarily within the pricing run. The calculation of constraint and zonal based congestion requires accurate distribution factors and shadow prices. Where available, the MMU used distribution factors from the dispatch run. The MMU also calculated missing shadow prices for the relevant transmission constraints when feasible. This approach reduced the impact of the errors. Any remaining errors contributed to the NA component. Figures and tables affected by this error are indicated with a footnote.

- **Monthly Congestion.** Monthly total congestion costs in the first three months of 2026 ranged from $171.4 million in March to $1,205.7 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 Bedington Transformer, the Pruntytown Transformer, the Bedington – Black Oak Interface, the Pruntytown Circuit Breaker, and the Conastone – Northwest Line.
- **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 2026. The number of congestion event hours in the day-ahead energy market was about 2 times the number of congestion event hours in the real-time energy market.

  Day-ahead congestion frequency decreased by 1.2 percent from 20,824 congestion event hours in the first three months of 2025 to 20,569 congestion event hours in the first three months of 2026.

  Real-time congestion frequency increased by 19.6 percent from 8,416 congestion event hours in the first three months of 2025 to 10,069 congestion event hours in the first three months of 2026.
- **Congested Facilities**. Day-ahead, congestion event hours decreased on interfaces and lines and increased on transformers and flowgates.

  The Bedington Transformer was the largest contributor to congestion costs in the first three months of 2026. With $374.7 million in total congestion costs, it accounted for 18.7 percent of the total PJM congestion costs in the first three months of 2026.
- **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 2025 or 2026.
- **Zonal Congestion**. DOM had the highest zonal congestion costs among all control zones in the first three months of 2026. DOM had $356.7 million in zonal congestion costs, comprised of $407.7 million in day-ahead congestion costs and -$51.0 million in balancing congestion costs.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs increased by $431.2 million or 100.5 percent, from $428.9 million in the first three months of 2025 to $860.0 million in the first three months of 2026. The loss MWh in PJM increased by 198.0 GWh or 4.1 percent, from 4,794.8 GWh in the first three months of 2025 to 4,992.8 GWh in the first three months of 2026. The loss component of real-time LMP in the first three months of 2026 was $0.08, compared to $0.04 in the first three months of 2025.
- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs increased by $429.3 million or 95.5 percent, from $449.7 million in the first three months of 2025 to $879.0 million in the first three months of 2026.
- **Balancing Marginal Loss Costs.** Negative balancing marginal loss costs decreased by $1.8 million or 8.9 percent, from -$20.8 million in the first three months of 2025 to -$19.0 million in the first three months of 2026.
- **Total Marginal Loss Surplus.** The total marginal loss surplus increased by $165.2 million or 105.1 percent, from $157.3 million in the first three months of 2025, to $322.5 million in the first three months of 2026.
- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in the first three months of 2026 ranged from $94.3 million in March to $517.4 million in January.

System Energy Cost

- **Total System Energy Costs.** Total system energy costs decreased by $267.1 million or 98.6 percent, from -$270.9 million in the first three months of 2025 to -$538.0 million in the first three months of 2026.
- **Day-Ahead System Energy Costs.** Day-ahead system energy costs decreased by $277.7 million or 90.3 percent, from -$307.5 million in the first three months of 2025 to -$585.2 million in the first three months of 2026.

- **Balancing System Energy Costs.** Balancing system energy costs decreased by $1.0 million or 2.7 percent, from $39.0 million in the first three months of 2025 to $38.0 million in the first three months of 2026.
- **Monthly Total System Energy Costs.** Monthly total system energy costs in the first three months of 2026 ranged from -$323.8 million in January to -$59.6 million in March.

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.

The current ARR/FTR design should ensure but 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 2025/2026 planning period was 55.3 percent. The cumulative offset of congestion by ARRs for the 2011/2012 planning period through the first ten months of the 2025/2026 planning period, using the rules effective for each planning period, was 66.0 percent. Load has received $6.8 billion less than load should have received from the 2011/2012 planning period through the first ten months of the 2025/2026 planning period.

Issues

Artificial Constraints, Closed Loop Interfaces and CT Pricing Logic

PJM has used, and in some cases, continues to use, artificial constraints in the day-ahead and real-time markets to force specific resources (generation or demand response) to be marginal in order to have those resources set price. Some of these artificial constraints, such as CT pricing logic and closed loop interfaces, result in negative congestion charges that are an artifact of the artificial nature of the constraints that cause generation to be paid more than load pays for energy affected by the constraint. PJM also makes use of artificial constraints that function like closed loop interfaces but which result in positive or negative balancing congestion. These constraints are called Real-Time Short-Term Marginal Value Overrides. These constraints are similar to a closed loop interface in that they enforce artificially uniform price effects, but unlike closed loop interfaces that only affect prices on the constrained side, these artificial constraints enforce artificially uniform price spreads between the two sides of the constraint through large uniform dfax on the constrained side and small uniform dfax on the unconstrained side. These artificial constraints take the form of interfaces or enforced contingencies (modifications) on existing constraints. The uniform source dfax and uniform sink dfax of the artificial constraint can be modified, along with the transmission line limits, by PJM to meet market outcome goals and are a source of often significant modeling differences between the day-ahead and real-time market. These modeling differences result in inefficient market outcomes and false arbitrage opportunities for virtual transactions. This is an inappropriate use of these tools as it puts PJM in the position of a market actor, arbitrarily changing market results, market prices, generation revenues, congestion costs and load charges. One of the side effects of these changes in parameters, besides causing modeling differences between the day-ahead and real-time market, is that the apparent location of the interface or parent constraint can move intraday relative to source and sink points.

While CT pricing logic was officially discontinued by PJM with the implementation of fast start pricing on September 1, 2021, PJM continues to use the same basic logic (Real-Time Short-Term Marginal Value Overrides) to force inflexible units to be on the margin in both real time and day ahead. PJM used CT pricing logic to force otherwise uneconomic resources to be marginal and set price in the day-ahead or real-time market solution. PJM used CT pricing logic to create an artificial constraint with a variable flow limit, paired with an artificial override of the inflexible resource's economic minimum, to make the resource marginal in PJM's LMP security constrained pricing logic. The purpose of forcing inflexible units to be marginal is to artificially reduce the uplift associated with the dispatch of inflexible resources.

Through the assumption of artificial flexibility of the affected unit and artificially creating a constraint for which the otherwise inflexible resource can be marginal, PJM's use of CT pricing logic forced the affected resource bus LMP to match the marginal offer of the resource. PJM adjusts the constraint limit based on the output of the resource. Sometimes the constraint limit does not match the flows on the constraint, and the constraint violates instead of binding, resulting in prices set by the transmission constraint penalty factor.

In the case of a closed loop interface, all buses within the interface were modeled with a distribution factor (dfax) of 1.0 to the constraint and therefore with the same constraint related congestion component of price at the marginal resource's bus. In the CT pricing logic case, the constraint affected the CLMP of constrained side buses in proportion to their dfax to that constraint.[7] One objective of making inflexible resources marginal was to artificially minimize the uplift costs associated with the inflexible resources that PJM commits for system security reasons.

The use of artificial constraints was and is a source of modeling differences between the day-ahead and real-time markets. When artificial constraints are not included in the day-ahead market in exactly the same way as in the real-time market, including specific constraints and limits, the differences between the day-ahead and real-time market model result in positive or negative balancing congestion.

Failure to model the same constraints in the day-ahead and real-time markets results in pricing and congestion settlement differences between the day-ahead and real-time market. Any modeling differences create false arbitrage opportunities for virtual bids and contribute to negative balancing congestion.

Use of artificial constraints, closed loop interfaces and CT price setting logic requires manipulation of the economic dispatch model. Closed loop interfaces and CT price setting logic, like fast start pricing logic that replaced it, force higher cost inflexible units to be marginal.

Like closed loop interfaces and CT pricing logic, some of the artificially enforced constraint results in negative congestion. As a result, more power is produced in the artificial closed loop or constrained area than would result without the artificial constraint. This means that there are more generation credits than load charges in the constrained area. The constrained area exports power, the lower cost generators outside the constrained area are backed down and prices are lower outside the constrained area as a result. All of the generation within the artificially constrained area is paid the higher CLMP, but only a smaller amount of load (in some cases no load) in the constrained area pays this higher CLMP. As a result, load pays less than generation receives in the artificially constrained area. This difference is negative congestion. In the day-ahead market this reduces the total congestion dollars that are available to FTR holders. In the balancing market these costs are allocated directly to load as negative balancing charges.

7 The constrained side means the higher priced side with a positive CLMP created by the constraint.

Locational Marginal Price (LMP)

Components

PJM uses a distributed load reference bus. With a distributed load reference bus, the energy component of LMP is a load-weighted system price. Some price effects of binding constraints may be included in the load-weighted reference bus price.

LMP at a bus reflects the incremental price of energy at that bus. LMP at any bus can be disaggregated into three components: the system marginal price (SMP), marginal loss component (MLMP), and congestion component (CLMP).

SMP, MLMP and CLMP are a product of the least cost, security constrained dispatch of system resources to meet system load. SMP is the incremental cost of system energy, given the current dispatch and given the choice of reference bus. SMP is LMP net of losses and congestion. Losses refer to energy lost to physical resistance in the transmission and distribution network as power is moved from generation to load. Marginal losses are the incremental change in system power losses caused by changes in the system load and generation patterns.[8] The first derivative of total losses with respect to the power flow is marginal losses. Congestion cost reflects the incremental cost of relieving transmission constraints while maintaining system power balance. Congestion

8 For additional information, see the *MMU Technical Reference for PJM Markets,* at "Marginal Losses," <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

occurs when available, least-cost energy cannot be delivered to all loads because transmission facilities are not adequate to deliver that energy. When the least-cost available energy cannot be delivered to load in a transmission constrained area, higher cost units in the constrained area must be dispatched to meet that load.[9] The result is that the price of energy in the constrained area is higher than in the unconstrained area because of the combination of transmission limitations and the cost of local generation. Load in the constrained area pays the higher price for all energy including energy from low cost generation and energy from high cost generation. Congestion is the difference between the total cost of energy paid by load in the transmission constrained area and the total revenue received by generation to meet the load in the transmission constrained area, net of losses. Congestion equals the sum of day-ahead and balancing congestion.

Table 11-1 shows the PJM real-time load-weighted average LMP components for January through March, 2008 through 2026.[10]

The real-time load-weighted average LMP increased by $35.37 or 67.8 percent from $52.20 in the first three months of 2025 to $87.57 in the first three months of 2026. The real-time load-weighted average congestion component was $0.24 in the first three months of 2026, compared to $0.13 in the first three months of 2025. The real-time load-weighted average loss component in the first three months of 2026 was $0.08, compared to $0.04 in the first three months of 2025. The real-time load-weighted average system energy component increased by $35.21 or 67.7 percent from $52.03 in the first three months of 2025 to $87.24 in the first three months of 2026. Using a load-weighted reference bus, the real-time load-weighted average congestion component of LMP should be zero. PJM's load-weighted reference bus congestion component is zero at the time that LMPs are set based on state estimator data. Metering updates during the settlement process change the load weights after the fact, but the reference bus price (SMP) is not updated with these changes over time. As a result, the average congestion and loss components used in real-time settlement are not zero.

Table 11-1 Real-time load-weighted average LMP components (Dollars per MWh): January through March, 2008 through 2026[11]

(Jan - Mar)	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2008	$69.35	$69.27	$0.04	$0.04
2009	$49.60	$49.51	$0.05	$0.04
2010	$45.92	$45.81	$0.06	$0.05
2011	$46.35	$46.30	$0.03	$0.03
2012	$31.21	$31.18	$0.02	$0.00
2013	$37.41	$37.37	$0.02	$0.02
2014	$92.98	$93.08	($0.13)	$0.03
2015	$50.91	$50.89	($0.00)	$0.03
2016	$26.80	$26.75	$0.03	$0.01
2017	$30.28	$30.25	$0.02	$0.02
2018	$49.45	$49.39	$0.03	$0.03
2019	$30.16	$30.12	$0.02	$0.02
2020	$19.85	$19.83	$0.01	$0.01
2021	$30.84	$30.79	$0.03	$0.02
2022	$54.13	$54.03	$0.06	$0.04
2023	$30.28	$30.23	$0.02	$0.02
2024	$31.01	$30.92	$0.06	$0.02
2025	$52.20	$52.03	$0.13	$0.04
2026	$87.57	$87.24	$0.24	$0.08

Table 11-2 shows the PJM day-ahead load-weighted average LMP components for the first three months of 2008 through 2026. The day-ahead load-weighted average LMP increased by $41.70, or 77.8 percent, from $53.60 in the first three months of 2025 to $95.30 in the first three months of 2026. The day-ahead load-weighted average congestion component decreased by $0.20 from $0.11 in the first three months of 2025 to -$0.09 in the first three months of 2026. The day-ahead load-weighted average loss component was -$0.02 in the first three months of 2026, compared to $0.16 in the first three months of 2025. The day-ahead load-weighted average energy component increased by $42.08, or 78.9 percent, from $53.32 in the first three months of 2025 to

9 This is referred to as dispatching units out of economic merit order. Economic merit order is the order of all generator offers from lowest to highest cost. Congestion occurs when loadings on transmission facilities mean the next unit in merit order cannot be used and a higher cost unit must be used in its place.

10 The PJM real-time, load-weighted price is weighted by accounting load, which differs from the state-estimated load used in determination of the energy component (SMP). In the real-time energy market, the distributed load reference bus is weighted by state-estimated load in real time. When the LMP is calculated in real time, the energy component equals the system load-weighted price. But real-time bus-specific loads are adjusted, after the fact, based on updated load information from meters. This meter adjusted load is accounting load that is used in settlements and is used to calculate reported PJM load-weighted prices. This after the fact adjustment means that the real-time energy market energy component of LMP (SMP) and the PJM real-time load-weighted LMP are not equal. The difference between the real-time energy component of LMP and the PJM wide real-time load-weighted average LMP is a result of the difference between state-estimated and metered loads used to weight the load-weighted reference bus and the load-weighted LMP. Without these adjustments, the congestion component of system average LMP would be zero.

11 Calculated values shown in Section 11, "Congestion and Marginal Losses," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

$95.40 in the first three months of 2026. Using a load-weighted reference bus, the day-ahead load-weighted average congestion component of LMP should be zero. PJM's load-weighted reference bus congestion component is zero based on day-ahead firm load weights. Total billing however, includes price sensitive demand and virtual load congestion related charges, which makes the total load weights in accounting different than the load weights used to determine the SMP at the load-weighted reference bus. The resulting load-weighted average price from PJM settlement for congestion and marginal losses components of price in day ahead is therefore not zero, although this component is not fully accurate.

Table 11-2 Day-ahead load-weighted average LMP components (Dollars per MWh): January through March, 2008 through 2026

(Jan - Mar)	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2008	$68.00	$68.14	$0.05	($0.20)
2009	$49.44	$49.75	($0.18)	($0.13)
2010	$47.77	$47.74	$0.01	$0.02
2011	$47.14	$47.36	($0.11)	($0.11)
2012	$31.51	$31.45	$0.08	($0.03)
2013	$37.26	$37.19	$0.07	$0.01
2014	$94.96	$94.52	$0.43	$0.00
2015	$52.02	$51.55	$0.48	($0.02)
2016	$27.94	$27.80	$0.15	($0.00)
2017	$30.40	$30.39	$0.03	($0.02)
2018	$47.55	$47.36	$0.20	($0.01)
2019	$30.76	$30.66	$0.11	($0.01)
2020	$20.12	$20.14	($0.01)	($0.01)
2021	$31.58	$31.34	$0.19	$0.05
2022	$54.23	$53.26	$0.63	$0.34
2023	$32.16	$32.12	($0.01)	$0.05
2024	$32.34	$32.28	$0.01	$0.04
2025	$53.60	$53.32	$0.11	$0.16
2026	$95.30	$95.40	($0.09)	($0.02)

Table 11-3 shows the PJM real-time load-weighted average LMP by constrained and unconstrained hours. A constrained hour is any hour during which one or more facilities are congested.

Table 11-3 Real-time load-weighted average LMP by constrained and unconstrained hours (Dollars per MWh): January 2025 through March 2026

	2025		2026	
	Constrained Hours	Unconstrained Hours	Constrained Hours	Unconstrained Hours
Jan	$63.62	$39.41	$117.02	$25.97
Feb	$48.92	$41.67	$93.41	$0.00
Mar	$42.11	$0.00	$46.21	$16.92
Apr	$46.14	$21.60		
May	$37.27	$25.96		
Jun	$68.44	$22.42		
Jul	$60.05	$39.23		
Aug	$40.75	$23.95		
Sep	$43.82	$21.96		
Oct	$51.01	$0.00		
Nov	$47.17	$27.70		
Dec	$55.48	$29.70		
Avg	$51.25	$28.78	$87.88	$24.59

Table 11-4 shows the monthly comparison of real-time constrained and unconstrained hours from January 2025 and March 2026. A constrained hour is any hour during which one or more facilities are congested. There were less real-time constrained hours in the first three months of 2026 than in the first three months of 2025.

Table 11-4 Real-time constrained and unconstrained hours by month: January 2025 through March 2026

	2025		2026		Difference	
	Constrained Hours	Unconstrained Hours	Constrained Hours	Unconstrained Hours	Constrained Hours	Unconstrained Hours
Jan	711	33	734	10	23	(23)
Feb	670	2	651	21	(19)	19
Mar	743	0	732	0	(11)	0
Apr	696	24				
May	595	149				
Jun	714	6				
Jul	717	27				
Aug	658	86				
Sep	713	7				
Oct	720	0				
Nov	682	38				
Dec	731	13				
Total	8,350	385	2,117	31	(7)	(4)

Zonal Components

The load weighted congestion component of LMPs (CLMPs) provided in the following tables (Table 11-5 and Table 11-6) are not a metric of the amount of congestion paid by load in a zone. The listed CLMPs show whether prices (LMPs) in a zone are higher or lower than the load weighted average price in the PJM system due to transmission constraints.

The components of real-time LMP for each control zone are presented in Table 11-5 for the first three months of 2025 and 2026. In the first three months of 2026, PEPCO had the highest real-time congestion component of LMP, $45.18, and COMED had the lowest real-time congestion component of LMP, -$41.37.

Table 11-5 Zonal real-time load-weighted average LMP components (Dollars per MWh): January through March, 2025 and 2026

	2025 (Jan - Mar)				2026 (Jan - Mar)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
ACEC	$49.62	$52.38	($4.12)	$1.36	$81.92	$87.86	($8.73)	$2.78
AEP	$50.81	$51.70	$0.16	($1.05)	$73.05	$85.71	($10.11)	($2.54)
APS	$55.24	$52.36	$2.28	$0.60	$111.40	$88.61	$21.36	$1.42
ATSI	$48.40	$50.89	($2.11)	($0.38)	$64.48	$83.37	($17.20)	($1.68)
BGE	$64.49	$53.26	$8.77	$2.46	$136.38	$91.54	$39.80	$5.04
COMED	$33.31	$51.11	($14.32)	($3.49)	$36.12	$83.76	($41.37)	($6.28)
DAY	$48.40	$51.90	($3.68)	$0.18	$70.57	$86.31	($15.17)	($0.57)
DOM	$66.35	$52.67	$12.19	$1.48	$131.10	$89.44	$38.44	$3.23
DPL	$54.40	$53.47	($1.67)	$2.60	$97.68	$93.37	($1.29)	$5.60
DUKE	$46.49	$52.12	($4.07)	($1.55)	$70.50	$88.24	($14.11)	($3.62)
DUQ	$47.32	$50.80	($2.54)	($0.94)	$64.03	$84.86	($18.94)	($1.89)
EKPC	$51.83	$54.23	($0.90)	($1.50)	$77.81	$95.83	($13.82)	($4.20)
JCPLC	$50.65	$52.07	($3.06)	$1.63	$82.28	$86.97	($7.88)	$3.19
MEC	$51.19	$52.05	($1.53)	$0.67	$82.63	$85.85	($5.20)	$1.98
OVEC	$42.86	$50.37	($5.28)	($2.23)	$63.53	$83.47	($15.67)	($4.27)
PE	$56.04	$51.37	$3.72	$0.95	$76.00	$85.08	($10.48)	$1.40
PECO	$48.51	$52.03	($4.23)	$0.71	$81.08	$87.90	($8.53)	$1.71
PEPCO	$64.59	$53.33	$9.10	$2.16	$141.62	$92.19	$45.18	$4.25
PPL	$47.70	$52.12	($4.62)	$0.20	$82.13	$87.73	($6.57)	$0.97
PSEG	$51.74	$51.59	($1.48)	$1.63	$82.47	$85.21	($5.85)	$3.11
REC	$55.95	$51.14	$3.20	$1.61	$84.08	$83.67	($2.46)	$2.87
PJM	$52.20	$52.03	$0.13	$0.04	$87.57	$87.24	$0.24	$0.08

The components of day-ahead LMP for each control zone are presented in Table 11-6 for the first three months of 2025 and 2026. In the first three months of 2026, PEPCO had the highest day-ahead congestion component of LMP, $41.52, and COMED had the lowest day-ahead congestion component of LMP, -$27.85.

Table 11-6 Zonal day-ahead load-weighted average LMP components (Dollars per MWh): January through March, 2025 and 2026

	2025 (Jan - Mar)				2026 (Jan - Mar)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
ACEC	$53.56	$53.47	($1.77)	$1.86	$91.59	$96.10	($8.19)	$3.68
AEP	$52.15	$53.21	$0.07	($1.13)	$80.74	$94.74	($10.75)	($3.25)
APS	$55.32	$53.55	$0.99	$0.78	$116.30	$96.27	$18.44	$1.60
ATSI	$51.78	$52.14	($0.23)	($0.13)	$74.66	$91.33	($15.35)	($1.32)
BGE	$64.67	$54.47	$7.47	$2.73	$143.89	$99.89	$37.61	$6.39
COMED	$37.23	$52.23	($11.52)	($3.48)	$55.34	$90.51	($27.85)	($7.32)
DAY	$52.03	$53.16	($1.29)	$0.16	$81.48	$95.11	($12.71)	($0.92)
DOM	$63.16	$54.22	$7.28	$1.65	$132.92	$99.79	$30.08	$3.05
DPL	$58.59	$54.94	$0.43	$3.22	$106.54	$101.61	($1.38)	$6.31
DUKE	$50.38	$53.66	($1.63)	($1.64)	$80.74	$97.10	($12.08)	($4.28)
DUQ	$49.56	$52.45	($1.95)	($0.94)	$71.54	$92.36	($18.66)	($2.16)
EKPC	$53.77	$56.98	($1.07)	($2.14)	$91.36	$110.17	($12.86)	($5.94)
JCPLC	$54.05	$53.07	($1.02)	$2.00	$92.18	$94.86	($6.58)	$3.90
MEC	$55.48	$53.03	$1.41	$1.03	$92.69	$93.23	($3.13)	$2.59
OVEC	$39.20	$41.71	($0.65)	($1.86)	$39.49	$38.65	$2.41	($1.56)
PE	$57.59	$51.58	$4.77	$1.24	$79.63	$84.91	($7.75)	$2.47
PECO	$52.43	$53.23	($1.91)	$1.10	$90.85	$96.86	($8.42)	$2.41
PEPCO	$64.85	$54.50	$7.84	$2.51	$147.66	$101.06	$41.52	$5.07
PPL	$51.24	$53.27	($2.32)	$0.28	$92.45	$95.11	($3.87)	$1.21
PSEG	$53.48	$52.31	($0.81)	$1.99	$88.94	$89.99	($4.63)	$3.58
REC	$55.72	$50.47	$3.52	$1.73	$89.17	$87.69	($1.52)	$3.01
PJM	$53.60	$53.32	$0.11	$0.16	$95.30	$95.40	($0.09)	($0.02)

Hub Components

The components of real-time LMP for each hub are presented in Table 11-7 for the first three months of 2025 and 2026.[12]

12 The real-time components of LMP are the simple average of the hourly components for each hub. Some hubs include only generation buses and do not include load buses. The real-time components of LMP were previously reported as the real-time, load-weighted, average of the hourly components of LMP.

Table 11-7 Hub real-time average LMP components (Dollars per MWh): January through March, 2025 and 2026

	2025 (Jan - Mar)				2026 (Jan - Mar)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$42.64	$49.01	($4.04)	($2.34)	$58.14	$77.50	($15.00)	($4.37)
AEP-DAY Hub	$45.24	$49.01	($2.31)	($1.47)	$62.31	$77.50	($12.18)	($3.01)
ATSI Gen Hub	$46.24	$49.01	($1.46)	($1.31)	$59.94	$77.50	($14.49)	($3.08)
Chicago Gen Hub	$31.06	$49.01	($14.10)	($3.85)	$36.01	$77.50	($34.74)	($6.75)
Chicago Hub	$31.78	$49.01	($14.02)	($3.21)	$34.37	$77.50	($37.56)	($5.57)
Dominion Hub	$58.25	$49.01	$8.81	$0.43	$103.75	$77.50	$24.96	$1.29
Eastern Hub	$48.70	$49.01	($2.43)	$2.12	$77.15	$77.50	($4.38)	$4.02
N Illinois Hub	$31.61	$49.01	($13.92)	($3.48)	$34.20	$77.50	($37.26)	($6.04)
New Jersey Hub	$48.10	$49.01	($2.36)	$1.45	$73.10	$77.50	($7.02)	$2.62
Ohio Hub	$45.33	$49.01	($2.11)	($1.58)	$61.72	$77.50	($12.61)	($3.17)
West Interface Hub	$49.99	$49.01	$1.67	($0.69)	$74.61	$77.50	($1.21)	($1.69)
Western Hub	$52.72	$49.01	$2.86	$0.84	$90.24	$77.50	$11.18	$1.56

The components of day-ahead LMP for each hub are presented in Table 11-8 for the first three months of 2025 and 2026.

Table 11-8 Hub day-ahead average LMP components (Dollars per MWh): January through March, 2025 and 2026

	2025 (Jan - Mar)				2026 (Jan - Mar)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$45.96	$50.03	($1.68)	($2.40)	$67.14	$84.53	($12.25)	($5.14)
AEP-DAY Hub	$47.91	$50.03	($0.67)	($1.45)	$70.66	$84.53	($10.33)	($3.54)
ATSI Gen Hub	$49.21	$50.03	$0.13	($0.96)	$68.60	$84.53	($13.28)	($2.65)
Chicago Gen Hub	$34.73	$50.03	($11.47)	($3.84)	$51.10	$84.53	($25.70)	($7.74)
Chicago Hub	$35.43	$50.03	($11.40)	($3.20)	$51.46	$84.53	($26.45)	($6.62)
Dominion Hub	$55.81	$50.03	$5.30	$0.47	$102.14	$84.53	$17.02	$0.59
Eastern Hub	$52.13	$50.03	($0.51)	$2.60	$84.89	$84.53	($4.33)	$4.68
N Illinois Hub	$35.19	$50.03	($11.35)	($3.49)	$51.08	$84.53	($26.33)	($7.12)
New Jersey Hub	$50.67	$50.03	($1.16)	$1.79	$81.85	$84.53	($5.93)	$3.24
Ohio Hub	$47.95	$50.03	($0.55)	($1.53)	$70.20	$84.53	($10.63)	($3.70)
West Interface Hub	$50.96	$50.03	$1.45	($0.52)	$80.55	$84.53	($2.15)	($1.84)
Western Hub	$53.91	$50.03	$2.76	$1.11	$97.41	$84.53	$10.30	$2.58

Congestion

Congestion Accounting

In PJM accounting, total congestion costs equal net implicit CLMP charges, plus net explicit CLMP charges, plus net inadvertent CLMP charges. Implicit CLMP charges equal implicit withdrawal charges less implicit injection credits. Explicit CLMP charges are the net CLMP charges associated with the injection credits and withdrawal charges for point to point energy transactions. Inadvertent CLMP charges are not directly attributable to specific participants that are distributed on a load ratio basis. Each of these categories of congestion costs is comprised of day-ahead and balancing congestion costs.

While PJM accounting focuses on CLMPs, the individual CLMP values at any bus are irrelevant to the calculation of congestion, as CLMPs are just an artificial deconstruction of LMP based on a selected reference bus. Holding aside the marginal loss component of LMP, differences in the LMPs are caused by binding constraints in the least cost security constrained dispatch market solution, and total congestion is the net surplus revenue that remains after all sources and sinks are credited or charged their LMPs. Changing the components of LMP by electing a different reference bus does not change the LMPs or the difference between LMPs for a given market solution or actual congestion, it merely changes the components of the LMP.

Congestion occurs in the day-ahead and real-time energy markets.[13] Day-ahead congestion costs are based on day-ahead MWh while balancing congestion costs are based on deviations between day-ahead and real-time MWh priced at the congestion price in the real-time energy market.

Implicit CLMP charges are the CLMP charges calculated for energy injected or withdrawn at a location. The explicit CLMP charges are the CLMP charges calculated for transactions with a defined

13 When the term *congestion charge* is used in documents by PJM's Market Settlement Operations, it has the same meaning as the term *congestion costs* as used here.

source and a sink. For example, implicit CLMP charges are calculated for network load and explicit CLMP charges are calculated for up to congestion transactions (UTCs). Inadvertent CLMP charges are CLMP charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour.

CLMP charges and CLMP credits are calculated for both the day-ahead and balancing energy markets.

- **Day-Ahead Implicit Load CLMP Charges.** Day-ahead implicit withdrawal charges are calculated for all cleared demand, decrement bids and day-ahead energy market sale transactions. Day-ahead implicit withdrawal charges are calculated using MW and the load bus CLMP, the decrement bid bus CLMP or the CLMP at the source of the sale transaction.
- **Day-Ahead Implicit Generation CLMP Credits.** Day-ahead implicit injection credits are calculated for all cleared generation, increment offers and day-ahead energy market purchase transactions.[14] Day-ahead implicit injection credits are calculated using MW and the generator bus CLMP, the increment offer's bus CLMP or the CLMP at the sink of the purchase transaction.
- **Balancing Implicit Load CLMP Charges.** Balancing implicit withdrawal charges are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing implicit withdrawal charges are calculated using MW deviations and the real-time CLMP for each aggregate where a deviation exists.
- **Balancing Implicit Generation CLMP Credits.** Balancing implicit injection credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing implicit injection credits are calculated using MW deviations and the real-time CLMP for each aggregate where a deviation exists.
- **Explicit CLMP Charges.** Explicit CLMP charges are the net CLMP costs associated with point to point energy transactions. Day-ahead explicit CLMP charges equal the product of the transacted MW and CLMP differences between sources (origins) and sinks (destinations) in the day-ahead energy market. Balancing explicit CLMP charges equal the product of the deviations between the real-time and day-ahead transacted MW and the differences between the real-time CLMP at the transactions' sources and sinks. Explicit CLMP charges are calculated for internal purchase, import and export transaction, and up to congestion transactions (UTCs.)
- **Inadvertent CLMP Charges.** Inadvertent CLMP charges are charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour. This inadvertent interchange of energy may be positive or negative, where positive interchange typically results in a charge while negative interchange typically results in a credit. Inadvertent CLMP charges are common costs, not directly attributable to specific participants that are distributed on a load ratio basis.[15]

The congestion accounting calculation equations are in Table 11-9.

14 Internal bilateral transactions are included in the tariff definitions of Market Participant Energy Injections and Market Participant Energy Withdrawals. The purchase part of an internal bilateral transaction is an injection to the buyer and the sale part of an internal bilateral transaction is a withdrawal to the seller. The tariff (Attachment K) also says market participants will be charged implicit CLMP charges for all Market Participant Energy Withdrawals and will be credited implicit CLMP credits for all Market Participant Energy Injections. The seller of an internal bilateral transaction will be charged implicit CLMP charges at the source and the buyer of an internal bilateral transaction will be credited implicit CLMP credits at the sink. Internal bilateral transaction CLMP credits and charges sum to zero, as the IBT is merely a transfer of ownership injection and withdrawal MW and associated charges and credits between participants, meaning that the sum of all MW and all credits and all charges with and without IBTs are the same.

15 PJM Operating Agreement Schedule 1 §3.7.

Table 11-9 Congestion accounting calculations

Congestion Category	Calculation
Day-Ahead Implicit Withdrawal CLMP Charges	Day-Ahead Demand MWh * Day-Ahead CLMP
Day-Ahead Implicit Injection CLMP Credits	Day-Ahead Supply MWh * Day-Ahead CLMP
Day-Ahead Explicit CLMP Charges	Day-Ahead Transaction MW * (Day-Ahead Sink CLMP - Day-Ahead Source CLMP)
Day-Ahead Total Congestion Costs	Day-Ahead Implicit Withdrawal CLMP Charges - Day-Ahead Implicit Injection CLMP Credits + Day-Ahead Explicit CLMP Charges
Balancing Implicit Withdrawal CLMP Charges	Balancing Demand MWh * Real-Time CLMP
Balancing Implicit Injection CLMP Credits	Balancing Supply MWh * Real-Time CLMP
Balancing Explicit CLMP Costs	Balancing Transaction MW * (Real-Time Sink CLMP - Real-Time Source CLMP)
Balancing Total Congestion Costs	Balancing Implicit Withdrawal CLMP Charges - Balancing Implicit Injection CLMP Credits + Balancing Explicit CLMP Costs
Total Congestion Costs	Day-Ahead Total Congestion Costs + Balancing Total Congestion Costs

MWh Category	Definition
Day-Ahead Demand MWh	Cleared Demand, Decrement Bids, Energy Sale Transactions
Day-Ahead Supply MWh	Cleared Generation, Increment Bids, Energy Purchase Transactions
Real-Time Demand MWh	Load and Energy Sale Transactions
Real-Time Supply MWh	Generation and Energy Purchase Transactions
Balancing Demand MWh	Real-Time Demand MWh - Day-Ahead Demand MWh
Balancing Supply MWh	Real-Time Supply MWh - Day-Ahead Supply MWh

PJM billing items include Day-Ahead Transmission Congestion Charges, Day-Ahead Transmission Congestion Credits, Balancing Transmission Congestion Charges, and Balancing Transmission Congestion Credits. Those line items are calculated for each PJM member. The congestion bill shows the CLMP charges or credits collected from the PJM market participants. However, the sum of an individual customer's CLMP credits or charges on the customer's bill is not a measure of the congestion paid by that customer.

The congestion paid by a customer is the difference between what the customer paid for energy and what all network sources of that energy were paid to serve that customer. A load customer's congestion bill, in contrast, merely indicates whether the LMP they paid for their withdrawals is higher or lower than the system energy price due to transmission constraints. The customer's bill does not measure congestion paid by the customer, only how much the customer was charged and credited for their MW positions. The congestion costs associated with specific constraints are the sum of the total day-ahead and balancing congestion costs associated with those constraints. Zonal congestion is calculated on a constraint by constraint basis. The congestion calculations are the total difference between what the zonal load pays in CLMP charges and what the generation that serves that load is paid, regardless of whether the zone is a net importer or a net exporter of generation. CLMPs can be both positive and negative and CLMP charges and CLMP credits can be both positive and negative. CLMP charges, positive or negative, are paid by withdrawals and CLMP credits, positive or negative, are paid to injections. Total congestion costs (the sum of charges and credits), when positive, measure the net congestion payment by a participant group and when negative, measure the net congestion credit paid to a participant group. Explicit CLMP charges, when positive, measure the CLMP payment from a PJM member and when negative, measure the CLMP credit paid to a PJM member. Explicit CLMP charges are calculated for up to congestion transactions (UTCs). In all cases, whether positive or negative, CLMP charges and credits merely indicate whether the LMP being paid by withdrawals or credited to injections is higher or lower than the system weighted average price due to binding transmission constraints.

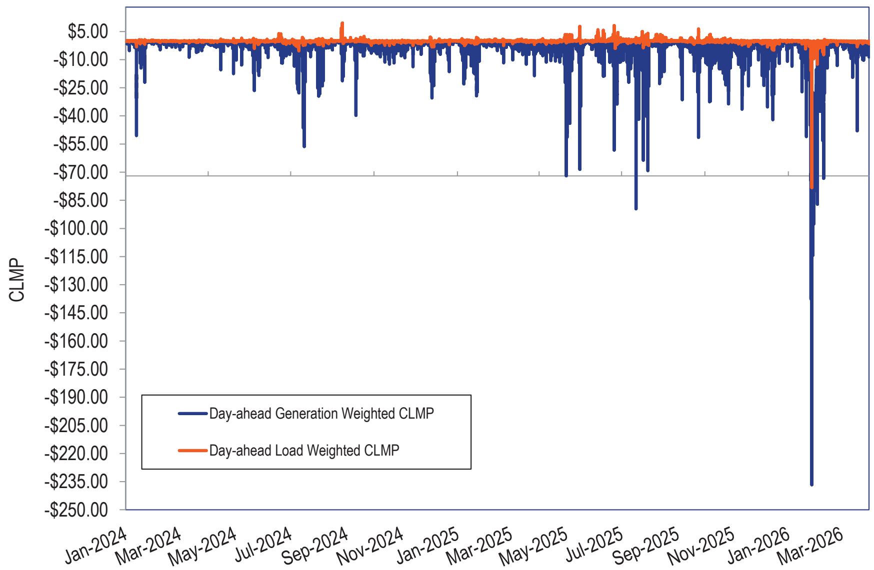
The congestion accounting definitions are misleading. Load pays congestion. Congestion is the difference between what load pays for energy and what generation is paid for energy due to binding transmission constraints. Generation does not pay congestion. Some generation receives a price lower than SMP and some generation receives a price greater than SMP but that does not mean that generation is paying congestion. It means only that generation is being paid an LMP that is higher or lower than the system load-weighted average LMP.

The CLMP is calculated with respect to the LMP at the system reference bus, also called the system marginal price (SMP). When a transmission constraint occurs, the resulting CLMP is positive on one side of the constraint and negative on the other side of the constraint and the corresponding CLMP costs are positive or negative. For each transmission constraint, the CLMP reflects the cost of a constraint at a pricing node and is equal to the product of the constraint shadow price and the distribution factor from the constraint to the pricing node. The total CLMP at a pricing node is the sum of all constraint contributions to LMP and is equal to the difference between the actual LMP that results from transmission constraints, excluding losses, and the SMP. If an area experiences lower prices because of a constraint, the CLMP in that area is negative.[16]

Load-weighted LMP components are calculated relative to a load-weighted, average LMP. At the load-weighted reference bus, which represents the load center of the system, the LMP calculation is designed to include no congestion or loss components, but it may include congestion. The load-weighted average CLMP across all load buses, calculated relative to that reference bus, is equal to, or very close to, zero, with non-zero results caused by state estimator error and after the fact meter updates. The sum of load related CLMP charges is logically zero and the small reported differences are the result of accounting issues. A positive CLMP at a load bus indicates that the load at that bus has a total energy price higher than the average LMP, due to transmission constraints. A negative CLMP at a load bus indicates that the load at that bus has a total energy price lower than the average LMP, due to transmission constraints. The LMPs at the load buses are a function of marginal generation bus LMPs determined through the least cost security constrained economic dispatch which accounts for transmission constraints and marginal losses. Due to transmission constraints, the average generation weighted CLMP for generation resources is lower than the LMP at the load-weighted reference bus price. Calculated relative to the load reference bus which has a CLMP of zero, this means that the average of the generation bus CLMPs is negative. This means that total generation CLMP credits are negative. Figure 11-1 shows the weighted average CLMPs of generation and load in the day-ahead market. Figure 11-1 shows that from January 2024 to March 2026, day-ahead generation weighted CLMPs were generally negative and day-ahead, load weighted CLMPs were generally positive, indicating that load was charged a higher weighted average LMP for energy as a result of transmission constraints than the weighted average LMP generation was paid to provide that energy. This means that total CLMP load payments are higher than total CLMP generation credits. The difference in load payments and generation credits (load charges minus generation credits) is congestion (Table 11-12 and Table 11-13). This result is a product of the least cost, security constrained dispatch and the use of a load-weighted reference bus that is used for the determination of the components of LMP. More generally, in a least cost, security constrained market solution the weighted average LMP at load buses is higher than the weighted average price at generation buses.

16 For an example of the congestion accounting methods used in this section, see *MMU Technical Reference for PJM Markets*, at "FTRs and ARRs," <http://www.monitoringanalytics.com/reports/Technical_References/docs/2010-som-pjm-technical-reference.pdf>.

Figure 11-1 Day-ahead generation weighted CLMPs and day-ahead load-weighted CLMPs: January 2024 through March 2026



Total Congestion

Total congestion costs in PJM in the first three months of 2026 were $2,015.2 million, comprised of implicit withdrawal charges of $615.7 million, minus implicit injection credits of -$1,464.9 million, plus explicit charges of -$65.3 million. Total congestion is the difference between what load pays for energy and what generation is paid for energy, due to binding transmission constraints.

Table 11-10 shows total congestion for the first three months of 2008 and 2026. Total congestion costs in Table 11-10 include congestion associated with PJM facilities and those associated with reciprocal, coordinated flowgates in MISO and in NYISO.[17 18]

Table 11-10 Total congestion costs (Dollars (Millions)): January through March, 2008 through 2026[19]

(Jan - Mar)	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$486	NA	$7,718	6.3%
2009	$307	(36.8%)	$7,515	4.1%
2010	$345	12.4%	$8,415	4.1%
2011	$360	4.3%	$9,584	3.8%
2012	$122	(66.0%)	$6,938	1.8%
2013	$186	51.9%	$7,762	2.4%
2014	$1,236	564.8%	$21,070	5.9%
2015	$632	(48.9%)	$14,040	4.5%
2016	$292	(53.7%)	$9,500	3.1%
2017	$158	(45.9%)	$9,710	1.6%
2018	$661	318.4%	$14,520	4.6%
2019	$164	(75.2%)	$11,600	1.4%
2020	$85	(48.1%)	$8,750	1.0%
2021	$121	42.2%	$11,260	1.1%
2022	$510	321.5%	$18,080	2.8%
2023	$175	(65.6%)	$11,890	1.5%
2024	$321	82.9%	$12,350	2.6%
2025	$503	56.8%	$18,690	2.7%
2026	$2,015	300.4%	$36,350	5.5%

CLMP charges and credits are not congestion. CLMP charges and credits reflect marginal energy price differences caused by binding system constraints. Congestion is the sum of all congestion related charges and credits. In a two settlement system all virtual bids have net zero MW after their day-ahead and balancing positions are cleared, which means that virtual bids are fully settled in terms of CLMP credits and charges at the close of the market for any particular day, with either a net loss or profit due to differences between day-ahead and real-time prices. Net payouts (negative credits) to virtual bids

17 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) Section 6.1, Effective Date: May 30, 2016. <http://www.pjm.com/documents/agreements.aspx>.
18 See "NYISO Tariffs New York Independent System Operator, Inc.," (June 21, 2017) 35.12.1, Effective Date: May 1, 2017. <http://www.pjm.com/documents/agreements.aspx>.
19 In Table 11-10, the MMU uses Total PJM Billing values provided by PJM. For 2019 and after, the MMU has modified the Total PJM Billing calculation to better reflect historical PJM total billing through the PJM settlement process.

appear as negative adjustments to either day-ahead or balancing congestion and net charges to virtual bids appear as positive adjustments to either day-ahead or balancing congestion.

Table 11-11 shows total congestion by day-ahead and balancing component for the first three months of 2008 through 2026.

Table 11-11 Total CLMP credits and charges by accounting category (Dollars (Millions)): January through March, 2008 through 2026

	Day-Ahead				Balancing					
(Jan - Mar)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Congestion Costs
2008	$332.4	($220.0)	$39.9	$592.3	($46.0)	$29.5	($31.2)	($106.7)	$0.0	$485.6
2009	$120.2	($221.3)	$47.9	$389.5	($14.2)	($6.0)	($74.4)	($82.6)	($0.0)	$306.9
2010	$85.9	($293.1)	$12.9	$391.9	($5.7)	$12.1	($29.1)	($47.0)	($0.0)	$344.9
2011	$176.5	($226.7)	$4.1	$407.3	$21.6	$27.8	($41.2)	($47.4)	$0.0	$359.9
2012	$21.9	($131.4)	$27.5	$180.9	($5.1)	$11.3	($42.0)	($58.4)	$0.0	$122.4
2013	$85.0	($199.1)	$47.8	$331.9	($6.6)	$73.3	($66.0)	($145.9)	$0.0	$185.9
2014	$333.7	($1,193.9)	($94.3)	$1,433.3	$73.0	$208.9	($61.3)	($197.2)	$0.0	$1,236.1
2015	$327.0	($457.9)	($11.0)	$773.9	$5.4	$69.6	($78.0)	($142.2)	($0.0)	$631.7
2016	$120.2	($193.5)	$9.2	$322.9	($1.1)	$11.9	($17.7)	($30.8)	$0.0	$292.2
2017	$24.2	($137.7)	$3.0	$164.9	($0.3)	$7.5	$0.9	($6.9)	($0.0)	$158.0
2018	$130.9	($557.5)	($46.7)	$641.7	$12.8	$23.6	$30.1	$19.3	$0.0	$661.0
2019	$53.3	($137.7)	$11.2	$202.2	($1.8)	$20.1	($16.4)	($38.3)	$0.0	$163.9
2020	$13.5	($75.7)	$14.1	$103.3	($0.2)	$3.8	($14.2)	($18.2)	($0.0)	$85.1
2021	$82.3	($123.5)	$18.7	$224.5	($26.7)	$39.9	($36.8)	($103.4)	$0.0	$121.1
2022	$304.6	($364.6)	$32.2	$701.4	($46.4)	$79.6	($65.1)	($191.2)	$0.0	$510.3
2023	$53.7	($151.9)	$20.6	$226.2	$2.9	$7.0	($46.7)	($50.8)	$0.0	$175.5
2024	$110.2	($247.8)	$40.7	$398.7	($5.8)	$20.1	($51.8)	($77.7)	$0.0	$321.0
2025	$165.3	($496.6)	$41.7	$703.5	($26.7)	$79.1	($94.5)	($200.2)	($0.0)	$503.3
2026	$647.8	($1,610.9)	$22.0	$2,280.7	($32.1)	$146.0	($87.3)	($265.5)	$0.0	$2,015.2

Charges and Credits versus Congestion: Virtual Transactions, Load and Generation

In PJM's two settlement system, there is a day-ahead market and a real-time, balancing market that make up a market day.

In a two settlement system all virtual bids have net zero MW after their day-ahead and balancing positions are cleared, which means that virtual bids are fully settled in terms of CLMP credits and charges at the close of each market day, with either a net loss or profit due to differences between day-ahead and real-time prices. Net payouts (negative credits) to virtual bids appear as negative adjustments to either day-ahead or balancing congestion and net charges to virtual bids appear as positive adjustments to either day-ahead or balancing congestion.

Unlike virtual bids, physical load and generation have net MW at the close of a market day's day-ahead and balancing settlement.

Generation does not pay congestion. Some generation receives a price lower than SMP and some generation receives a price greater than SMP but that does not mean that generation is paying congestion. It means that generation is being paid an LMP that is higher or lower than the system load-weighted average LMP.

The residual difference between total load charges (day-ahead and balancing) and generation credits (day-ahead and balancing) after virtual bids have settled their day-ahead and balancing positions is congestion. That is, congestion is the difference between what withdrawals (load) pay for energy and what injections (generation) are paid for energy due to binding transmission constraints, after virtual bids are settled at the end of the market day. Load is the source of the net surplus after generation is paid and virtuals are settled at the end of the market day. Load pays congestion.

Table 11-12 and Table 11-13 show the total CLMP charges and credits for each transaction type in the first three months of 2026 and 2025. Table 11-12 shows that in the first three months of 2026 DECs were paid $22.2 million in CLMP charges in the day-ahead market, were paid $29.2 million in CLMP credits in the balancing energy market, resulting in a net payment of $51.4 million. In the first three months of 2026, INCs paid $99.9 million in CLMP charges in the day-ahead market, were paid $160.5 million in CLMP credits in the balancing energy market resulting in a net payment of $61.5 million. In the first three months of 2026, up to congestion (UTCs) paid $24.4 million in CLMP charges in the day-ahead market, were paid $83.2 million in CLMP credits in the balancing market resulting in a total payment of $58.8 million in total CLMP credits.

Table 11-12 Total CLMP credits and charges by transaction type (Dollars (Millions)): January through March, 2026

	CLMP Credits and Charges (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	($22.2)	$0.0	$0.0	($22.2)	($29.2)	$0.0	$0.0	($29.2)	$0.0	($51.4)
Demand	($2.6)	$0.0	$0.0	($2.6)	$71.3	$0.0	$0.0	$71.3	$0.0	$68.7
Demand Response	$4.4	$0.0	$0.0	$4.4	($4.5)	$0.0	$0.0	($4.5)	$0.0	($0.1)
Explicit Congestion Only	$0.0	$0.0	$0.1	$0.1	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.1
Explicit Congestion and Loss Only	$0.0	$0.0	($0.8)	($0.8)	$0.0	$0.0	$0.0	$0.0	$0.0	($0.8)
Export	($49.4)	$0.0	($0.7)	($50.1)	($61.0)	$0.0	($3.0)	($64.0)	$0.0	($114.1)
Generation	$0.0	($2,213.1)	$0.0	$2,213.1	$0.0	$53.0	$0.0	($53.0)	$0.0	$2,160.0
Import	$0.0	($15.5)	$0.0	$15.5	$0.0	($59.1)	$0.0	$59.1	$0.0	$74.6
INC	$0.0	($99.0)	$0.0	$99.0	$0.0	$160.5	$0.0	($160.5)	$0.0	($61.5)
Internal Bilateral	$717.7	$716.8	($0.9)	($0.0)	($6.9)	($6.7)	$0.0	($0.2)	$0.0	($0.2)
Up to Congestion	$0.0	$0.0	$24.4	$24.4	$0.0	$0.0	($83.2)	($83.2)	$0.0	($58.8)
Wheel In	$0.0	($0.1)	($0.1)	($0.0)	$0.0	($1.8)	($1.1)	$0.8	$0.0	$0.8
Wheel Out	($0.1)	$0.0	$0.0	($0.1)	($1.8)	$0.0	$0.0	($1.8)	$0.0	($1.9)
Total	$647.8	($1,610.9)	$22.0	$2,280.7	($32.1)	$146.0	($87.3)	($265.5)	$0.0	$2,015.2

Table 11-13 Total CLMP credits and charges by transaction type (Dollars (Millions)): January through March, 2025

	CLMP Credits and Charges (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	($4.3)	$0.0	$0.0	($4.3)	($24.7)	$0.0	$0.0	($24.7)	$0.0	($28.9)
Demand	$28.4	$0.0	$0.0	$28.4	$22.5	$0.0	$0.0	$22.5	$0.0	$50.9
Demand Response	$0.4	$0.0	$0.0	$0.4	($0.7)	$0.0	$0.0	($0.7)	$0.0	($0.3)
Explicit Congestion Only	$0.0	$0.0	$0.1	$0.1	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.1
Explicit Congestion and Loss Only	$0.0	$0.0	($0.6)	($0.6)	$0.0	$0.0	($0.1)	($0.1)	$0.0	($0.7)
Export	($3.5)	$0.0	($0.2)	($3.7)	($20.5)	$0.0	($1.1)	($21.6)	$0.0	($25.3)
Generation	$0.0	($581.5)	$0.0	$581.5	$0.0	($3.1)	$0.0	$3.1	$0.0	$584.6
Import	$0.0	($2.2)	$0.0	$2.2	$0.0	$2.6	$0.0	($2.6)	$0.0	($0.4)
INC	$0.0	($57.4)	$0.0	$57.4	$0.0	$82.8	$0.0	($82.8)	$0.0	($25.4)
Internal Bilateral	$144.4	$144.6	$0.2	$0.0	($2.0)	($1.8)	$0.0	($0.2)	$0.0	($0.2)
Up to Congestion	$0.0	$0.0	$42.2	$42.2	$0.0	$0.0	($92.5)	($92.5)	$0.0	($50.3)
Wheel In	$0.0	($0.1)	($0.1)	$0.0	$0.0	($1.3)	($0.8)	$0.5	$0.0	$0.5
Wheel Out	($0.1)	$0.0	$0.0	($0.1)	($1.3)	$0.0	$0.0	($1.3)	$0.0	($1.5)
Total	$165.3	($496.6)	$41.7	$703.5	($26.7)	$79.1	($94.5)	($200.2)	$0.0	$503.3

Table 11-14 shows the change in total CLMP credits and charges by transaction type in the first three months of 2025 and 2026. Total negative CLMP credits to generation increased by $1,575.4 million, and total CLMP charges to demand increased by $17.8 million. The total CLMP credits to up to congestion transactions (UTCs) decreased by $8.5 million in the first three months of 2026. Total day-ahead CLMP charges to UTCs decreased by $17.8 million in the first three months of 2026. Balancing CLMP credits to UTCs increased by $9.3 million in the first three months of 2026.

Table 11-14 Change in total CLMP credits and charges by transaction type (Dollars (Millions)): January through March, 2025 to 2026

	Change in CLMP Credits and Charges (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	($17.9)	$0.0	$0.0	($17.9)	($4.5)	$0.0	$0.0	($4.5)	$0.0	($22.5)
Demand	($31.0)	$0.0	$0.0	($31.0)	$48.8	$0.0	$0.0	$48.8	$0.0	$17.8
Demand Response	$4.0	$0.0	$0.0	$4.0	($3.9)	$0.0	$0.0	($3.9)	$0.0	$0.2
Explicit Congestion Only	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.1)
Explicit Congestion and Loss Only	$0.0	$0.0	($0.3)	($0.3)	$0.0	$0.0	$0.1	$0.1	$0.0	($0.1)
Export	($45.9)	$0.0	($0.6)	($46.4)	($40.5)	$0.0	($2.0)	($42.4)	$0.0	($88.9)
Generation	$0.0	($1,631.6)	$0.0	$1,631.6	$0.0	$56.1	$0.0	($56.1)	$0.0	$1,575.4
Import	$0.0	($13.4)	$0.0	$13.4	$0.0	($61.6)	($0.0)	$61.6	$0.0	$75.0
INC	$0.0	($41.6)	$0.0	$41.6	$0.0	$77.8	$0.0	($77.8)	$0.0	($36.1)
Internal Bilateral	$573.3	$572.2	($1.1)	($0.0)	($4.9)	($4.8)	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	($17.8)	($17.8)	$0.0	$0.0	$9.3	$9.3	$0.0	($8.5)
Wheel In	$0.0	$0.1	$0.1	($0.0)	$0.0	($0.5)	($0.3)	$0.3	$0.0	$0.3
Wheel Out	$0.1	$0.0	$0.0	$0.1	($0.5)	$0.0	$0.0	($0.5)	$0.0	($0.4)
Total	$482.6	($1,114.3)	($19.7)	$1,577.2	($5.5)	$66.9	$7.2	($65.3)	$0.0	$1,511.9

Table 11-15 compares CLMP credits and charges for each transaction type between the dispatch run and pricing run in first three months of 2026. Total CLMP charges to generation decreased by $677.8 million, and total CLMP charges to demand increased by $1.8 million from the dispatch run to the pricing run. The total CLMP credits to DECs increased by $9.3 million, the total CLMP credits to INCs decreased by $15.3 million and the total CLMP credits to UTCs increased by $27.6 million from the dispatch run to the pricing run.

Table 11-15 Total CLMP credits and charges by dispatch run and pricing run (Dollars (Millions)): January through March, 2026

	CLMP Credits and Charges (Millions)								
	Dispatch Run			Pricing Run			Difference		
Transaction Type	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total
DEC	($33.2)	($27.5)	($60.7)	($22.2)	($29.2)	($51.4)	$11.0	($1.7)	$9.3
Demand	($2.9)	$69.7	$66.8	($2.6)	$71.3	$68.7	$0.2	$1.6	$1.8
Demand Response	$5.6	($4.4)	$1.2	$4.4	($4.5)	($0.1)	($1.2)	($0.1)	($1.3)
Explicit Congestion Only	$0.1	($0.0)	$0.1	$0.1	($0.0)	$0.1	($0.0)	$0.0	($0.0)
Explicit Congestion and Loss Only	($1.3)	$0.0	($1.2)	($0.8)	$0.0	($0.8)	$0.4	($0.0)	$0.4
Export	($70.9)	($61.6)	($132.5)	($50.1)	($64.0)	($114.1)	$20.7	($2.4)	$18.4
Generation	$2,887.3	($49.5)	$2,837.8	$2,213.1	($53.0)	$2,160.0	($674.2)	($3.5)	($677.8)
Import	$17.1	$56.9	$74.0	$15.5	$59.1	$74.6	($1.6)	$2.2	$0.6
INC	$108.6	($154.9)	($46.2)	$99.0	($160.5)	($61.5)	($9.6)	($5.7)	($15.3)
Internal Bilateral	$0.0	($0.2)	($0.2)	($0.0)	($0.2)	($0.2)	($0.0)	($0.0)	($0.0)
Up to Congestion	($7.4)	($79.0)	($86.5)	$24.4	($83.2)	($58.8)	$31.8	($4.2)	$27.6
Wheel In	($0.0)	$0.8	$0.8	($0.0)	$0.8	$0.8	$0.0	($0.0)	($0.0)
Wheel Out	($0.1)	($1.7)	($1.8)	($0.1)	($1.8)	($1.9)	($0.0)	($0.1)	($0.1)
Total	$2,903.0	($251.5)	$2,651.5	$2,280.7	($265.5)	$2,015.2	($622.3)	($14.0)	($636.3)

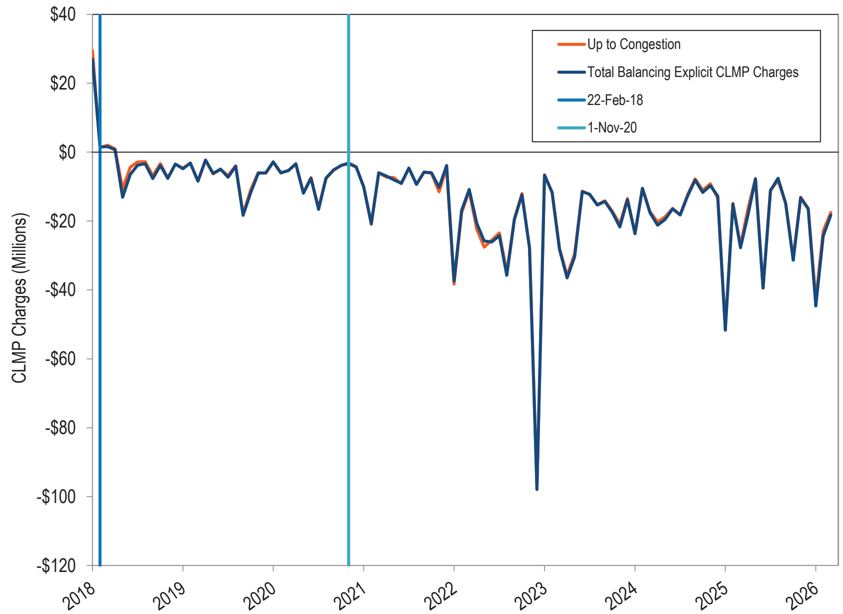
UTCs and Negative Balancing Explicit CLMP Charges

Figure 11-2 shows the change in up to congestion balancing explicit CLMP charges from January 2018 through March 2026. Figure 11-2 shows that UTCs account for almost all balancing explicit CLMP charges in PJM. As shown in Figure 11-2, UTCs are generally paid balancing CLMP credits, which take the form of negative balancing CLMP charges being allocated to UTC positions. In the first three months of 2026, 95.3 percent (-$83.2 million out of -$87.3 million) of negative balancing explicit CLMP charges was incurred by UTCs and 4.7 percent (-$4.1 out of -$87.3 million) was incurred by Explicit Congestion Only, Export, Import and Wheel In transactions (Table 11-12). The vertical line at February 22, 2018, marks the date on which the FERC order that limited UTC trading to hubs, residual metered load, and interfaces was effective.[20] The vertical line at November 1, 2020, marks the date on which the FERC order that required PJM to allocate uplift to up to congestion transactions was effective.[21]

Negative balancing explicit CLMP charges were substantially higher in December 2022 than in other months as a result of transmission constraint penalty factors in the real-time market in 2022. The total negative balancing explicit CLMP charges on December 7 and 8, 2022, and the Winter Storm Elliott days of December 23 through 26, 2022, were 64.1 percent (-$62.3 million out of -$97.2 million) of total negative balancing explicit CLMP charges in December 2022.

20 For additional information about the FERC order, see the *2019 Annual State of the Market Report for PJM*, Appendix F: Congestion and Marginal Losses.
21 172 FERC ¶ 61,046 (2020).

Figure 11-2 Monthly balancing explicit CLMP charges incurred by UTCs: January 2018 through March 2026



Balancing congestion is caused by settling real-time deviations from day-ahead positions at real-time prices. Whether balancing congestion is positive or negative depends on the differences between market solutions (changes in load and/or generation) and differences between the day-ahead and real-time market models including modeled constraints, the transfer capability (line limits) of the modeled constraints and the differences in deviations between day-ahead and real-time flows that result. The deviations are priced at the real-time LMPs.

For example, one source of negative balancing congestion is that the PJM system has less transmission transfer capability in the real-time market than is modeled in the day-ahead market. In order to reduce processing time in the presence of large number of virtual bids and offers, PJM only enforces or models a subset of its physical transmission limits in the day-ahead market. Transmission constraints not modeled in the day-ahead market have unlimited transfer capability in the day-ahead market model. The inclusion of the actual, lower transmission capability in the real-time market requires the use of more high cost generation and the use of less low cost generation to serve load, which means a decrease in congestion.[22] The reduction in real-time congestion compared to day-ahead congestion creates negative balancing congestion.

As a day-ahead spread bid, UTCs can take advantage of and profit from LMP differences caused by modeling differences between the day-ahead and real-time market. UTCs clear between source and sink points with little or no price difference in the day-ahead market, and settle the resulting deviations at higher real-time price differences in the real-time market. The result is negative balancing congestion caused by and paid to UTCs in the form of CLMP credits. This is an example of false arbitrage because the UTCs cannot cause prices to converge and the profits to decrease. As a result of the FERC order requiring load to pay balancing congestion, load is responsible for paying the balancing congestion caused by UTCs.[23]

Table 11-16 provides an example of how UTCs can profit from differences in day-ahead and real-time models and generate negative balancing congestion. In the example, Bus A and Bus B are linked by a transmission line. In the day-ahead market the transmission limit is modeled as 9,999 MW (no limit is enforced in the day-ahead market solution). In the real-time market the physical limit between bus A and bus B is 50 MW. Generation at A has a price of $1.00 and Generation at B has a price of $6. There is 100 MW of load at bus A and 100 MW of load at bus B. There is a UTC of 200 MW that will source at bus A and sink at bus B if the spread in the prices between A and B is less than $1.

As a result of the fact that the transmission capability between A and B is unlimited in the day-ahead market, all of load at A and B can be met with the $1 generation at bus A. The constraint between A and B does not bind in

22 Although it seems counter intuitive, as the amount of low cost generation decreases and the amount of high cost generation increases, the difference between load payments to generation and the payments received by generators goes down. High cost generation receives what load pays.

23 On September 15, 2016, FERC ordered PJM to allocate balancing congestion to load, rather than to FTRs, to modify PJM's Stage 1A ARR allocation process and to continue to use portfolio netting. 153 FERC ¶ 61,180 (2016).

day-ahead so the price at A and B is $1. The price spread between bus A and bus B is zero, which is less than the UTC spread requirement of $1, so the UTC clears. The UTC causes a 200 MW injection at A and 200 MW withdrawal at B, creating 200 MW of flow between bus A and bus B. The 300 MW of combined flow from generation at A and UTC injections at A to the load and UTC sink at B does not exceed the DA modeled limit between A and B. This means that all 200 MW of the UTC injection at A and 200 MW of withdrawal at B can clear without forcing a price spread between A and B. Total day-ahead congestion, which is the difference between CLMP charges and credits, is zero. There is no price difference between the two nodes and every MW of injection and every MW of withdrawal at bus A and bus B settles at the same price.

In the real-time market, the transmission line between bus A and bus B has a 50 MW limit. The UTC does not physically exist in the real-time market and therefore has deviations at Bus A (-200 MW) and at Bus B (+200 MW). The UTC must buy at bus A at the real-time price and sell at bus B at the real-time price to settle its deviations. The load at A (100 MW) and B (100 MW) does not change, so there are no load deviations. With only 50 MW of transmission capability between A and B, the generation at A cannot be used to meet total load on the system. Generation from A meets the load at A (100 MW) and can supply only 50 MW of the 100 MW of load at B. Due to the binding constraint between A and B, the remaining 50 MW of load at B must be met with local generation at B at a cost of $6 and the price at A remains $1.

The UTC must buy 200 MW at A at the real-time price of $1 and sell 200 MW at B at the real-time price of $6. The UTC pays $200 at A and is paid $1,200 at B. The result is a net payment to the UTC of $1,000 in balancing credits.

Table 11-16 shows the balancing credits and charges associated with the real-time deviations in the example. Total congestion (day-ahead plus balancing congestion) in this example is negative $1,250. Total CLMP credits (payments) to generation and the UTC exceed the total charges collected from load. The negative balancing congestion that results is paid by the load under the FERC order.[24]

24 See 153 FERC ¶ 61,180 (2016).

The UTC did not and could not contribute to price convergence between the day-ahead and real-time market and did not and could not improve efficiency in system dispatch or commitment. The UTC took advantage of the modeling differences between the day-ahead and real-time markets. The UTC did significantly increase payments by load. Load was required to pay the UTC $1,000 in negative balancing, over and above the costs of generation that was needed to meet real-time load. The differences in modeling would have resulted in only $250 in negative balancing congestion if there had been no UTCs.

Table 11-16 Example of UTC causing and profiting from negative balancing congestion

Prices	Bus A	Transfer Capability (Line Limit MW)	Bus B	
LMP DA	$1.00	9,999	$1.00	
LMP RT	$1.00	50	$6.00	
Day-Ahead MW	Bus A		Bus B	Total MW
Day-Ahead Generation	200		0	200
Day-Ahead Load	(100)		(100)	(200)
Day-Ahead UTC (+/-)	200		(200)	0
Total MW	300		(300)	0
Day-Ahead Credits and Charges	**Bus A**		**Bus B**	**Total Day-Ahead Congestion**
Total DA Gen Credits	$200.00		$0.00	
Total DA Load Charges	$100.00		$100.00	
Total DA UTC Credits	$200.00		($200.00)	
Total DA Credits	$300.00		($300.00)	$0.00
Total Day-Ahead Congestion (Charges - Credits)				$0.00
Balancing Deviation MW	**Bus A**		**Bus B**	**Total Deviations**
RT GEN Deviations	(50)		50	
RT Load Deviations	0		0	
DA UTC (+/-)	(200)		200	
Total Deviations	(250)		250	0
Balancing Credits and Charges	**Bus A**		**Bus B**	**Balancing Congestion Credits**
Total BA Gen Credits	($50.00)		$300.00	$250.00
Total BA Load Charges	$0.00		$0.00	
Total BA UTC Credits	($200.00)		$1,200.00	$1,000.00
Total BA Credits	($250.00)		$1,500.00	$1,250.00
Total Balancing Congestion (Charges - Credits)				($1,250.00)

Zonal and Load Aggregate Congestion

Zonal, and load aggregate, congestion is calculated on a constraint specific basis for a specific location or set of load pricing nodes (a zone or an aggregate). Local congestion is the difference between what load pays for energy and what generation is paid for energy due to individual binding transmission constraints. Local congestion includes all energy charges or credits incurred to serve a specific load, zone or load aggregate. Local congestion calculations account for the total difference between what the specified load pays and what the generation that serves that load is paid, regardless of whether the zone is a net importer or a net exporter of generation.

Local congestion is calculated on a constraint specific basis. Congestion is the total congestion payments by load at the buses within a defined area minus total CLMP credits received by generation that supplied that load, given the transmission constraints. Congestion reflects the underlying characteristics of the entire power system as it affects the defined area, including the nature and capability of transmission facilities, the offers and geographic distribution of generation facilities, the level and geographic distribution of decrement bids and increment offers and the geographic and temporal distribution of load.

On a system wide basis, congestion results from transmission constraints that prevent the lowest cost generation from serving some load that must be served by higher cost generation.

The total congestion caused by a constraint is equal to the product of the constraint shadow price times the net flow on the binding constraint. (The shadow price is the difference between the CLMPs across the constraint.) Total congestion caused by the constraint can also be calculated using the CLMPs caused by the constraint at every bus and the net MW injections or MW withdrawals at every affected bus. Congestion associated with a specific constraint is equal to load CLMP charges (CLMP of that specific constraint at each bus times load MW at each bus) caused by that constraint in excess of generation CLMP credits (CLMP of that specific constraint at each bus times generation MW at each bus) caused by that constraint. Equivalently, total congestion caused by the constraint can also be calculated by the shadow price of the constraint times the market flow on that constraint.

Congestion paid by zonal load is a function of the load share of the total load market flow on all binding constraints. Congestion is the difference between what load pays for energy due to binding transmission constraints and what generation, whether inside or outside the load's zone, is paid to serve that load. This calculation is done for both day-ahead congestion and balancing congestion.

Table 11-17 and Table 11-18 show day-ahead and balancing congestion by zone and the proportion of congestion resulting from constraints that are external to or internal to each zone, in the first three months of 2026 and 2025. Constraints are internal to a zone if both the source and sink points of the constraint are in the zone. DOM had the largest zonal congestion costs among all control zones in the first three months of 2026. DOM had $356.7 million in zonal congestion costs, comprised of $407.7 million in zonal day-ahead congestion costs and -$51.0 million in zonal balancing congestion costs. The Bedington Transformer, the Pruntytown Transformer, the Bedington – Black Oak Interface, the Pruntytown Circuit Breaker, and the Conastone – Northwest Line contributed $240.5 million, or 67.4 percent of the DOM zonal congestion costs.[25]

25 For additional information about the top 20 constraints that affected each zone, see the *2019 Annual State of the Market Report for PJM*, Appendix F: Congestion and Marginal Losses.

Table 11-17 CLMP credits and charges and total congestion revenue collected by zone (Dollars (Millions)): January through March, 2026[26]

	CLMP Credits and Charges (Millions)										
	Day-Ahead				Balancing				Congestion Costs		
Control Zone	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Internal to Zone	External to Zone	Grand Total
ACEC	$5.9	($17.3)	$0.3	$23.5	($0.4)	$1.6	($0.9)	($2.9)	$0.0	$20.6	$20.6
AEP	$104.8	($253.7)	$4.8	$363.3	($4.5)	$21.4	($14.3)	($40.2)	$5.3	$317.7	$323.1
APS	$49.9	($120.4)	$2.1	$172.4	($2.4)	$11.2	($6.8)	($20.4)	$83.5	$67.5	$152.0
ATSI	$42.0	($103.6)	$2.2	$147.8	($1.8)	$8.3	($6.3)	($16.4)	$0.7	$130.7	$131.5
BGE	$35.0	($81.2)	($1.4)	$114.9	($1.0)	$6.6	($3.4)	($11.0)	$7.8	$96.1	$103.9
COMED	$58.5	($142.4)	$1.8	$202.7	($0.9)	$12.1	($6.3)	($19.4)	$5.2	$178.2	$183.3
DAY	$12.1	($29.7)	$0.6	$42.4	($0.5)	$2.2	($1.7)	($4.4)	$0.0	$38.0	$38.0
DOM	$126.6	($277.2)	$4.0	$407.7	($4.9)	$31.1	($15.0)	($51.0)	$13.2	$343.5	$356.7
DPL	$13.0	($47.3)	$0.9	$61.2	($2.2)	$2.3	($3.0)	($7.6)	$5.4	$48.3	$53.6
DUKE	$18.5	($44.9)	$0.8	$64.2	($0.8)	$3.3	($2.5)	($6.7)	$0.0	$57.5	$57.5
DUQ	$8.0	($19.8)	$0.4	$28.2	($0.4)	$1.6	($1.2)	($3.2)	$0.0	$24.9	$25.0
EKPC	$13.7	($32.3)	$0.4	$46.4	($0.7)	$2.6	($1.6)	($4.9)	$0.0	$41.5	$41.5
EXT	$8.3	($18.9)	$0.5	$27.7	($1.1)	$4.3	($2.3)	($7.6)	$1.0	$19.1	$20.1
JCPLC	$15.9	($46.9)	$0.9	$63.7	($1.2)	$4.3	($2.6)	($8.2)	$0.0	$55.5	$55.5
MEC	$10.5	($31.0)	$0.5	$41.9	($0.8)	$2.7	($1.6)	($5.2)	$1.3	$35.5	$36.8
OVEC	$0.9	($2.2)	$0.1	$3.2	($0.0)	$0.2	($0.1)	($0.3)	$0.0	$2.8	$2.8
PE	$11.8	($29.3)	$0.5	$41.6	($0.7)	$2.4	($1.7)	($4.9)	$2.0	$34.8	$36.7
PECO	$24.7	($73.1)	$1.1	$99.0	($2.0)	$6.8	($4.0)	($12.8)	$1.2	$84.9	$86.1
PEPCO	$33.2	($76.8)	($1.3)	$108.7	($1.0)	$6.3	($3.1)	($10.5)	$0.0	$98.2	$98.2
PPL	$28.2	($86.7)	$1.3	$116.1	($2.7)	$7.7	($4.5)	($15.0)	$8.0	$93.2	$101.2
PSEG	$25.5	($74.2)	$1.4	$101.1	($1.9)	$6.7	($4.2)	($12.8)	$1.2	$87.1	$88.3
REC	$0.8	($2.3)	$0.0	$3.1	($0.1)	$0.2	($0.1)	($0.4)	$0.0	$2.8	$2.8
Total	$647.8	($1,610.9)	$22.0	$2,280.7	($32.1)	$146.0	($87.3)	($265.5)	$135.7	$1,878.5	$2,015.2

26 This table is affected by the identified distribution factor error.

Table 11-18 CLMP credits and charges and total congestion revenue collected by zone (Dollars (Millions)): January through March, 2025

	CLMP Credits and Charges (Millions)										
	Day-Ahead				Balancing				Congestion Costs		
Control Zone	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Internal to Zone	External to Zone	Grand Total
ACEC	$1.2	($4.8)	$0.4	$6.4	($0.3)	$0.9	($0.9)	($2.1)	$0.0	$4.2	$4.3
AEP	$25.6	($78.4)	$7.1	$111.1	($3.4)	$11.0	($14.7)	($29.2)	$12.7	$69.2	$81.9
APS	$18.4	($40.2)	$3.0	$61.6	($2.2)	$5.9	($7.2)	($15.3)	$6.9	$39.4	$46.3
ATSI	$14.1	($37.7)	$3.1	$54.9	($1.2)	$4.7	($6.6)	($12.5)	$0.5	$41.9	$42.4
BGE	$4.9	($19.6)	$1.7	$26.2	($1.0)	$3.0	($3.9)	($7.9)	$1.8	$16.5	$18.3
COMED	$7.5	($48.4)	$3.2	$59.1	($0.6)	$6.5	($7.5)	($14.6)	$5.2	$39.3	$44.5
DAY	$2.0	($9.7)	$0.8	$12.4	($0.3)	$1.1	($1.7)	($3.1)	$0.0	$9.3	$9.3
DOM	$24.2	($82.4)	$7.5	$114.1	($4.6)	$16.2	($18.6)	($39.5)	$9.2	$65.4	$74.6
DPL	$8.6	($11.4)	$0.9	$21.0	($2.9)	$2.2	($1.4)	($6.5)	$5.6	$8.8	$14.5
DUKE	$3.0	($13.7)	$1.2	$17.9	($0.5)	$1.7	($2.6)	($4.7)	$0.0	$13.2	$13.2
DUQ	$2.3	($5.0)	$0.5	$7.8	($0.3)	$0.9	($1.3)	($2.5)	$0.0	$5.3	$5.3
EKPC	$2.3	($9.4)	$0.8	$12.5	($0.5)	$1.4	($1.8)	($3.6)	$0.0	$8.8	$8.9
EXT	$3.0	($9.6)	$1.0	$13.6	($1.3)	$3.1	($3.4)	($7.8)	$0.9	$4.8	$5.8
JCPLC	$6.7	($12.6)	$1.1	$20.3	($0.8)	$2.5	($2.7)	($5.9)	$0.4	$14.0	$14.4
MEC	$5.1	($10.3)	$0.6	$16.0	($1.2)	$1.7	($1.6)	($4.5)	$0.5	$10.9	$11.4
OVEC	$0.2	($0.7)	$0.8	$1.6	($0.0)	$0.1	($0.1)	($0.2)	$0.7	$0.7	$1.4
PE	$5.1	($10.1)	$0.7	$15.9	($0.5)	$1.4	($1.8)	($3.7)	$4.6	$7.5	$12.1
PECO	$5.1	($21.5)	$1.7	$28.3	($1.3)	$3.8	($4.1)	($9.2)	$1.3	$17.8	$19.1
PEPCO	$4.8	($18.2)	$1.6	$24.5	($1.0)	$2.9	($3.6)	($7.4)	$0.1	$17.0	$17.1
PPL	$11.8	($27.9)	$1.9	$41.6	($1.4)	$4.2	($4.5)	($10.2)	$1.5	$29.9	$31.4
PSEG	$9.2	($24.5)	$1.9	$35.5	($1.3)	$3.8	($4.3)	($9.4)	$0.6	$25.5	$26.1
REC	$0.3	($0.7)	$0.1	$1.1	($0.0)	$0.1	($0.1)	($0.3)	$0.1	$0.7	$0.8
Total	$165.3	($496.6)	$41.7	$703.5	($26.7)	$79.1	($94.5)	($200.2)	$52.8	$450.5	$503.3

In cases where PJM has used an artificial constraint that causes net negative congestion and/or there is no load bus on the constrained side of a binding constraint, the congestion of the artificial constraint is handled as a special case. In the first three months of 2026, the total congestion costs associated with these special cases were -$3.5 million or 0.2 percent of the total congestion costs. Table 11-17 and Table 11-18 include congestion allocations from these special case artificial constraints.

There are five categories of artificial constraint based specific allocation special cases that can cause negative congestion: congestion associated with artificial constraints with no downstream load bus (no load bus); congestion associated with artificial constraints with downstream load buses with zero value CLMPs (zero CLMP); congestion associated with closed loop interfaces (closed loop interfaces); congestion associated with CT price setting logic (CT price setting logic); and congestion associated with nontransmission artificial facility constraints in the day-ahead energy market and/or any unaccounted for difference between PJM billed CLMP charges and calculated congestion costs including rounding errors (unclassified).[27]

27 While CT pricing logic was officially discontinued by PJM on September 1, 2021, PJM continued to use a related logic to force inflexible units to be on the margin in both real time and day ahead. These results have been included in the CT Pricing Logic totals.

Table 11-19 and Table 11-20 show total congestion by type of special case, congestion, and total congestion by zone. Closed loop interfaces and CT pricing logic, and similar artificial constraints employed by PJM to force resources to be marginal, generally result in negative congestion on a constraint specific basis. PJM's use of both the closed loop interfaces and CT Pricing Logic forces the affected resource bus LMP to match the marginal offer of the resource. This causes higher CLMP payments to the affected generation than the CLMP load charges to any affected load, resulting in negative congestion associated with the constraint. None of the closed loop interfaces were binding in the first three months of 2025 or 2026. The congestion associated with Real-Time Short-Term Marginal Value Overrides is included in the Normal Constraint Congestion totals.

Table 11-19 CLMP charges and credits and total congestion collected by zone and special case logic (Dollars (Millions)): January through March, 2026[28]

	CLMP Credits and Charges (Millions)																
	Day-Ahead							Balancing									
Control Zone	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Normal Constraint Congestion	Total	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Normal Constraint Congestion	Total	Grand Total	Special Cases Total	Percent of Special Cases
ACEC	$0.0	($0.1)	$0.0	$0.0	$0.0	$23.5	$23.5	$0.0	($0.0)	$0.0	$0.0	($0.0)	($2.9)	($2.9)	$20.6	($0.1)	(0.3%)
AEP	$0.0	($1.1)	$0.0	$0.0	$0.4	$364.0	$363.3	$0.0	($0.2)	$0.0	$0.0	($0.0)	($40.0)	($40.2)	$323.1	($0.9)	(0.3%)
APS	$0.0	($0.5)	$0.0	($0.0)	$0.2	$172.7	$172.4	$0.0	($0.1)	$0.0	$0.0	($0.0)	($20.2)	($20.4)	$152.0	($0.5)	(0.3%)
ATSI	$0.0	($0.4)	$0.0	$0.0	$0.2	$148.1	$147.8	$0.0	($0.1)	$0.0	$0.0	($0.0)	($16.3)	($16.4)	$131.5	($0.3)	(0.3%)
BGE	($0.0)	($0.3)	$0.0	($0.0)	$0.1	$115.0	$114.9	$0.0	($0.1)	$0.0	$0.0	($0.0)	($10.9)	($11.0)	$103.9	($0.2)	(0.2%)
COMED	$0.6	($0.7)	$0.0	$0.8	$0.2	$201.8	$202.7	$0.0	($0.2)	$0.0	$0.0	($0.0)	($19.2)	($19.4)	$183.3	$0.7	0.4%
DAY	$0.0	($0.1)	$0.0	$0.0	$0.0	$42.5	$42.4	$0.0	($0.0)	$0.0	$0.0	($0.0)	($4.4)	($4.4)	$38.0	($0.1)	(0.3%)
DOM	($0.0)	($1.1)	$0.0	$0.0	$0.4	$408.4	$407.7	$0.0	($0.3)	$0.0	$0.0	($0.0)	($50.7)	($51.0)	$356.7	($0.9)	(0.3%)
DPL	$0.0	($0.2)	$0.0	$0.0	$0.1	$61.3	$61.2	$0.0	($0.0)	$0.0	$0.0	($0.0)	($7.5)	($7.6)	$53.6	($0.2)	(0.3%)
DUKE	$0.0	($0.2)	$0.0	($0.0)	$0.1	$64.3	$64.2	$0.0	($0.0)	$0.0	$0.0	($0.0)	($6.6)	($6.7)	$57.5	($0.2)	(0.3%)
DUQ	$0.0	($0.1)	$0.0	$0.0	$0.0	$28.2	$28.2	$0.0	($0.0)	$0.0	$0.0	($0.0)	($3.2)	($3.2)	$25.0	($0.1)	(0.3%)
EKPC	$0.0	($0.1)	$0.0	$0.0	$0.1	$46.5	$46.4	$0.0	($0.0)	$0.0	$0.0	($0.0)	($4.9)	($4.9)	$41.5	($0.1)	(0.3%)
EXT	$0.9	($0.1)	$0.0	$0.0	$0.0	$26.8	$27.7	$0.0	($0.1)	$0.0	$0.0	$0.0	($7.6)	($7.6)	$20.1	$0.9	4.4%
JCPLC	$0.0	($0.2)	$0.0	$0.0	$0.1	$63.9	$63.7	$0.0	($0.0)	$0.0	$0.0	($0.0)	($8.1)	($8.2)	$55.5	($0.2)	(0.4%)
MEC	($0.0)	($0.1)	$0.0	$0.0	$0.0	$42.0	$41.9	$0.0	($0.0)	$0.0	$0.0	($0.0)	($5.1)	($5.2)	$36.8	($0.1)	(0.2%)
OVEC	$0.0	($0.0)	$0.0	$0.0	$0.0	$3.1	$3.2	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.3)	($0.3)	$2.8	$0.0	1.0%
PE	($0.0)	($0.1)	$0.0	$0.0	$0.0	$41.7	$41.6	$0.0	($0.0)	$0.0	$0.0	($0.0)	($4.8)	($4.9)	$36.7	($0.1)	(0.3%)
PECO	$0.0	($0.3)	$0.0	$0.0	$0.1	$99.2	$99.0	$0.0	($0.1)	$0.0	$0.0	($0.0)	($12.8)	($12.8)	$86.1	($0.3)	(0.3%)
PEPCO	($0.0)	($0.2)	$0.0	$0.0	$0.1	$108.8	$108.7	$0.0	($0.1)	$0.0	$0.0	($0.0)	($10.4)	($10.5)	$98.2	($0.2)	(0.2%)
PPL	$0.0	($0.4)	$0.0	$0.0	$0.1	$116.4	$116.1	$0.0	($0.1)	$0.0	$0.0	($0.0)	($14.9)	($15.0)	$101.2	($0.3)	(0.3%)
PSEG	$0.0	($0.3)	$0.0	$0.0	$0.1	$101.3	$101.1	$0.0	($0.1)	$0.0	$0.0	($0.0)	($12.7)	($12.8)	$88.3	($0.3)	(0.3%)
REC	$0.0	($0.0)	$0.0	$0.0	$0.0	$3.2	$3.1	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.4)	($0.4)	$2.8	($0.0)	(0.3%)
Total	$1.5	($6.8)	$0.0	$1.0	$2.4	$2,282.5	$2,280.7	$0.0	($1.6)	$0.0	$0.0	($0.0)	($263.9)	($265.5)	$2,015.2	($3.5)	(0.2%)

28 This table is affected by the identified distribution factor error.

Table 11-20 CLMP charges and credits and congestion collected by zone and special case logic (Dollars (Millions)): January through March, 2025

	CLMP Credits and Charges (Millions)																
	Day-Ahead							Balancing									
Control Zone	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Normal Constraint Congestion	Total	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Normal Constraint Congestion	Total	Grand Total	Special Cases Total	Percent of Special Cases
ACEC	$0.0	($0.1)	$0.0	$0.0	($0.0)	$6.5	$6.4	$0.0	$0.0	$0.0	$0.0	$0.0	($2.1)	($2.1)	$4.3	($0.1)	($0.0)
AEP	($0.0)	($1.8)	$0.0	$0.2	($0.0)	$112.6	$111.1	$0.0	$0.0	$0.0	$0.0	$0.0	($29.2)	($29.2)	$81.9	($1.5)	($0.0)
APS	($0.0)	($0.9)	$0.0	$0.0	($0.0)	$62.4	$61.6	$0.0	$0.0	$0.0	$0.0	$0.0	($15.3)	($15.3)	$46.3	($0.9)	($0.0)
ATSI	($0.0)	($0.6)	$0.0	$0.1	($0.0)	$55.5	$54.9	$0.0	($0.0)	$0.0	$0.0	$0.0	($12.5)	($12.5)	$42.4	($0.6)	($0.0)
BGE	($0.0)	($0.4)	$0.0	$0.0	($0.0)	$26.7	$26.2	$0.0	$0.0	$0.0	$0.0	$0.0	($7.9)	($7.9)	$18.3	($0.4)	($0.0)
COMED	$0.0	($1.3)	$0.0	$0.6	($0.0)	$59.8	$59.1	$0.0	$0.0	$0.0	$0.0	$0.0	($14.6)	($14.6)	$44.5	($0.7)	($0.0)
DAY	($0.0)	($0.2)	$0.0	$0.0	($0.0)	$12.7	$12.4	$0.0	$0.0	$0.0	$0.0	$0.0	($3.1)	($3.1)	$9.3	($0.2)	($0.0)
DOM	($0.0)	($1.7)	$0.0	$0.0	($0.0)	$115.7	$114.1	$0.0	$0.0	$0.0	$0.0	$0.0	($39.5)	($39.5)	$74.6	($1.7)	($0.0)
DPL	$0.0	($0.3)	$0.0	$0.0	($0.0)	$21.3	$21.0	$0.0	$0.0	$0.0	$0.0	$0.0	($6.5)	($6.5)	$14.5	($0.3)	($0.0)
DUKE	($0.0)	($0.3)	$0.0	$0.0	($0.0)	$18.3	$17.9	$0.0	$0.0	$0.0	$0.0	$0.0	($4.7)	($4.7)	$13.2	($0.3)	($0.0)
DUQ	($0.0)	($0.2)	$0.0	$0.0	($0.0)	$8.0	$7.8	$0.0	$0.0	$0.0	$0.0	$0.0	($2.5)	($2.5)	$5.3	($0.2)	($0.0)
EKPC	($0.0)	($0.3)	$0.0	$0.0	($0.0)	$12.8	$12.5	$0.0	$0.0	$0.0	$0.0	$0.0	($3.6)	($3.6)	$8.9	($0.3)	($0.0)
EXT	$0.8	($0.2)	$0.0	$0.0	($0.0)	$13.0	$13.6	$0.0	($0.0)	$0.0	$0.0	$0.0	($7.8)	($7.8)	$5.8	$0.6	$0.1
JCPLC	$0.4	($0.4)	$0.0	$0.0	($0.0)	$20.3	$20.3	$0.0	$0.0	$0.0	$0.0	$0.0	($5.9)	($5.9)	$14.4	$0.1	$0.0
MEC	($0.0)	($0.2)	$0.0	$0.1	($0.0)	$16.1	$16.0	$0.0	$0.0	$0.0	$0.0	$0.0	($4.5)	($4.5)	$11.4	($0.1)	($0.0)
OVEC	($0.0)	($0.0)	$0.0	$0.7	($0.0)	$0.9	$1.6	$0.0	($0.0)	$0.0	$0.0	$0.0	($0.2)	($0.2)	$1.4	$0.7	$0.5
PE	($0.0)	($0.2)	$0.0	$0.0	($0.0)	$16.1	$15.9	$0.0	$0.0	$0.0	$0.0	$0.0	($3.7)	($3.7)	$12.1	($0.2)	($0.0)
PECO	$0.0	($0.6)	$0.0	$0.4	($0.0)	$28.5	$28.3	$0.0	$0.0	$0.0	$0.0	$0.0	($9.2)	($9.2)	$19.1	($0.2)	($0.0)
PEPCO	($0.0)	($0.4)	$0.0	$0.0	($0.0)	$24.9	$24.5	$0.0	$0.0	$0.0	$0.0	$0.0	($7.4)	($7.4)	$17.1	($0.4)	($0.0)
PPL	$0.0	($0.6)	$0.0	$0.0	($0.0)	$42.3	$41.6	$0.0	$0.0	$0.0	$0.0	$0.0	($10.2)	($10.2)	$31.4	($0.6)	($0.0)
PSEG	$0.0	($0.6)	$0.0	$0.0	($0.0)	$36.1	$35.5	$0.0	$0.0	$0.0	$0.0	$0.0	($9.4)	($9.4)	$26.1	($0.6)	($0.0)
REC	($0.0)	($0.0)	$0.0	$0.0	($0.0)	$1.1	$1.1	$0.0	$0.0	$0.0	$0.0	$0.0	($0.3)	($0.3)	$0.8	($0.0)	($0.0)
Total	$1.2	($11.3)	$0.0	$2.1	($0.0)	$711.5	$703.5	$0.0	$0.0	$0.0	$0.0	$0.0	($200.3)	($200.2)	$503.3	($7.9)	($0.0)

Table 11-21 show total balancing congestion caused by each of the Real-Time Short-Term Marginal Value Overrides constraints PJM used in the first three months of 2026 (Table 11-21). The congestion associated with Real-Time Short-Term Marginal Value Overrides is included in the Normal Constraint Congestion totals. Real-Time Short-Term Marginal Value Overrides are artificial transmission contingencies on physical transmission elements. Real-Time Short-Term Marginal Value Overrides temporarily force a generator to be marginal. Real-Time Short-Term Marginal Value Overrides are typically in place for a period of from several hours to a few days. Real-Time Short-Term Marginal Value Overrides are similar to a closed loop interface in that they enforce artificially uniform price effects, but unlike closed loop interfaces that only affect prices on the constrained side, these artificial constraints enforce artificially uniform price spreads between the two sides of the constraint through large uniform dfax on the constrained side and small uniform dfax on the unconstrained side. The uniform source dfax and uniform sink dfax of the artificial constraint can be modified, along with the transmission line limits, by PJM to meet market outcome goals and are a source of significant modeling differences between the day-ahead and real-time market.

Table 11-21 CLMP charges and credits and congestion collected by Real-Time Short-Term Marginal Value Overrides by affected Constraint: January through March, 2026[29]

				CLMP Credits and Charges (Millions)				Percent of Total Congestion Caused by Real-Time Short-Term Marginal Value Overrides
				Balancing				
No.	Constraint	Type	Location	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	
1	Piney Grove - Wattsville	Line	DPL	(0.1)	0.0	(0.0)	(0.1)	55.5%
2	Carlisle Pike - Gardners	Line	PE	(0.1)	0.0	(0.0)	(0.1)	44.5%
3	Bellehaven - Kellam	Line	DPL	(0.0)	(0.0)	0.0	0.0	0.0%
	Total			($0.2)	$0.1	($0.0)	($0.2)	100.0%

Fast Start Pricing Effect on Zonal Congestion

PJM implemented fast start pricing in both day-ahead and real-time markets starting September 1, 2021. Table 11-22 compares the congestion costs between the dispatch run and the pricing run in the first three months of 2026. The table shows that the implementation of fast starting pricing logic caused day-ahead total congestion costs to decrease $622.3 million (or 21.4 percent), caused negative balancing congestion costs to decrease $14.0 million (or 5.6 percent), and caused total congestion costs to decrease $636.3 million (or 24.0 percent) from the dispatch run to the pricing run in the first three months of 2026. In comparing the two pricing results, the same MW, from the dispatch run in the day-ahead market and metered output in the real-time market, are used in the accounting cost calculations.

Table 11-22 Total congestion by dispatch and pricing run (Dollars (Millions)): January through March, 2026[30]

	Congestion Costs (Millions)								
	Dispatch Run			Pricing Run			Difference		
Control Zone	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total
ACEC	$27.5	($2.7)	$24.7	$23.5	($2.9)	$20.6	($4.0)	($0.1)	($4.1)
AEP	$439.1	($38.0)	$401.0	$363.3	($40.2)	$323.1	($75.8)	($2.2)	($78.0)
APS	$207.3	($19.0)	$188.3	$172.4	($20.4)	$152.0	($34.9)	($1.4)	($36.3)
ATSI	$177.5	($15.5)	$162.0	$147.8	($16.4)	$131.5	($29.7)	($0.9)	($30.6)
BGE	$223.2	($10.4)	$212.8	$114.9	($11.0)	$103.9	($108.3)	($0.6)	($108.9)
COMED	$243.4	($18.3)	$225.1	$202.7	($19.4)	$183.3	($40.7)	($1.0)	($41.7)
DAY	$51.2	($4.2)	$47.1	$42.4	($4.4)	$38.0	($8.9)	($0.2)	($9.1)
DOM	$494.4	($48.4)	$446.1	$407.7	($51.0)	$356.7	($86.7)	($2.6)	($89.3)
DPL	$71.3	($7.0)	$64.3	$61.2	($7.6)	$53.6	($10.1)	($0.6)	($10.7)
DUKE	$77.8	($6.3)	$71.5	$64.2	($6.7)	$57.5	($13.6)	($0.4)	($14.0)
DUQ	$33.8	($3.0)	$30.8	$28.2	($3.2)	$25.0	($5.7)	($0.2)	($5.8)
EKPC	$58.1	($4.6)	$53.4	$46.4	($4.9)	$41.5	($11.6)	($0.3)	($11.9)
EXT	$33.5	($7.2)	$26.2	$27.7	($7.6)	$20.1	($5.8)	($0.4)	($6.1)
JCPLC	$74.1	($7.8)	$66.3	$63.7	($8.2)	$55.5	($10.4)	($0.4)	($10.7)
MEC	$49.3	($4.9)	$44.4	$41.9	($5.2)	$36.8	($7.4)	($0.2)	($7.6)
OVEC	$3.8	($0.3)	$3.5	$3.2	($0.3)	$2.8	($0.7)	($0.0)	($0.7)
PE	$49.7	($4.6)	$45.0	$41.6	($4.9)	$36.7	($8.1)	($0.2)	($8.3)
PECO	$116.6	($12.3)	$104.3	$99.0	($12.8)	$86.1	($17.6)	($0.6)	($18.1)
PEPCO	$212.4	($9.9)	$202.5	$108.7	($10.5)	$98.2	($103.7)	($0.6)	($104.2)
PPL	$137.1	($14.3)	$122.8	$116.1	($15.0)	$101.2	($20.9)	($0.6)	($21.6)
PSEG	$118.5	($12.3)	$106.2	$101.1	($12.8)	$88.3	($17.4)	($0.6)	($17.9)
REC	$3.7	($0.4)	$3.3	$3.1	($0.4)	$2.8	($0.5)	($0.0)	($0.6)
Total	$2,903.0	($251.5)	$2,651.5	$2,280.7	($265.5)	$2,015.2	($622.3)	($14.0)	($636.3)

Monthly Congestion

Table 11-23 shows day-ahead, balancing and inadvertent congestion costs by month for January 2025 through March 2026.

Total negative balancing congestion costs in the first three months of 2026, were highest in January. The top constraint that contributed to the total balancing congestion costs in the first three months of 2026 was the Pruntytown Circuit Breaker. The constraint accounted for 12.7 percent of the total balancing congestion costs in the first three months of 2026. The majority (74.0 percent)

29 This table is affected by the identified distribution factor error.

30 This table is affected by the identified distribution factor error.

of negative balancing congestion costs for the Pruntytown Circuit Breaker were the result of Generation.

In the first three months of 2026, total congestion costs were highest in January and lowest in March.

Table 11-23 Monthly congestion costs by market (Dollars (Millions)): January 2025 through March 2026

	Congestion Costs (Millions)							
	2025				2026			
	Day-Ahead	Balancing	Inadvertent Charges	Total	Day-Ahead	Balancing	Inadvertent Charges	Total
Jan	$361.5	($133.8)	($0.0)	$227.8	$1,341.1	($135.4)	$0.0	$1,205.7
Feb	$146.5	($22.0)	($0.0)	$124.5	$740.1	($101.9)	$0.0	$638.2
Mar	$195.5	($44.4)	($0.0)	$151.0	$199.5	($28.2)	$0.0	$171.4
Apr	$185.7	($24.2)	($0.0)	$161.6				
May	$253.4	($15.7)	($0.0)	$237.7				
Jun	$423.6	($61.5)	($0.0)	$362.2				
Jul	$625.4	($16.5)	($0.0)	$608.9				
Aug	$176.8	($26.3)	$0.0	$150.4				
Sep	$235.1	($25.4)	($0.0)	$209.8				
Oct	$386.3	($34.4)	($0.0)	$351.9				
Nov	$222.6	($28.2)	($0.0)	$194.5				
Dec	$437.8	($44.5)	($0.0)	$393.3				
Total	$3,650.4	($476.9)	($0.0)	$3,173.5	$2,280.7	($265.5)	$0.0	$2,015.2

Figure 11-3 shows PJM monthly total congestion cost for January 2008 through March 2026.

Figure 11-3 Monthly total congestion cost (Dollars (Millions)): January 2008 through March 2026

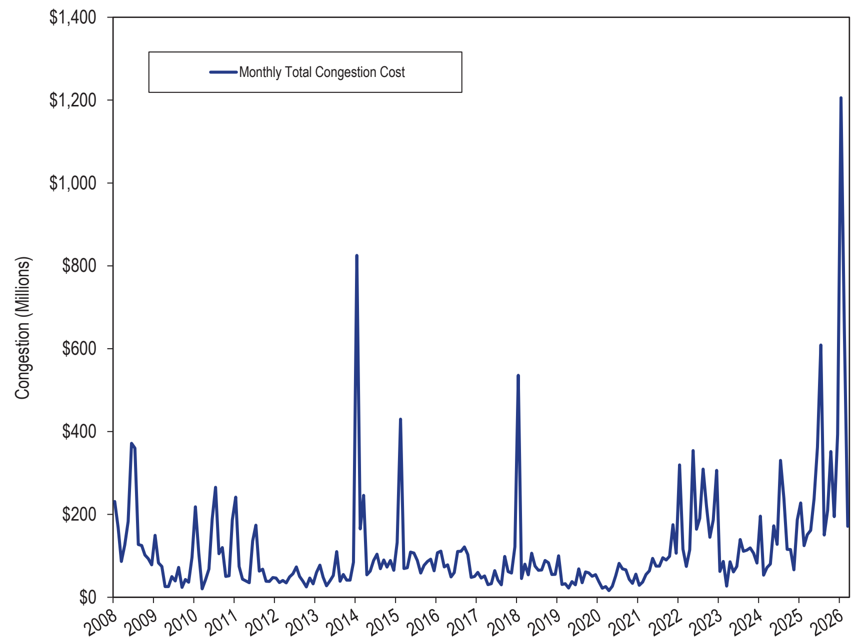


Table 11-24 shows monthly total CLMP credits and charges for each virtual transaction type for anuary 2025 through March 2026. Virtual transaction CLMP charges, when positive, are the total CLMP charges to the virtual transactions and when negative, are the total CLMP credits to the virtual transactions. The negative totals in Table 11-24 show that virtuals were paid, in net, CLMP credits in the first three months of 2026 and 2025. In the first three months of 2026, 34.3 percent of the total credits to virtuals went to UTCs, compared to 48.1 percent in the first three months of 2025. In the first three months of 2026, the average hourly cleared UTC MW decreased by 25.8 percent, compared to the first three months of 2026.

Table 11-24 Monthly CLMP charges by virtual transaction type (Dollars (Millions)): January 2025 through March 2026

		CLMP Credits and Charges (Millions)									
		DEC			INC			Up to Congestion			
Year		Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
2025	Jan	$3.3	($31.1)	($27.8)	$22.3	($35.9)	($13.6)	$16.8	($50.6)	($33.8)	($75.1)
	Feb	($5.2)	$4.2	($1.0)	$12.7	($17.4)	($4.7)	$11.2	($14.9)	($3.7)	($9.4)
	Mar	($2.3)	$2.2	($0.1)	$22.4	($29.5)	($7.1)	$14.2	($27.0)	($12.9)	($20.1)
	Apr	($0.8)	$0.6	($0.2)	$20.8	($26.9)	($6.1)	$6.4	($16.5)	($10.1)	($16.5)
	May	($0.6)	($5.0)	($5.6)	$13.7	($15.2)	($1.5)	$6.7	($7.7)	($0.9)	($8.1)
	Jun	($3.3)	($6.3)	($9.7)	$9.9	($19.9)	($10.0)	$18.9	($39.5)	($20.6)	($40.2)
	Jul	($8.4)	$0.8	($7.6)	$12.0	($13.6)	($1.6)	$8.3	($11.0)	($2.7)	($11.9)
	Aug	$0.1	($10.4)	($10.3)	$4.7	($7.6)	($2.9)	$6.4	($8.2)	($1.9)	($15.1)
	Sep	($7.7)	$2.9	($4.9)	$10.0	($11.1)	($1.2)	$11.0	($14.8)	($3.9)	($9.9)
	Oct	($15.7)	$18.1	$2.5	$24.8	($39.6)	($14.8)	$18.4	($30.9)	($12.4)	($24.7)
	Nov	($9.7)	$4.4	($5.3)	$13.5	($22.6)	($9.1)	$10.2	($13.1)	($2.8)	($17.2)
	Dec	$4.8	($26.4)	($21.6)	$5.7	($12.2)	($6.5)	$8.5	($16.3)	($7.9)	($36.0)
	Total	($45.6)	($46.0)	($91.6)	$172.5	($251.6)	($79.1)	$137.0	($250.5)	($113.5)	($284.2)
2026	Jan	($4.8)	($13.0)	($17.8)	$43.6	($71.2)	($27.7)	$1.4	($42.9)	($41.5)	($87.0)
	Feb	($3.3)	($27.2)	($30.5)	$42.1	($69.9)	($27.8)	$11.3	($22.9)	($11.6)	($69.9)
	Mar	($14.0)	$11.0	($3.1)	$13.4	($19.5)	($6.0)	$11.7	($17.5)	($5.8)	($14.9)
	Total	($22.2)	($29.2)	($51.4)	$99.0	($160.5)	($61.5)	$24.4	($83.2)	($58.8)	($171.7)

Congested Facilities

A congestion event exists when a unit or units must be dispatched out of merit order to control for the potential impact of a contingency on a monitored facility or to control an actual overload. A congestion event hour exists when a specific facility is constrained for one or more five-minute intervals within an hour. A congestion event hour differs from a constrained hour, which is any hour during which one or more facilities are congested. If two facilities are constrained during an hour, the result is one constrained hour and two congestion event hours. Constraints are often simultaneous, so the number of congestion event hours usually exceeds the number of constrained hours and the number of congestion event hours usually exceeds the number of hours in a year.

In order to have a consistent metric for real-time and day-ahead congestion frequency, real-time congestion frequency is measured using the convention that an hour is constrained if any of its component five-minute intervals is constrained. This is consistent with the way in which PJM reports real-time congestion.

In the first three months of 2026, there were 20,569 day-ahead congestion event hours compared to 20,824 day-ahead congestion event hours in the first three months of 2025. Of the day-ahead congestion event hours in the first three months of 2026, only 5,293 (25.7 percent) were also constrained in the real-time energy market (Table 11-26). In the first three months of 2026, there were 10,069 real-time, congestion event hours compared to 8,416 real-time, congestion event hours in the first three months of 2025. Of the real-time congestion event hours in the first three months of 2026, 4,900 (53.3 percent) were also constrained in the day-ahead energy market (Table 11-27).

Congestion Event Hours

Table 11-25 compares the monthly day-ahead and real-time congestion event hours in January 2025 to March 2026. Day-ahead congestion event hours are significantly greater than real-time congestion event hours.

Table 11-25 Monthly day-ahead and real-time congestion event hours: January 2025 through March 2026

	Day-Ahead Congestion Event Hours		Real-Time Congestion Event Hours	
	2025	2026	2025	2026
Jan	6,599	6,756	2,574	3,803
Feb	6,213	7,086	2,176	3,151
Mar	8,016	6,445	3,663	3,114
Apr	5,238		2,446	
May	4,653		1,738	
Jun	6,727		2,688	
Jul	6,835		2,256	
Aug	5,120		1,646	
Sep	6,985		2,469	
Oct	6,851		3,083	
Nov	6,170		2,420	
Dec	7,538		3,264	
Total	76,945	20,287	30,423	10,068

Table 11-26 and Table 11-27 compare day-ahead and real-time congestion event hours. Among the hours for which a facility is constrained in the day-ahead energy market, the number of hours during which the facility is also constrained in the real-time energy market are presented in Table 11-26.[31]

Among the hours for which a facility was constrained in the real-time energy market, the number of hours during which the facility was also constrained in the day-ahead energy market are presented in Table 11-27.

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 2026. The number of congestion event hours in the day-ahead energy market was about 2 times the number of congestion event hours in the real-time energy market.

31 Constraints are mapped to transmission facilities. In the day-ahead energy market, within a given hour, a single transmission facility may be associated with multiple constraints. In such situations, the same facility accounts for more than one congestion event hour for a given hour in the day-ahead energy market. Similarly in the real-time market a facility may account for more than one congestion event hour within a given hour.

In the real-time market, PJM has the ability to model and monitor almost all PJM transmission facilities. In the day-ahead market, PJM can model and monitor only a portion of PJM transmission facilities. This difference in modeling is the basis of false arbitrage and the source of significant virtual profits. While more constraints are modeled and monitored in the PJM real-time market than the day-ahead market, there is significantly more network flow in the day-ahead market than in the real-time market as a result of virtual bids and offers. Virtual bids and offers also contribute to day-ahead market flows that do not align with realized real-time physical flows. 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, despite the fact that only a portion of PJM transmission facilities are modeled in the day-ahead market.

Table 11-26 Congestion event hours (day-ahead against real-time): January through March, 2025 and 2026

	Congestion Event Hours					
	2025 (Jan - Mar)			2026 (Jan - Mar)		
Type	Day-Ahead Constrained	Corresponding Real-Time Constrained	Percent	Day-Ahead Constrained	Corresponding Real-Time Constrained	Percent
Flowgate	3,219	603	18.7%	3,818	764	20.0%
Interface	723	130	18.0%	515	141	27.4%
Line	13,379	2,699	20.2%	12,659	2,864	22.6%
Transformer	2,019	86	4.3%	2,030	710	35.0%
Other	1,484	710	47.8%	1,547	814	52.6%
Total	20,824	4,228	20.3%	20,569	5,293	25.7%

Table 11-27 Congestion event hours (real-time against day-ahead): January through March, 2025 and 2026

	Congestion Event Hours					
	2025 (Jan - Mar)			2026 (Jan - Mar)		
Type	Real-Time Constrained	Corresponding Day-Ahead Constrained	Percent	Real-Time Constrained	Corresponding Day-Ahead Constrained	Percent
Flowgate	1,488	599	40.3%	1,966	771	39.2%
Interface	316	157	49.7%	470	241	51.3%
Line	5,350	2,720	50.8%	5,504	2,914	52.9%
Transformer	343	86	25.1%	991	607	61.3%
Other	919	736	80.1%	1,138	829	72.8%
Total	8,416	4,298	51.1%	10,069	5,362	53.3%

Congestion by Facility Type and Voltage

Table 11-28 shows congestion costs by facility voltage class in first three months of 2026. Congestion costs in the first three months of 2026 increased for all facility voltage classes except for 130kV, 115kV, and 1kV compared to the first three months of 2025.

Table 11-28 Congestion summary (By facility voltage): January through March, 2026[32]

	CLMP Credits and Charges (Millions)										
	Day-Ahead				Balancing					Event Hours	
Voltage (kV)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs	Day-Ahead	Real-Time
765	$1.9	($8.1)	$1.7	$11.6	($0.0)	($0.1)	($0.0)	$0.0	$11.7	184	1
500	$423.1	($997.1)	($3.0)	$1,417.2	($22.0)	$132.5	($20.8)	($175.2)	$1,242.0	1,777	1,472
345	$8.3	($96.7)	$8.6	$113.6	($17.5)	($2.7)	($24.7)	($39.6)	$74.0	2,012	1,205
230	$176.9	($339.4)	$4.3	$520.7	$12.0	$15.3	($21.4)	($24.8)	$495.9	7,381	3,424
161	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	($0.0)	0	2
138	$14.9	($130.2)	$9.0	$154.1	($5.7)	$10.2	($18.1)	($34.0)	$120.1	6,802	3,157
130	$0.0	$0.0	$0.0	$0.0	($0.7)	($0.9)	($0.9)	($0.8)	($0.8)	0	57
115	$22.3	($27.3)	$0.7	$50.3	$2.6	($7.9)	($1.0)	$9.5	$59.8	1,718	583
69	($0.4)	($9.8)	$0.6	$10.0	($0.3)	($0.3)	($0.1)	($0.0)	$9.9	664	134
45	($0.0)	($0.2)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	6	0
13.8	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	25	0
1	$0.0	$0.0	$0.0	$0.0	($0.5)	($0.1)	($0.3)	($0.7)	($0.7)	0	34
Unclassified	$0.8	($2.2)	$0.1	$3.0	$0.0	$0.0	$0.0	($0.0)	$3.0	0	0
Total	$647.8	($1,610.9)	$22.0	$2,280.7	($32.1)	$146.0	($87.3)	($265.5)	$2,015.2	20,569	10,069

Table 11-29 Congestion summary (By facility voltage): January through March, 2025

	CLMP Credits and Charges (Millions)										
	Day-Ahead				Balancing					Event Hours	
Voltage (kV)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Costs	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Costs	Total	Congestion Costs	Day-Ahead	Real-Time
765	$2.3	($11.1)	$1.6	$15.0	($1.2)	$2.3	($3.9)	($7.4)	$7.5	142	76
500	$51.6	($139.8)	$11.5	$202.9	($22.0)	$57.8	($33.3)	($113.0)	$89.9	939	358
345	($8.7)	($50.8)	$1.9	$44.0	($4.9)	($1.7)	($7.3)	($10.5)	$33.5	1,728	737
230	$58.7	($101.6)	$8.8	$169.1	$9.3	($2.5)	($24.5)	($12.7)	$156.3	5,766	1,549
161	($0.1)	($0.4)	$0.0	$0.4	$0.0	$0.2	($0.2)	($0.4)	$0.0	17	15
138	$42.3	($93.5)	$15.8	$151.5	($19.2)	($1.4)	($23.3)	($41.1)	$110.4	7,239	3,503
130	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
115	$15.8	($97.3)	$1.8	$114.8	$14.0	$22.6	($2.2)	($10.8)	$104.0	3,594	1,920
69	$3.2	($0.6)	($0.0)	$3.8	($2.4)	$1.1	$0.4	($3.1)	$0.7	1,351	199
45	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
13.8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
1	$0.2	($1.6)	$0.2	$2.0	($0.4)	$0.5	($0.2)	($1.1)	$0.8	48	59
Unclassified	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
Total	$165.2	($496.6)	$41.7	$703.5	($26.7)	$79.1	($94.5)	($200.2)	$503.3	20,824	8,416

32 This table is affected by the identified distribution factor error.

Day-ahead, congestion event hours decreased on interfaces and lines and increased on flowgates and transformers in the first three months of 2026. Congestion event hours on lines decreased by 720 congestion event hours from 13,379 day-ahead, congestion event hours in the first three months of 2025 to 12,659 day-ahead congestion event hours in the first three months of 2026 (Table 11-30).

Real-time, congestion event hours increased on flowgates, interfaces, lines and transformers in the first three months of 2026 (Table 11-31). Lines increased by 154 congestion event hours from 5,350 real-time, congestion event hours in the first three months of 2025 to 5,504 real-time congestion event hours in the first three months of 2026.

Table 11-30 provides congestion event hour subtotals and congestion cost subtotals comparing the first three months of 2026 results by facility type: line, transformer, interface, flowgate and unclassified facilities.[33] [34]

Table 11-30 Congestion summary (By facility type): January through March, 2026[35]

	CLMP Credits and Charges (Millions)										
	Day-Ahead				Balancing					Event Hours	
Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs	Day-Ahead	Real-Time
Flowgate	$17.3	($158.4)	$20.3	$195.9	($17.2)	$9.3	($27.6)	($54.1)	$141.8	3,818	1,966
Interface	$148.2	($337.5)	($6.6)	$479.1	($7.4)	$65.1	($8.9)	($81.4)	$397.7	515	470
Line	$149.6	($386.3)	$8.5	$544.4	($9.1)	($2.1)	($40.7)	($47.7)	$496.7	12,659	5,504
Transformer	$196.1	($618.5)	($3.4)	$811.2	($11.2)	$39.3	($0.0)	($50.4)	$760.8	2,030	991
Other	$135.9	($108.0)	$3.2	$247.1	$9.6	$43.4	($10.2)	($44.0)	$203.1	1,547	1,138
Unclassified	$0.8	($2.2)	$0.1	$3.0	$0.0	$0.0	$0.0	($0.0)	$3.0	0	0
Total	$647.8	($1,610.9)	$22.0	$2,280.7	($35.2)	$155.0	($87.4)	($277.6)	$2,003.0	20,569	10,069

Table 11-31 Congestion summary (By facility type): January through March, 2025

	CLMP Credits and Charges (Millions)										
	Day-Ahead				Balancing					Event Hours	
Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs	Day-Ahead	Real-Time
Flowgate	($3.4)	($88.4)	$13.7	$98.7	($2.4)	$0.9	($7.2)	($10.5)	$88.2	3,219	1,488
Interface	$52.0	($130.4)	$11.4	$193.8	($21.9)	$58.4	($32.3)	($112.5)	$81.3	723	316
Line	$90.1	($237.1)	$12.5	$339.7	($8.2)	$18.0	($50.1)	($76.3)	$263.3	13,379	5,350
Transformer	$2.4	($33.2)	$2.1	$37.7	($1.5)	($0.4)	($1.0)	($2.1)	$35.6	2,019	343
Other	$24.0	($7.6)	$2.0	$33.6	$7.4	$2.3	($3.9)	$1.2	$34.8	1,484	919
Unclassified	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.0)	$0.0	$0.0	$0.0	0	0
Total	$165.3	($496.6)	$41.7	$703.5	($26.7)	$79.1	($94.5)	($200.2)	$503.3	20,824	8,416

33 Unclassified are congestion costs related to nontransmission facility constraints in the day-ahead energy market and any unaccounted for difference between PJM billed CLMP charges and calculated congestion costs including rounding errors. Nontransmission facility constraints include day-ahead market only constraints such as constraints on virtual transactions and constraints associated with phase-angle regulators.
34 The term flowgate refers to MISO reciprocal coordinated flowgates and NYISO M2M flowgates.
35 This table is affected by the identified distribution factor error.

Constraint Frequency

Table 11-32 lists the constraints in the first three months of 2025 and 2026 that were most frequently binding and Table 11-33 shows the constraints which experienced the largest change in congestion event hours from the first three months of 2025 to the first three months of 2026. In Table 11-32, constraints are presented in descending order of total day-ahead event hours and real-time event hours in the first three months of 2026. In Table 11-33, the constraints are presented in descending order of absolute value of day-ahead event hour changes plus real-time event hour changes from the first three months of 2025 to the first three months of 2026.

Table 11-32 Top 25 constraints: January through March, 2026[36]

			(Jan - Mar)												
			Congestion Event Hours						Percent of Annual Hours					
			Day-Ahead			Real-Time			Day-Ahead			Real-Time		
No.	Constraint	Type	2025	2026	Change	2025	2026	Change	2025	2026	Change	2025	2026	Change
1	East Towanda - Hillside	Line	444	1,667	1,223	66	1,303	1,237	20.6%	77%	57%	3%	60%	57%
2	Haumesser Road - Steward	Line	489	1,276	787	322	648	326	23%	59%	36%	15%	30%	15%
3	State Line - Roxana	Flowgate	0	550	550	0	547	547	0%	25%	25%	0%	25%	25%
4	Nottingham	Other	700	603	(97)	449	479	30	32%	28%	(4%)	21%	22%	1%
5	Bedington	Transformer	5	563	558	9	449	440	0%	26%	26%	0%	21%	20%
6	Burnham - Munster	Flowgate	0	1,002	1,002	0	0	0	0%	46%	46%	0%	0%	0%
7	Chicago Ave - Praxair	Flowgate	0	504	504	4	477	473	0%	23%	23%	0%	22%	22%
8	Kewanee	Other	676	466	(210)	445	414	(31)	31%	22%	(10%)	21%	19%	(1%)
9	Lenox - Macnew Tap	Line	0	495	495	0	309	309	0%	23%	23%	0%	14%	14%
10	Graceton - Manor	Line	260	520	260	77	242	165	12%	24%	12%	4%	11%	8%
11	Pruntytown	Transformer	0	414	414	0	256	256	0%	19%	19%	0%	12%	12%
12	Burnham - Munster	Line	0	0	0	0	633	633	0%	0%	0%	0%	29%	29%
13	Gardners - Texas Eastern	Line	457	554	97	70	68	(2)	21%	26%	4%	3%	3%	(0%)
14	Cedar Grove - Clifton	Line	328	528	200	17	83	66	15%	24%	9%	1%	4%	3%
15	Bedington - Black Oak	Interface	131	186	55	39	322	283	6%	9%	3%	2%	15%	13%
16	Eldred - Sunbury	Line	24	326	302	24	135	111	1%	15%	14%	1%	6%	5%
17	Kokomo - Tipton W	Flowgate	0	232	232	0	156	156	0%	11%	11%	0%	7%	7%
18	Cedar Creek - Silver Run	Line	103	259	156	3	107	104	5%	12%	7%	0%	5%	5%
19	Monroe - Lallendorf	Flowgate	166	270	104	157	91	(66)	8%	13%	5%	7%	4%	(3%)
20	Messick Road - Ridgeley	Line	17	215	198	0	122	122	1%	10%	9%	0%	6%	6%
21	Mahans Lane - Tidd	Line	139	150	11	72	185	113	6%	7%	1%	3%	9%	5%
22	Pruntytown	Other	0	150	150	0	180	180	0%	7%	7%	0%	8%	8%
23	Keystone - Shelocta	Line	102	313	211	0	0	0	5%	14%	10%	0%	0%	0%
24	Linden - VFT	Line	180	309	129	0	0	0	8%	14%	6%	0%	0%	0%
25	Conastone - Northwest	Line	173	163	(10)	66	118	52	8%	8%	(0%)	3%	5%	2%

36 This table is affected by the identified distribution factor error.

Table 11-33 Top 25 constraints year to year change in occurrence: January through March, 2025 and 2026[37]

			(Jan - Mar)												
			Congestion Event Hours						Percent of Annual Hours						
			Day-Ahead			Real-Time			Day-Ahead			Real-Time			
No.	Constraint	Type	2025	2026	Change	2025	2026	Change	2025	2026	Change	2025	2026	Change	
1	Lenox - North Meshoppen	Line	1,893	0	(1,893)	1,578	0	(1,578)	88%	0%	(88%)	73%	0%	(73%)	
2	East Towanda - Hillside	Line	444	1,667	1,223	66	1,303	1,237	21%	77%	57%	3%	60%	57%	
3	Dune Acres - Michigan City	Flowgate	1,305	0	(1,305)	31	0	(31)	60%	0%	(60%)	1%	0%	(1%)	
4	Haumesser Road - Steward	Line	489	1,276	787	322	648	326	23%	59%	36%	15%	30%	15%	
5	State Line - Roxana	Flowgate	0	550	550	0	547	547	0%	25%	25%	0%	25%	25%	
6	Jordan - West Frankfort	Flowgate	560	0	(560)	483	0	(483)	26%	0%	(26%)	22%	0%	(22%)	
7	Burnham - Munster	Flowgate	0	1,002	1,002	0	0	0	0%	46%	46%	0%	0%	0%	
8	Bedington	Transformer	5	563	558	9	449	440	0%	26%	26%	0%	21%	20%	
9	Chicago Ave - Praxair	Flowgate	0	504	504	4	477	473	0%	23%	23%	0%	22%	22%	
10	Easton - Emuni	Line	684	0	(684)	128	0	(128)	32%	0%	(32%)	6%	0%	(6%)	
11	Lenox - Macnew Tap	Line	0	495	495	0	309	309	0%	23%	23%	0%	14%	14%	
12	Dune Acres - Michigan City	Line	0	0	0	801	0	(801)	0%	0%	0%	37%	0%	(37%)	
13	Glendon - Hosensack	Line	504	6	(498)	195	0	(195)	23%	0%	(23%)	9%	0%	(9%)	
14	Pruntytown	Transformer	0	414	414	0	256	256	0%	19%	19%	0%	12%	12%	
15	Burnham - Munster	Line	0	0	0	0	633	633	0%	0%	0%	0%	29%	29%	
16	Chaparral - Carson	Line	584	0	(584)	0	0	0	27%	0%	(27%)	0%	0%	0%	
17	DoeX530	Transformer	518	25	(493)	0	0	0	24%	1%	(23%)	0%	0%	0%	
18	Prest - Tibb	Flowgate	221	40	(181)	284	0	(284)	10%	2%	(8%)	13%	0%	(13%)	
19	Meridian - Twin Branch	Line	279	0	(279)	162	0	(162)	13%	0%	(13%)	8%	0%	(8%)	
20	All Dam - Kittanning	Line	322	45	(277)	151	2	(149)	15%	2%	(13%)	7%	0%	(7%)	
21	Graceton - Manor	Line	260	520	260	77	242	165	12%	24%	12%	4%	11%	8%	
22	Eldred - Sunbury	Line	24	326	302	24	135	111	1%	15%	14%	1%	6%	5%	
23	Chapparal - Carson	Line	0	0	0	390	0	(390)	0%	0%	0%	18%	0%	(18%)	
24	Kokomo - Tipton W	Flowgate	0	232	232	0	156	156	0%	11%	11%	0%	7%	7%	
25	Bedington - Black Oak	Interface	131	186	55	39	322	283	6%	9%	3%	2%	15%	13%	

Top Constraints

The top five constraints by congestion costs contributed $1,268.3 million, or 63.3 percent, of the total PJM congestion costs in the first three months of 2026. The top five constraints were the Bedington Transformer, the Pruntytown Transformer, the Bedington – Black Oak Interface, the Pruntytown Circuit Breaker, and the Conastone – Northwest Line. Table 11-34 and Table 11-35 show the top constraints contributing to congestion costs by facility for the first three months of 2026 and 2025.

The Bedington Transformer was the largest contributor to congestion costs in the first three months of 2026 with $374.7 million and 18.7 percent of total PJM congestion costs. The day-ahead congestion event hours of the Bedington Transformer increased from 5 in the first three months of 2025 to 563 in the first three months of 2026 and the real-time congestion event hours of the Bedington Transformer increased from 9 in the first three months of 2025 to 449 in the first three months of 2026 (Table 11-32).

37 This table is affected by the identified distribution factor error.

The Pruntytown Transformer was the second largest contributor to congestion costs in the first three months of 2026 with $352.3 million and 17.6 percent of the total PJM congestion costs. The day-ahead congestion event hours of the Pruntytown Transformer increased from 0 in the first three months of 2025 to 414 in the first three months of 2026 and the real-time congestion event hours of the Pruntytown Transformer increased from 0 in the first three months of 2025 to 256 in first three months of 2026 (Table 11-32).

The Bedington – Black Oak Interface was the third largest contributor to congestion costs in the first three months of 2026 with $285.6 million and 14.3 percent of total PJM congestion costs. The day-ahead congestion event hours of the Bedington – Black Oak Interface increased from 131 in the first three months of 2025 to 186 in the first three months of 2026 and the real-time congestion event hours of the Bedington – Black Oak Interface increased from 39 in the first three months of 2025 to 322 in the first three months of 2026 (Table 11-32).

The Pruntytown Circuit Breaker was the fourth largest contributor to congestion costs in the first three months of 2026 with $153.4 million and 7.7 percent of the total PJM congestion costs. The day-ahead congestion event hours of the Pruntytown Circuit Breaker increased from 0 in the first three months of 2025 to 150 in the first three months of 2026 and the real-time congestion event hours of the Pruntytown Circuit Breaker increased from 0 in the first three months of 2025 to 180 in the first three months of 2026 (Table 11-32).

The Conastone - Northwest Line was the fifth largest contributor to congestion costs in the first three months of 2026 with $102.4 million and 5.1 percent of the total PJM congestion costs. The day-ahead congestion event hours of the Conastone - Northwest Line decreased from 173 in the first three months of 2025 to 163 in the first three months of 2026 and the real-time congestion event hours of the Conastone - Northwest Line increased from 66 in the first three months of 2025 to 118 in the first three months of 20265 (Table 11-32).

The Pruntytown Circuit Breaker was the largest contributor to balancing congestion costs in the first three months of 2026. The constraint accounted for 12.7 percent of the total balancing congestion costs in the first three months of 2026.

Table 11-34 Top 25 constraints affecting congestion costs: January through March, 2026[38 39]

				CLMP Credits and Charges (Millions)									
				Day-Ahead				Balancing					
No.	Constraint	Type	Location	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs	Percent of Total PJM Congestion Costs
1	Bedington	Transformer	APS	$66.1	($333.2)	($2.1)	$397.2	($3.3)	$21.1	$1.9	($22.5)	$374.7	18.7%
2	Pruntytown	Transformer	APS	$120.8	($245.8)	($2.2)	$364.4	($3.1)	$9.0	($0.1)	($12.2)	$352.3	17.6%
3	Bedington - Black Oak	Interface	500	$116.9	($188.5)	($0.3)	$305.1	($3.6)	$14.5	($1.4)	($19.5)	$285.6	14.3%
4	Pruntytown	Other	APS	$97.8	($88.3)	$2.5	$188.6	($1.2)	$29.0	($5.1)	($35.2)	$153.4	7.7%
5	Conastone - Northwest	Line	BGE	$67.7	($27.4)	($3.7)	$91.4	$4.3	($5.0)	$1.6	$10.9	$102.4	5.1%
6	Burnham - Munster	Flowgate	MISO	$17.6	($61.0)	$10.0	$88.6	$0.0	$0.0	$0.0	$0.0	$88.6	4.4%
7	Eldred - Sunbury	Line	PPL	($18.1)	($98.5)	($0.3)	$80.1	($11.5)	$1.6	($0.6)	($13.7)	$66.4	3.3%
8	AP South	Interface	500	$25.1	($29.8)	$0.3	$55.1	$0.0	$0.0	($0.0)	($0.0)	$55.1	2.8%
9	East Towanda - Hillside	Line	PE	($4.0)	($54.0)	$1.9	$51.9	$11.5	$12.2	($1.9)	($2.6)	$49.3	2.5%
10	Nottingham	Other	PECO	$40.6	($3.5)	$0.4	$44.5	$10.7	$8.7	($1.4)	$0.6	$45.1	2.2%
11	Messick Road - Ridgeley	Line	APS	$1.2	($33.9)	$0.4	$35.4	$2.5	$0.9	($0.4)	$1.1	$36.6	1.8%
12	BCPEP	Interface	PEPCO	$10.0	($27.5)	($4.1)	$33.3	$0.0	$0.0	$0.0	$0.0	$33.3	1.7%
13	West	Interface	500	($19.7)	($53.5)	($2.5)	$31.3	$0.0	$0.0	$0.0	$0.0	$31.3	1.6%
14	Juniata	Transformer	PPL	$4.3	($26.4)	($0.4)	$30.3	$0.0	$0.0	$0.0	$0.0	$30.3	1.5%
15	Burnham - Munster	Line	COMED	$0.0	$0.0	$0.0	$0.0	($13.1)	($2.7)	($19.3)	($29.7)	($29.7)	(1.5%)
16	Graceton - Manor	Line	BGE	$24.7	$1.2	($0.1)	$23.4	$8.4	$2.6	($1.5)	$4.4	$27.7	1.4%
17	Haumesser Road - Steward	Line	COMED	($9.2)	($25.1)	$1.0	$16.9	$2.0	($4.1)	($0.3)	$5.8	$22.7	1.1%
18	Cedar Creek - Silver Run	Line	DPL	($5.0)	($28.8)	$1.4	$25.1	($4.7)	($5.3)	($3.8)	($3.2)	$22.0	1.1%
19	Lincoln - Straban	Line	PE	$18.5	$4.1	($0.2)	$14.3	$0.8	($5.6)	($0.3)	$6.1	$20.4	1.0%
20	Ashburn - Goose Creek	Line	DOM	$7.4	($12.2)	$0.3	$19.9	$0.0	$0.0	$0.0	$0.0	$19.9	1.0%
21	Lenox - Macnew Tap	Line	PE	$1.1	($16.5)	$0.8	$18.3	$2.7	$1.0	($0.6)	$1.0	$19.3	1.0%
22	Kokomo - Tipton W	Flowgate	MISO	($0.3)	($16.4)	$1.9	$18.1	($0.4)	($1.5)	($1.6)	($0.6)	$17.5	0.9%
23	State Line - Roxana	Flowgate	MISO	$3.7	($2.8)	$2.0	$8.4	($5.5)	$9.4	($10.2)	($25.1)	($16.7)	(0.8%)
24	Chicago Ave - Praxair	Flowgate	MISO	$5.1	($14.1)	$4.4	$23.6	($2.6)	$0.7	($5.3)	($8.7)	$14.9	0.7%
25	Cedar Grove - Clifton	Line	PSEG	$3.2	($10.5)	$1.0	$14.8	($0.6)	$0.1	($1.4)	($2.1)	$12.7	0.6%
	Top 25 Total			$575.4	($1,392.4)	$12.4	$1,980.1	($6.8)	$86.7	($51.6)	($145.1)	$1,835.0	91.6%
	All Other Constraints			$72.4	($218.6)	$9.6	$300.6	($28.4)	$68.4	($35.7)	($132.5)	$168.0	8.4%
	Total			$647.8	($1,610.9)	$22.0	$2,280.7	($35.2)	$155.0	($87.4)	($277.6)	$2,003.0	100.0%

38 All flowgates are mapped to MISO as Location if they are flowgates coordinated by both PJM and MISO regardless of the location of the flowgates.
39 This table is affected by the identified distribution factor error.

Table 11-35 Top 25 constraints affecting congestion costs: January through March, 2025[40]

				CLMP Credits and Charges (Millions)									
				Day-Ahead				Balancing					
No.	Constraint	Type	Location	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs	Percent of Total PJM Congestion Costs
1	Lenox - North Meshoppen	Line	PE	$4.8	($88.3)	$2.5	$95.6	$17.1	$21.7	($2.8)	($7.4)	$88.3	17.5%
2	AP South	Interface	500	$28.2	($42.0)	$4.0	$74.2	$0.5	$1.8	($1.9)	($3.3)	$70.9	14.1%
3	Dune Acres - Michigan City	Flowgate	MISO	$5.1	($39.3)	$10.0	$54.5	($0.1)	$0.1	($0.3)	($0.6)	$53.9	10.7%
4	Chaparral - Carson	Line	DOM	$7.0	($41.7)	$2.9	$51.5	$0.0	$0.0	$0.0	$0.0	$51.5	10.2%
5	AEP - DOM	Interface	500	$20.0	($37.9)	$6.0	$63.9	($21.7)	$54.9	($28.8)	($105.3)	($41.4)	(8.2%)
6	Bedington - Black Oak	Interface	500	$12.1	($30.8)	$1.9	$44.7	($0.7)	$1.6	($1.6)	($3.9)	$40.8	8.1%
7	Nottingham	Other	PECO	$22.7	($3.6)	$1.7	$27.9	$5.8	$1.4	($0.6)	$3.8	$31.7	6.3%
8	Meridian - Twin Branch	Line	AEP	$1.0	($29.0)	$2.1	$32.1	($2.2)	($1.4)	($1.9)	($2.6)	$29.4	5.9%
9	Dune Acres - Michigan City	Line	MISO	$0.0	$0.0	$0.0	$0.0	($9.5)	($1.7)	($16.2)	($24.0)	($24.0)	(4.8%)
10	Conastone - Northwest	Line	BGE	$4.5	($10.0)	$0.6	$15.0	$2.8	($9.5)	($4.2)	$8.1	$23.1	4.6%
11	Jordan - West Frankfort	Flowgate	MISO	($2.5)	($17.8)	$1.5	$16.8	$0.7	$0.7	($1.1)	($1.1)	$15.7	3.1%
12	Joshua Falls	Transformer	AEP	$2.2	($10.3)	$1.5	$14.0	$0.0	$0.0	$0.0	$0.0	$14.0	2.8%
13	Monroe - Lallendorf	Flowgate	MISO	($5.2)	$3.0	($2.9)	($11.1)	($0.6)	($1.1)	($0.3)	$0.3	($10.8)	(2.2%)
14	West	Interface	500	($6.7)	($17.1)	($0.6)	$9.9	$0.0	$0.0	$0.0	$0.0	$9.9	2.0%
15	Pleasant View - Ashburn	Line	DOM	$0.0	$0.0	$0.0	$0.0	$2.4	$4.1	($7.4)	($9.1)	($9.1)	(1.8%)
16	Northport - Albion	Flowgate	MISO	($2.0)	($12.8)	$0.7	$11.5	($1.4)	($0.7)	($2.2)	($2.9)	$8.6	1.7%
17	East Towanda - Hillside	Line	PE	($0.1)	($8.2)	$0.1	$8.2	$0.3	$0.0	($0.0)	$0.2	$8.4	1.7%
18	Cloverdale - Jacksons Ferry	Line	AEP	$0.0	$0.0	$0.0	$0.0	($1.0)	$2.6	($4.0)	($7.6)	($7.6)	(1.5%)
19	Graceton - Manor	Line	BGE	$3.6	($3.4)	$0.0	$7.1	$0.5	$0.4	$0.2	$0.3	$7.4	1.5%
20	Williams Grove	Line	PPL	($2.0)	($9.1)	($0.2)	$6.8	$0.0	$0.0	$0.0	$0.0	$6.8	1.4%
21	Chapparal - Carson	Line	DOM	$0.0	$0.0	$0.0	$0.0	($1.1)	$0.5	($4.5)	($6.1)	($6.1)	(1.2%)
22	Haumesser Road - Steward	Line	COMED	($0.8)	($6.6)	$0.2	$6.0	$0.2	$0.0	($0.2)	($0.1)	$5.9	1.2%
23	Glendon - Hosensack	Line	MEC	$8.9	$1.2	($0.0)	$7.7	($2.2)	($0.2)	$0.0	($2.1)	$5.7	1.1%
24	Capitol Hill - Chemical	Line	AEP	($1.4)	($6.5)	$0.1	$5.2	$0.0	$0.0	$0.0	$0.0	$5.2	1.0%
25	University Park - Olive	Flowgate	MISO	$0.9	($3.0)	$1.0	$4.9	$0.0	$0.0	$0.0	$0.0	$4.9	1.0%
	Top 25 Total			$100.3	($413.2)	$33.1	$546.6	($10.3)	$75.4	($77.7)	($163.3)	$383.2	76.2%
	All Other Constraints			$65.0	($83.4)	$8.6	$156.9	($16.4)	$3.7	($16.8)	($36.9)	$120.0	23.8%
	Total			$165.3	($496.6)	$41.7	$703.5	($26.7)	$79.1	($94.5)	($200.2)	$503.3	100.0%

40 All flowgates are mapped to MISO as Location if they are flowgates coordinated by both PJM and MISO regardless of the location of the flowgates.

Figure 11-4 shows the total hourly congestion costs of the top five constraints in the first three months of 2026. The Bedington Transformer was the top constraint.

Figure 11-4 Top five constraints affecting total congestion costs: January through March, 2026[41]

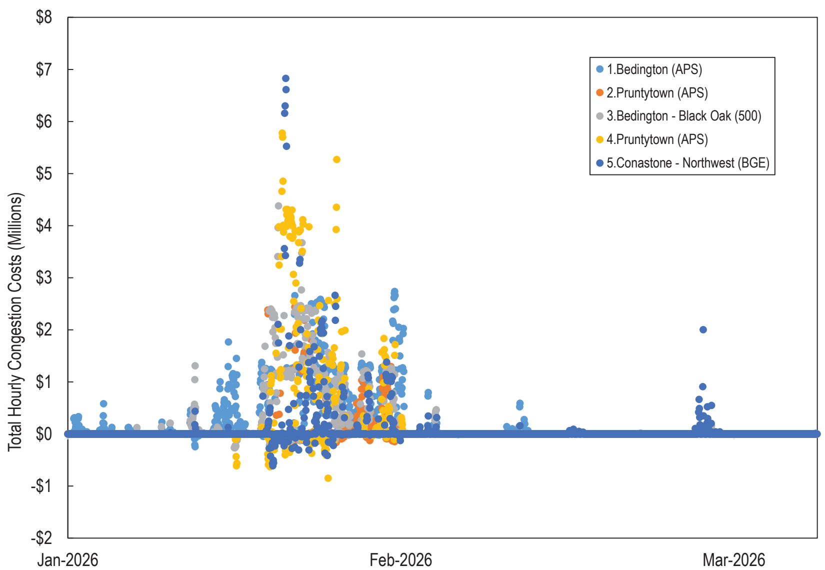
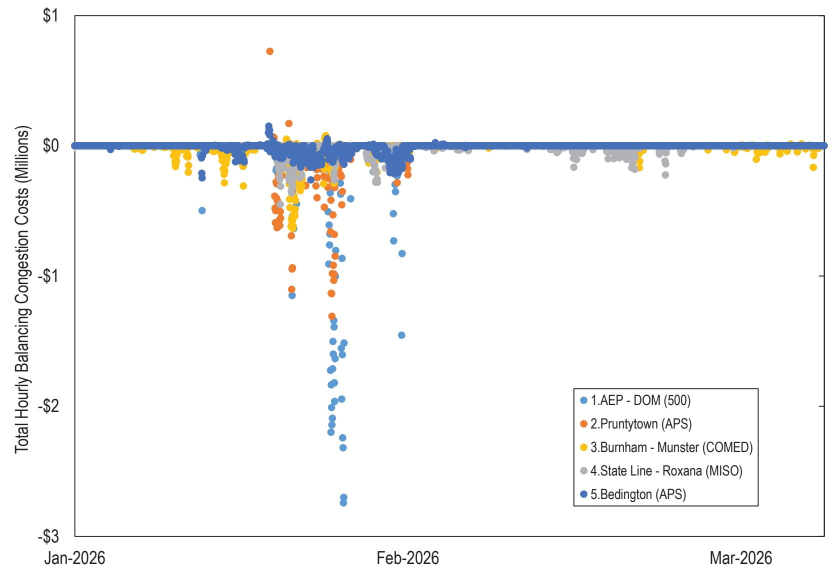


Figure 11-5 shows the total hourly balancing congestion costs of the top five constraints in the first three months of 2026.

Figure 11-5 Top five constraints affecting balancing congestion costs: January through March, 2026[42]



41 This figure is affected by the identified distribution factor error.

42 This figure is affected by the identified distribution factor error.

Figure 11-6 shows the total hourly day-ahead congestion costs of the top five constraints in the first three months of 2026.

Figure 11-6 Top five constraints affecting day-ahead congestion costs: January through March, 2026[43]

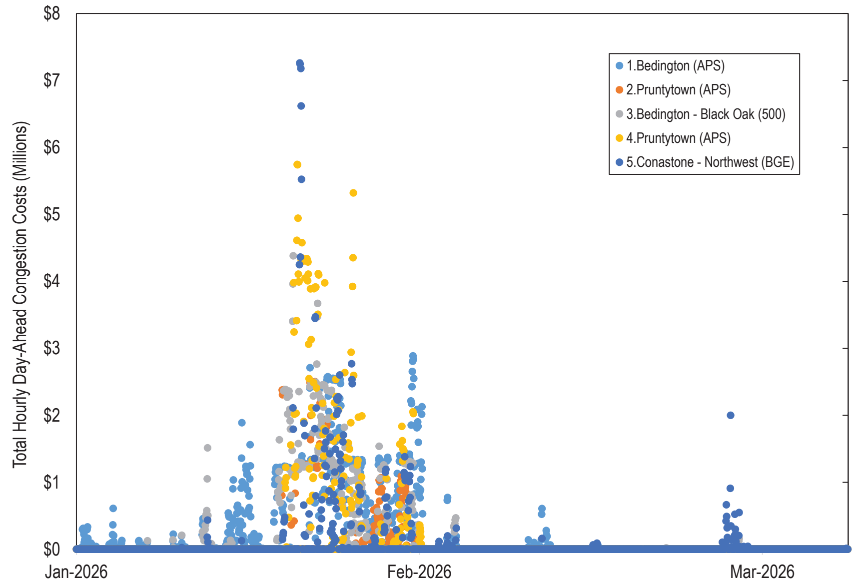
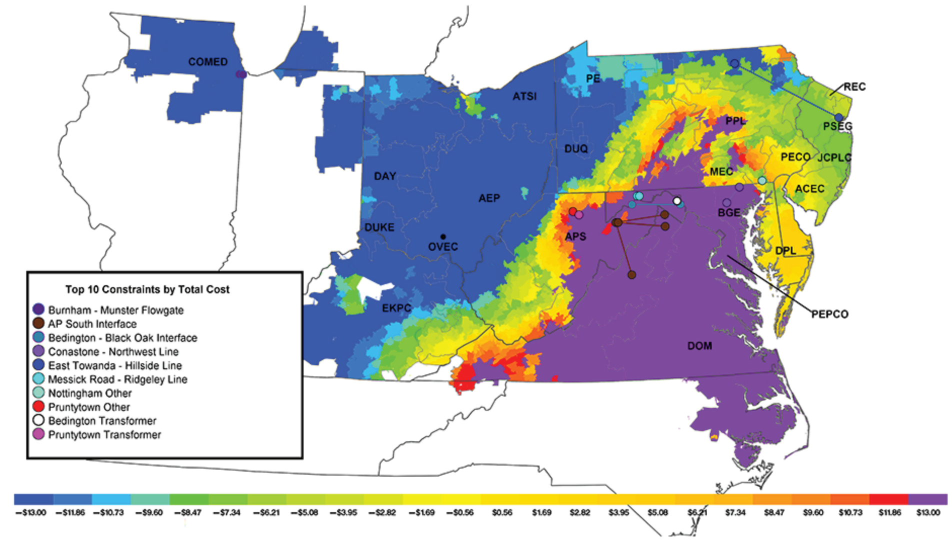


Figure 11-7 shows the locations of the top 10 constraints by total congestion costs on a contour map of the real-time, load-weighted average CLMP in the first three months of 2026.

Figure 11-7 Location of the top 10 constraints by total congestion costs: January through March, 2026



43 This figure is affected by the identified distribution factor error.

Figure 11-8 shows the locations of the top 10 constraints by balancing congestion costs on a contour map of the real-time load-weighted average CLMP in the first three months of 2026.

Figure 11-8 Location of top 10 constraints by balancing congestion costs: January through March, 2026

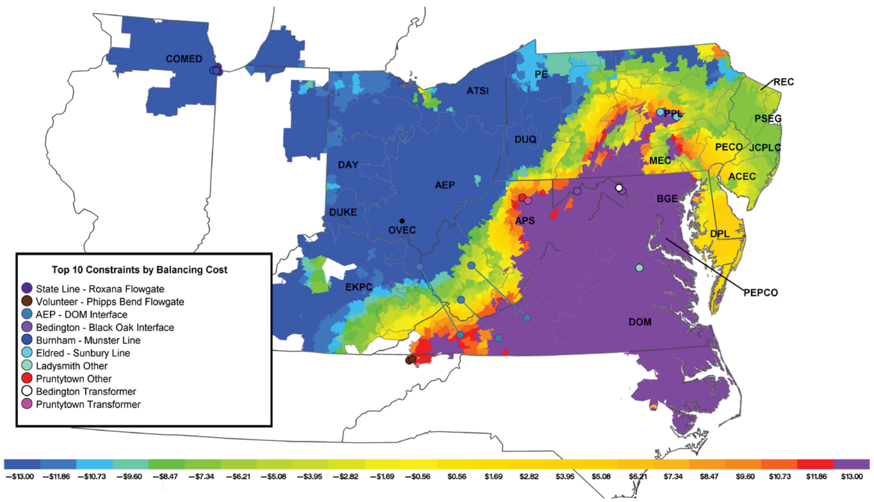
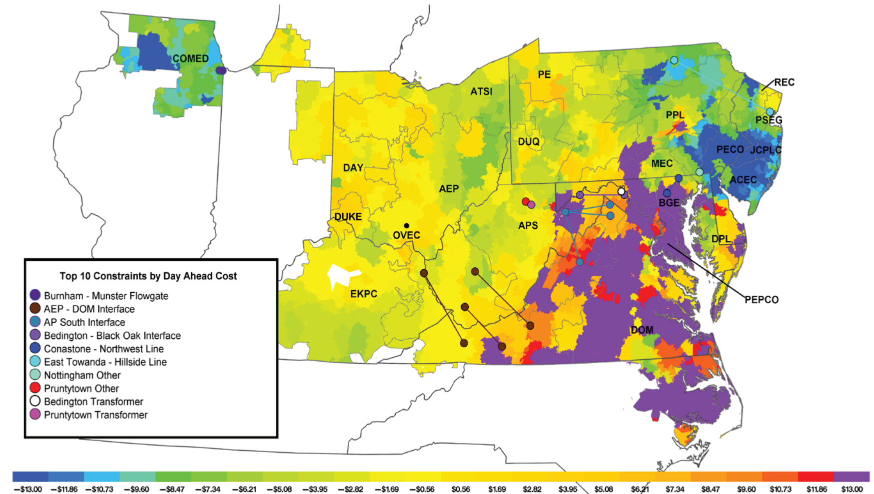


Figure 11-9 shows the locations of the top 10 constraints by day-ahead congestion costs on a contour map of the day-ahead load-weighted average CLMP in the first three months of 2026.

Figure 11-9 Location of top 10 constraints by day-ahead congestion costs: January through March, 2026



Comparing Figure 11-8 (Location of the top 10 constraints by balancing congestion costs) and

Figure 11-9 (Location of the top 10 constraints by day-ahead congestion costs) shows the significant differences between the day-ahead and real-time markets.

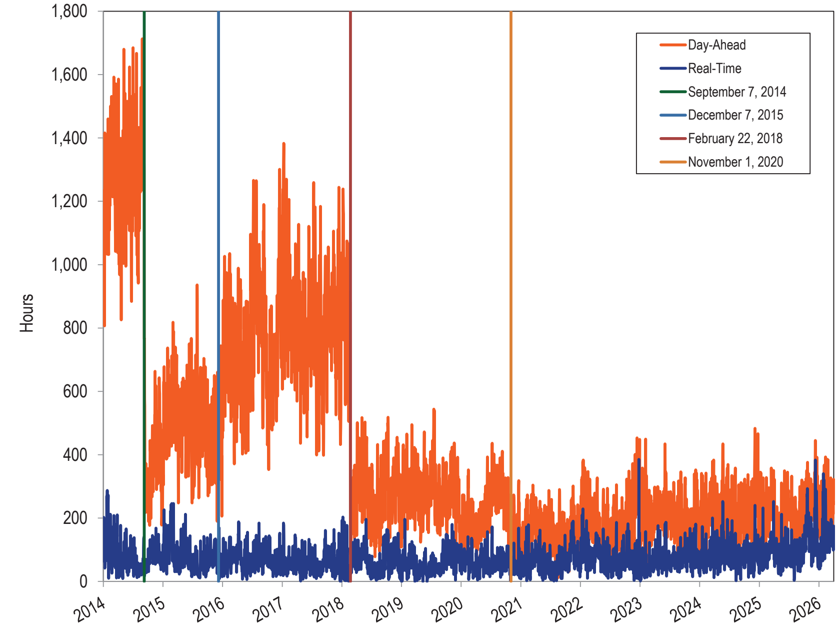
Congestion Event Summary: Impact of Changes in UTC Volumes

UTCs have a significant impact on congestion events in the day-ahead market and, as a result, contribute to differences between day-ahead and real-time congestion events. The greater the volume of UTCs, the greater the number of congestion events in the day-ahead market and the greater the differences between the day-ahead and real-time congestion events.[44]

In the first three months of 2026, the average hourly cleared UTC MW decreased by 25.8 percent, compared to the first three months of 2025. Day-ahead congestion event hours decreased by 1.2 percent from 20,824 congestion event hours in the first three months of 2025 to 20,569 congestion event hours in the first three months of 2026 (Table 11-26).

Figure 11-10 shows the daily day-ahead and real-time congestion event hours for January 2014 through March 2026.

Figure 11-10 Daily congestion event hours: January 2014 through March 2026



Marginal Losses

Marginal Loss Accounting

Marginal losses occur in the day-ahead and real-time energy markets. PJM calculates marginal loss costs for each PJM member. The loss cost is based on the applicable day-ahead and real-time marginal loss component of LMP (MLMP). Losses are the difference between what load (withdrawals) pay for energy and what generation (injections) are paid for energy, due to transmission line losses.

Losses increase with distance between sources and sinks and the amount of power moved. Total loss collected (loss surplus) increases with load, holding

44 A series of FERC orders has affected UTC activity which has in turn affected congestion events in the day-ahead market. See Appendix F: Congestion and Marginal Losses.

distance and resistance constant. Every incremental increase in load has to be met with a slightly larger increment of generation. The result is that the total energy losses increase as load increases.

Ignoring interchange, total generation MWh must be greater than total load MWh in any hour in order to provide for losses. Total marginal loss costs, analogous to total congestion costs, are equal to the net of the withdrawal loss charges minus injection loss credits, plus explicit loss charges, incurred in both the day-ahead energy market and the balancing energy market.

Total marginal loss costs can be more accurately thought of as net marginal loss costs. Total marginal loss costs equal implicit marginal loss charges plus explicit marginal loss charges plus net inadvertent loss charges. Implicit marginal loss charges equal withdrawal loss charges minus injection loss credits. Net explicit marginal loss costs are the net marginal loss costs associated with point to point energy transactions. Net inadvertent loss charges are the losses associated with the hourly difference between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area.[45] Unlike the other categories of marginal loss accounting, inadvertent loss charges are costs not directly attributable to specific participants. Inadvertent loss charges are assigned to participants based on real-time load (excluding losses) ratio share.[46] Each of these categories of marginal loss costs is comprised of day-ahead and balancing marginal loss costs.

The accounting definitions can be misleading. Load pays losses. Losses are the difference between what load pays for energy and what generation is paid for energy due to losses. Generation does not pay losses. Some generation receives a price lower than SMP and some generation receives a price greater than SMP due to the MLMP but that does not mean that generation is paying or being paid losses. It means that generation is being paid an LMP that is higher or lower than the system load-weighted, average LMP due to losses on the system.

While PJM accounting focuses on MLMPs, the individual MLMP values at any bus are irrelevant to the calculation of total losses. Total losses are the net surplus revenue that remains after all sources and sinks are credited or charged their LMPs. Changing the components of LMP by electing a different reference bus does not change the LMPs or the difference between LMPs for a given market solution or losses, it merely changes the components of the LMP.

The MLMP component of LMP is the marginal cost of energy, due to losses associated with serving load at the bus. The MLMP at the load-weighted reference bus is the marginal cost of energy at the load-weighted reference bus (holding the proportion of load at every bus constant). Due to losses, MLMP is non zero at the load reference bus. The LMP at the load reference bus is the system marginal price of energy (SMP) plus the marginal cost of energy due to losses at the reference bus.

Load-weighted LMP components are calculated relative to a load-weighted, average LMP. LMPs at specific load buses will reflect the fact that marginal generators must produce more (or less) energy due to losses to serve that bus than is needed to serve the load-weighted reference bus. The LMP at any bus is a function of the SMP, losses and congestion. Relative to the system marginal price (SMP) at the load-weighted reference bus, the loss factor can be either positive or negative.

At the load-weighted reference bus, the LMP includes no congestion component, but does include a loss component. The load-weighted average MLMP across all load buses, calculated relative to that reference bus is positive. The LMPs at the load buses are a function of marginal generation bus LMPs determined through the least cost security constrained economic dispatch which accounts for transmission constraints and marginal losses.

Other than the effect on the optimal dispatch point, LMP at the marginal generator bus, and therefore the payment to the generator, is not affected by marginal losses. By paying for losses based on marginal instead of average losses at the load bus, a revenue over collection occurs.

The residual difference between total marginal loss related load charges (day-ahead and balancing) and marginal loss related generation credits (day-ahead and balancing) after virtual bids have settled their marginal loss related credits and charges for their day-ahead and balancing positions is total loss.

45 PJM Operating Agreement Schedule 1 §3.7.
46 *Id.*

That is, losses are the difference between what withdrawals (load) are paying for energy and what injections (generation) are being paid for energy due to losses, after virtual bids marginal loss related charges and credits are settled at the end of the market day. Load is the source of the net loss surplus after generation is paid and virtuals are settled at the end of the market day. Load pays losses. Generation does not pay losses.

Day-ahead marginal loss costs are based on day-ahead MWh priced at the marginal loss price component of LMP. Balancing marginal loss costs are based on the load or generation deviations between the day-ahead and real-time energy markets priced at the marginal loss price component of LMP in the real-time energy market. If a participant has real-time generation or load that is greater than its day-ahead generation or load then the deviation will be positive. If there is a positive load deviation at a bus where the real-time LMP has a positive marginal loss component, positive balancing marginal loss costs will result. Similarly, if there is a positive load deviation at a bus where real-time LMP has a negative marginal loss component, negative balancing marginal loss costs will result. If a participant has real-time generation or load that is less than its day-ahead generation or load then the deviation will be negative. If there is a negative load deviation at a bus where real-time LMP has a positive marginal loss component, negative balancing marginal loss costs will result. Similarly, if there is a negative load deviation at a bus where real-time LMP has a negative marginal loss component, positive balancing marginal loss costs will result.

The total marginal loss surplus is the remaining loss amount from collection of marginal losses, after accounting for total system energy costs and net residual market adjustments. The marginal loss surplus is allocated to PJM market participants based on real-time load plus export ratio share as marginal loss credits.[47]

Day-Ahead Implicit Load MLMP Charges

- **Day-Ahead Implicit Load MLMP Charges.** Day-ahead implicit load MLMP charges are calculated for all cleared demand, decrement bids and day-ahead energy market sale transactions. Day-ahead implicit load MLMP charges are calculated using MW and the load bus MLMP, the decrement bid MLMP or the MLMP at the source of the sale transaction.
- **Day-Ahead Implicit Generation MLMP Credits.** Day-ahead implicit generation MLMP credits are calculated for all cleared generation and increment offers and day-ahead energy market purchase transactions. Day-ahead implicit generation MLMP credits are calculated using MW and the generator bus MLMP, the increment offer MLMP or the MLMP at the sink of the purchase transaction.
- **Balancing Implicit Load MLMP Charges.** Balancing implicit load MLMP charges are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing implicit load MLMP charges are calculated using MW deviations and the real-time MLMP for each bus where a deviation exists.
- **Balancing Implicit Generation MLMP Credits.** Balancing implicit Generation MLMP credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing implicit Generation MLMP credits are calculated using MW deviations and the real-time MLMP for each bus where a deviation exists.
- **Explicit Loss Charges.** Explicit loss charges are the net loss costs associated with point to point energy transactions, including UTCs. These costs equal the product of the transacted MW and MLMP differences between sources (origins) and sinks (destinations) in the day-ahead energy market. Balancing energy market explicit loss costs equal the product of the differences between the real-time and day-ahead transacted MW and the differences between the real-time MLMP at the transactions' sources and sinks.
- **Inadvertent Loss Charges.** Inadvertent loss charges are the net loss charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour. This inadvertent interchange of energy may be positive or negative,

47 See PJM. "Manual 28: Operating Agreement Accounting," Rev. 98 (December 17, 2024).

where positive interchange typically results in a charge while negative interchange typically results in a credit. Inadvertent loss charges are common costs, not directly attributable to specific participants, which are distributed on a load plus export ratio basis.[48]

Total Marginal Loss Cost

Total marginal loss is the difference between what withdrawals (load) pay for energy and what injections (generation) are paid for energy due to losses, after generation is paid and virtuals' marginal loss related charges and credits are settled. Load pays losses.

The total marginal loss cost in PJM for the first three months of 2026 was $860.0 million, which was comprised of implicit withdrawal MLMP charges of $36.4 million minus implicit injection MLMP credits of -$829.7 million plus explicit loss charges of -$6.0 million plus inadvertent loss charges of $0.0 million (Table 11-37).

Monthly marginal loss costs in the first three months of 2026 ranged from $94.3 million in March to $517.4 million in January. Total marginal loss surplus increased in the first three months of 2026 by $165.2 million or 105.1 percent from $157.3 million in the first three months of 2025 to $322.5 million in the first three months of 2026.

Table 11-36 shows the total marginal loss component costs and the total PJM billing for January through March, 2008 through 2026.

48 PJM Operating Agreement Schedule 1 §3.7.

Table 11-36 Total loss component costs (Dollars (Millions)): January through March, 2008 through 2026[49 50]

(Jan - Mar)	Loss Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$607	NA	$7,718	7.9%
2009	$454	(25.2%)	$7,515	6.0%
2010	$417	(8.2%)	$8,415	5.0%
2011	$410	(1.7%)	$9,584	4.3%
2012	$234	(42.8%)	$6,938	3.4%
2013	$278	18.5%	$7,762	3.6%
2014	$776	179.5%	$21,070	3.7%
2015	$425	(45.2%)	$14,040	3.0%
2016	$170	(60.0%)	$9,500	1.8%
2017	$172	0.9%	$9,710	1.8%
2018	$339	97.9%	$14,520	2.3%
2019	$204	(39.9%)	$11,600	1.8%
2020	$109	(46.8%)	$8,750	1.2%
2021	$210	93.2%	$11,260	1.9%
2022	$393	87.5%	$18,080	2.2%
2023	$201	(48.8%)	$11,890	1.7%
2024	$217	7.8%	$12,350	1.8%
2025	$429	97.7%	$18,690	2.3%
2026	$860	100.5%	$36,350	2.4%

Total marginal loss is the difference between what withdrawals (load) pay for energy and what injections (generation) are paid for energy due to losses, after generation is paid and virtuals' marginal loss related charges and credits are settled. Load pays losses. Figure 11-11 shows the contour map of the day-ahead, load-weighted average MLMP in the first three months of 2026.

49 The loss costs include net inadvertent charges.
50 In Table **11-36**, the MMU uses Total PJM Billing values provided by PJM. For 2019 and after, the MMU has modified the Total PJM Billing calculation to better reflect historical PJM total billing through the PJM settlement process.

Figure 11-11 Contour map of the day-ahead, load-weighted average MLMP: January through March, 2026

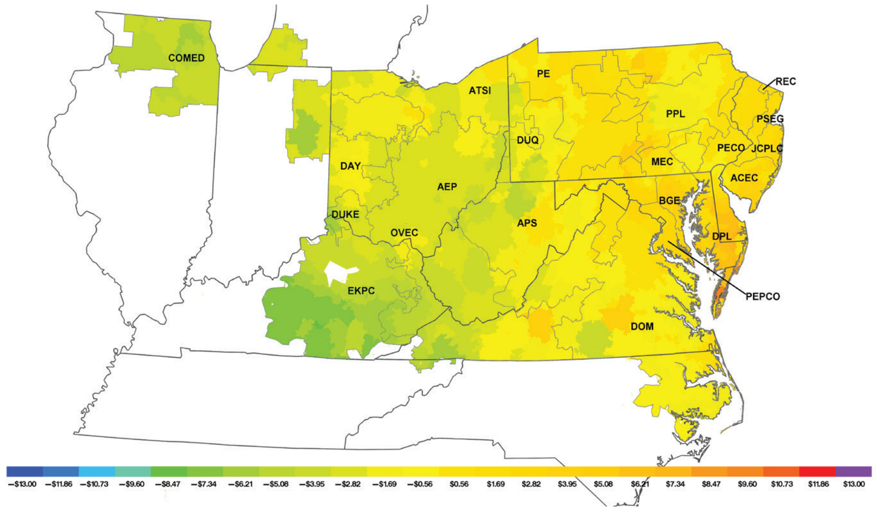
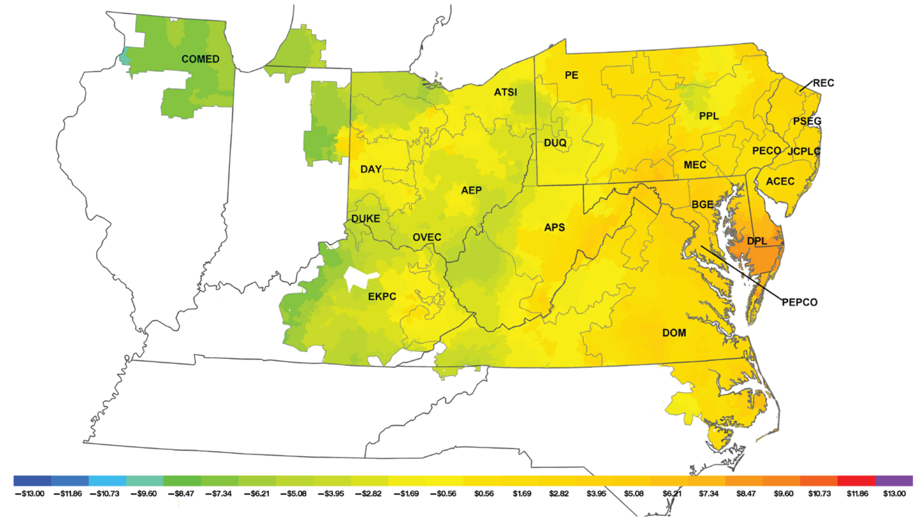


Figure 11-12 Contour map of the real-time, load-weighted average MLMP: January through March, 2026



Total marginal loss is the difference between what withdrawals (load) pay for energy and what injections (generation) are paid for energy due to losses, after generation is paid and virtuals' marginal loss related charges and credits are settled. Load pays losses. Figure 11-12 shows the contour map of the real-time, load-weighted average MLMP in the first three months of 2026.

Table 11-37 shows PJM total marginal loss costs by accounting category for January through March, 2008 through 2026. Table 11-38 shows PJM total marginal loss costs by accounting category by market for the first three months of 2008 through 2026.

Table 11-37 Total marginal loss costs by accounting category (Dollars (Millions)): January through March, 2008 through 2026

	Marginal Loss Costs (Millions)				
(Jan - Mar)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Inadvertent Charges	Total
2008	($52.1)	($634.0)	$25.1	$0.0	$606.9
2009	($21.3)	($460.6)	$14.7	$0.0	$454.0
2010	($3.8)	($414.1)	$6.3	($0.0)	$416.6
2011	($26.5)	($421.2)	$14.9	$0.0	$409.6
2012	($11.2)	($252.1)	($6.6)	$0.0	$234.3
2013	$8.0	($277.8)	($8.2)	($0.0)	$277.6
2014	($15.1)	($813.7)	($22.8)	$0.0	$775.9
2015	($4.0)	($434.0)	($4.9)	$0.0	$425.1
2016	($8.0)	($184.4)	($6.3)	$0.0	$170.1
2017	($13.0)	($196.2)	($11.6)	($0.0)	$171.5
2018	($13.2)	($356.7)	($4.0)	$0.0	$339.4
2019	($13.7)	($220.9)	($3.2)	$0.0	$203.9
2020	($9.8)	($122.1)	($3.8)	($0.0)	$108.5
2021	$2.1	($208.8)	($1.2)	$0.0	$209.7
2022	$85.9	($315.3)	($8.1)	($0.0)	$393.1
2023	$8.1	($196.3)	($3.2)	($0.0)	$201.2
2024	$11.5	($208.1)	($2.6)	$0.0	$217.0
2025	$50.6	($382.1)	($3.9)	($0.0)	$428.9
2026	$36.4	($829.7)	($6.0)	$0.0	$860.0

Table 11-38 Total marginal loss costs by market (Dollars (Millions)): January through March, 2008 through 2026

	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
(Jan - Mar)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
2008	($17.1)	($603.7)	$31.3	$617.9	($35.0)	($30.2)	($6.2)	($11.0)	$0.0	$606.9
2009	($23.3)	($457.6)	$30.9	$465.2	$2.1	($3.0)	($16.3)	($11.2)	$0.0	$454.0
2010	($8.5)	($413.5)	$12.8	$417.8	$4.7	($0.6)	($6.5)	($1.2)	($0.0)	$416.6
2011	($37.1)	($430.1)	$26.0	$419.1	$10.6	$8.9	($11.1)	($9.5)	$0.0	$409.6
2012	($16.7)	($256.8)	$8.0	$248.1	$5.6	$4.7	($14.6)	($13.8)	$0.0	$234.3
2013	($0.1)	($288.2)	$8.1	$296.2	$8.1	$10.4	($16.3)	($18.6)	($0.0)	$277.6
2014	($48.6)	($847.4)	$32.3	$831.1	$33.5	$33.7	($55.1)	($55.3)	$0.0	$775.9
2015	($17.4)	($441.6)	$7.8	$432.0	$13.5	$7.6	($12.8)	($6.9)	$0.0	$425.1
2016	($10.7)	($186.3)	$7.6	$183.3	$2.7	$1.9	($14.0)	($13.2)	$0.0	$170.1
2017	($15.1)	($197.5)	$17.5	$199.9	$2.1	$1.3	($29.1)	($28.3)	($0.0)	$171.5
2018	($15.3)	($352.2)	$10.1	$347.0	$2.1	($4.5)	($14.1)	($7.5)	$0.0	$339.4
2019	($13.8)	($219.3)	$14.5	$219.9	$0.1	($1.6)	($17.7)	($16.1)	$0.0	$203.9
2020	($10.0)	($122.6)	$9.5	$122.0	$0.2	$0.4	($13.2)	($13.4)	($0.0)	$108.5
2021	$2.7	($208.8)	$9.0	$220.5	($0.6)	($0.0)	($10.2)	($10.8)	$0.0	$209.7
2022	$95.3	($314.8)	$15.3	$425.4	($9.4)	($0.5)	($23.4)	($32.3)	($0.0)	$393.1
2023	$10.1	($194.3)	$18.4	$222.8	($2.0)	($2.0)	($21.6)	($21.6)	($0.0)	$201.2
2024	$13.2	($205.9)	$17.2	$236.2	($1.7)	($2.2)	($19.7)	($19.3)	$0.0	$217.0
2025	$54.2	($377.0)	$18.5	$449.7	($3.6)	($5.1)	($22.3)	($20.8)	($0.0)	$428.9
2026	$44.9	($820.0)	$14.1	$879.0	($8.6)	($9.7)	($20.2)	($19.0)	$0.0	$860.0

Table 11-39 and Table 11-40 show PJM accounting based total loss costs for each transaction type in the first three months of 2026 and 2025.

Virtual transaction loss costs, when positive, measure the total loss costs to virtual transactions and when negative, measure the total loss credits to virtual transactions. In the first three months of 2026, DECs were paid $3.1 million in MLMP credits in the day-ahead market, paid $2.0 million in MLMP in the balancing energy market and were paid $1.1 million in total MLMP charges. In the first three months of 2026, INCs paid $33.1 million in MLMP charges in the day-ahead market, were paid $31.5 million in MLMP credits in the balancing energy market and were paid $1.5 million in total MLMP credits. In the first three months of 2026, up to congestion paid $15.7 million in MLMP charges in the day-ahead market, were paid $18.9 million in MLMP credits in the balancing energy market and received $3.2 million in total MLMP credits.

Table 11-39 Total loss costs by transaction type (Dollars (Millions)): January through March, 2026

	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	($3.1)	$0.0	$0.0	($3.1)	$2.0	$0.0	$0.0	$2.0	$0.0	($1.1)
Demand	($1.1)	$0.0	$0.0	($1.1)	$8.1	$0.0	$0.0	$8.1	$0.0	$7.0
Demand Response	$0.7	$0.0	$0.0	$0.7	($0.6)	$0.0	$0.0	($0.6)	$0.0	$0.1
Explicit Congestion and Loss Only	$0.0	$0.0	($1.5)	($1.5)	$0.0	$0.0	($0.1)	($0.1)	$0.0	($1.5)
Export	($8.9)	$0.0	($0.1)	($9.0)	($14.5)	$0.0	($0.9)	($15.4)	$0.0	($24.4)
Generation	$0.0	($837.4)	$0.0	$837.4	$0.0	($8.6)	$0.0	$8.6	$0.0	$846.0
Import	$0.0	($7.0)	$0.0	$7.0	$0.0	($29.1)	$0.0	$29.1	$0.0	$36.0
INC	$0.0	($33.1)	$0.0	$33.1	$0.0	$31.5	$0.0	($31.5)	$0.0	$1.5
Internal Bilateral	$57.4	$57.5	$0.1	($0.0)	($3.6)	($3.6)	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$15.7	$15.7	$0.0	$0.0	($18.9)	($18.9)	$0.0	($3.2)
Wheel In	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	($0.3)	($0.3)	$0.0	($0.3)
Total	$44.9	($820.0)	$14.1	$879.0	($8.6)	($9.7)	($20.2)	($19.0)	$0.0	$860.0

Table 11-40 Total loss costs by transaction type (Dollars (Millions)): January through March, 2025

	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	($0.9)	$0.0	$0.0	($0.9)	$2.2	$0.0	$0.0	$2.2	$0.0	$1.3
Demand	$34.1	$0.0	$0.0	$34.1	$4.6	$0.0	$0.0	$4.6	$0.0	$38.7
Demand Response	$0.3	$0.0	$0.0	$0.3	($0.2)	$0.0	$0.0	($0.2)	$0.0	$0.0
Explicit Congestion and Loss Only	$0.0	$0.0	($1.0)	($1.0)	$0.0	$0.0	($0.1)	($0.1)	$0.0	($1.1)
Export	($5.7)	$0.0	($0.1)	($5.8)	($8.2)	$0.0	($0.3)	($8.4)	$0.0	($14.2)
Generation	$0.0	($387.8)	$0.0	$387.8	$0.0	($11.5)	$0.0	$11.5	$0.0	$399.3
Import	$0.0	($0.9)	$0.0	$0.9	$0.0	($9.8)	$0.0	$9.8	$0.0	$10.7
INC	$0.0	($15.1)	$0.0	$15.1	$0.0	$18.1	$0.0	($18.1)	$0.0	($3.0)
Internal Bilateral	$26.5	$26.8	$0.3	($0.0)	($2.0)	($1.9)	$0.0	($0.1)	$0.0	($0.1)
Up to Congestion	$0.0	$0.0	$19.3	$19.3	$0.0	$0.0	($21.9)	($21.9)	$0.0	($2.6)
Wheel In	$0.0	$0.0	($0.1)	($0.1)	$0.0	$0.0	($0.1)	($0.1)	$0.0	($0.2)
Total	$54.2	($377.0)	$18.5	$449.7	($3.6)	($5.1)	($22.3)	($20.8)	$0.0	$428.9

Table 11-41 compares MLMP credits and charges for each transaction type between the dispatch run and pricing run in the first three months of 2026. Total MLMP charges to generation decreased by $47.2 million, and total MLMP charges to demand increased by $0.7 million from the dispatch run to the pricing run. The total MLMP charges to DECs increased by $0.4 million, the total MLMP credits to INCs decreased by $3.1 million and the total CLMP credits to UTCs decreased by $1.9 million from the dispatch run to the pricing run.

Table 11-41 Total loss costs by dispatch and pricing run (Dollars (Millions)): January through March, 2026

	Marginal Loss Costs (Millions)								
	Dispatch Run			Pricing Run			Difference		
Transaction Type	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total
DEC	($3.3)	$1.9	($1.4)	($3.1)	$2.0	($1.1)	$0.2	$0.2	$0.4
Demand	($1.1)	$7.4	$6.3	($1.1)	$8.1	$7.0	($0.0)	$0.7	$0.7
Demand Response	$0.7	($0.6)	$0.2	$0.7	($0.6)	$0.1	($0.0)	($0.1)	($0.1)
Explicit Congestion and Loss Only	($1.5)	($0.1)	($1.5)	($1.5)	($0.1)	($1.5)	$0.0	($0.0)	($0.0)
Export	($10.1)	($14.2)	($24.3)	($9.0)	($15.4)	($24.4)	$1.1	($1.2)	($0.2)
Generation	$885.2	$8.1	$893.3	$837.4	$8.6	$846.0	($47.7)	$0.5	($47.2)
Import	$7.0	$26.9	$34.0	$7.0	$29.1	$36.0	($0.1)	$2.1	$2.0
INC	$33.9	($29.3)	$4.6	$33.1	($31.5)	$1.5	($0.8)	($2.2)	($3.1)
Internal Bilateral	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	$0.0	($0.0)	($0.0)
Up to Congestion	$16.1	($17.4)	($1.3)	$15.7	($18.9)	($3.2)	($0.5)	($1.4)	($1.9)
Wheel In	($0.0)	($0.3)	($0.3)	($0.0)	($0.3)	($0.3)	($0.0)	($0.0)	($0.0)
Total	$926.9	($17.5)	$909.4	$879.0	($19.0)	$860.0	($47.9)	($1.5)	($49.4)

Monthly Marginal Loss Costs

Table 11-42 shows a monthly summary of marginal loss costs by market type for January 2025 through March 2026.

Table 11-42 Monthly marginal loss costs (Millions): January 2025 through March 2026

	Marginal Loss Costs (Millions)							
	2025				2026			
	Day-Ahead	Balancing	Inadvertent Charges	Total	Day-Ahead	Balancing	Inadvertent Charges	Total
Jan	$233.1	($10.4)	($0.0)	$222.8	$521.8	($4.4)	$0.0	$517.4
Feb	$121.0	($5.1)	($0.0)	$115.9	$258.2	($9.9)	$0.0	$248.3
Mar	$95.6	($5.4)	($0.0)	$90.2	$99.0	($4.7)	$0.0	$94.3
Apr	$81.1	($2.4)	($0.0)	$78.7				
May	$79.3	($4.4)	($0.0)	$74.9				
Jun	$143.9	($10.2)	($0.0)	$133.7				
Jul	$204.2	($7.6)	($0.0)	$196.6				
Aug	$99.4	($3.6)	$0.0	$95.9				
Sep	$91.9	($5.0)	($0.0)	$86.8				
Oct	$114.9	($3.4)	($0.0)	$111.5				
Nov	$120.5	($4.4)	($0.0)	$116.1				
Dec	$187.0	($6.8)	($0.0)	$180.2				
Total	$1,571.9	($68.6)	($0.0)	$1,503.3	$879.0	($19.0)	$0.0	$860.0

Figure 11-13 shows PJM monthly marginal loss costs for January 2008 through March 2026.

Figure 11-13 Monthly marginal loss cost (Dollars (Millions)): January 2008 through March 2026

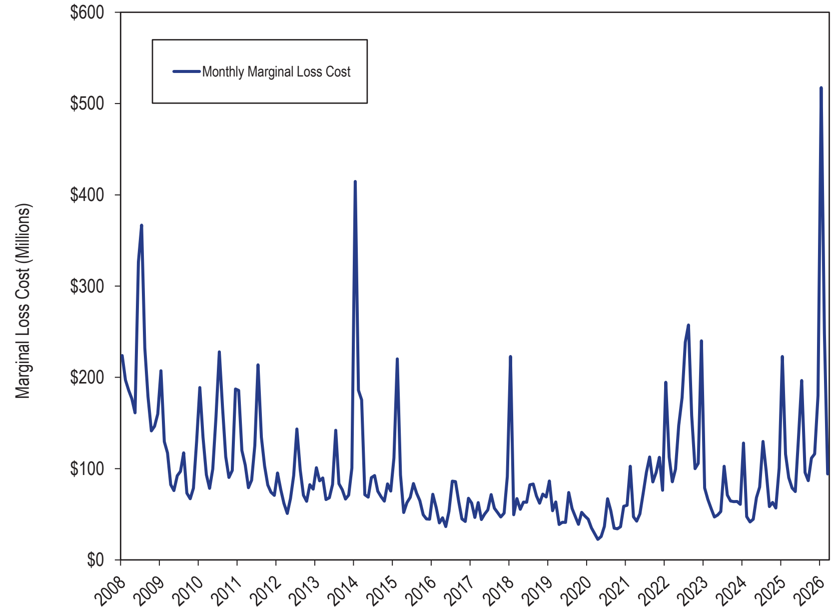


Table 11-43 shows the monthly total loss charges for each virtual transaction type for January 2025 through March 2026. In the first three months of 2026, 116.3 percent of the total credits to virtuals went to UTCs, compared to 60.1 percent in the first three months of 2025.

Table 11-43 Monthly loss charges by virtual transaction type (Dollars (Millions)): January 2025 through March 2026

		Marginal Loss Charges (Millions)									
		DEC			INC			Up to Congestion			
Year		Day-Ahead	Balancing	Total	Day-Aheatd	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
2025	Jan	($0.1)	$1.1	$1.0	$6.3	($7.6)	($1.3)	$9.4	($9.9)	($0.5)	($0.8)
	Feb	($0.4)	$0.4	($0.0)	$3.6	($4.8)	($1.1)	$5.5	($7.0)	($1.6)	($2.7)
	Mar	($0.4)	$0.8	$0.3	$5.1	($5.7)	($0.5)	$4.5	($4.9)	($0.5)	($0.7)
	Apr	($0.8)	$0.8	($0.0)	$4.5	($4.5)	($0.0)	$3.3	($3.6)	($0.3)	($0.3)
	May	$0.2	$0.1	$0.3	$3.4	($3.5)	($0.1)	$4.4	($3.9)	$0.4	$0.6
	Jun	($0.4)	$1.2	$0.8	$2.7	($3.7)	($1.0)	$7.5	($9.3)	($1.7)	($1.9)
	Jul	($2.2)	$2.7	$0.5	$3.7	($3.7)	($0.0)	$6.2	($7.2)	($1.0)	($0.5)
	Aug	($1.5)	$1.6	$0.2	$2.1	($2.0)	$0.1	$3.2	($3.9)	($0.7)	($0.5)
	Sep	($1.0)	$1.2	$0.3	$2.5	($2.5)	$0.0	$4.5	($5.3)	($0.7)	($0.5)
	Oct	($1.5)	$1.7	$0.2	$5.9	($5.9)	($0.1)	$4.5	($5.0)	($0.5)	($0.3)
	Nov	($1.6)	$1.6	$0.1	$7.2	($6.4)	$0.8	$7.4	($7.3)	$0.1	$1.0
	Dec	$1.0	($0.9)	$0.0	$6.7	($6.7)	$0.1	$7.9	($8.7)	($0.8)	($0.7)
	Total	($8.7)	$12.4	$3.7	$53.8	($57.0)	($3.2)	$68.3	($76.1)	($7.8)	($7.3)
2026	Jan	($4.1)	$2.7	($1.4)	$16.9	($13.1)	$3.8	$6.6	($8.3)	($1.7)	$0.7
	Feb	$1.3	($1.1)	$0.2	$12.2	($13.8)	($1.6)	$4.9	($5.5)	($0.5)	($2.0)
	Mar	($0.2)	$0.4	$0.2	$3.9	($4.6)	($0.7)	$4.1	($5.1)	($1.0)	($1.5)
	Total	($3.1)	$2.0	($1.1)	$33.1	($31.5)	$1.5	$15.7	($18.9)	($3.2)	($2.8)

Marginal Loss Costs and Loss Credits

Total marginal loss surplus is calculated by adding the total system energy costs (which are negative), the total marginal loss costs (which are positive) and net residual market adjustments (which can be net positive or negative). The total system energy costs are equal to the net implicit energy charges (implicit withdrawal charges minus implicit injection credits) plus net inadvertent energy charges. Total marginal loss costs are equal to the net implicit marginal loss charges (implicit load MLMP charges less implicit generation MLMP credits) plus net explicit loss charges plus net inadvertent loss charges.

Ignoring interchange, total generation MWh must be greater than total load MWh in any hour in order to provide for losses. Since the hourly integrated energy component of LMP is the same for every bus within every hour, the net energy bill is negative (ignoring net interchange), with more injection credits than withdrawal charges in every hour. The greater the level of load the greater the difference between energy charges collected from load (SMP x load MW) and credited to generation (SMP x generation MW). Total system energy costs plus total marginal loss costs plus net residual market adjustments equal marginal loss credits which are distributed to the PJM market participants according to the ratio of their real-time load plus their real-time exports to total PJM real-time load plus real-time exports as marginal loss credits. The net residual market adjustment is calculated as known day-ahead error value minus day-ahead loss MW congestion value and minus balancing loss MW congestion value.

Table 11-44 shows the total system energy costs, the total marginal loss costs collected, the net residual market adjustments and total marginal loss surplus redistributed for January through March, 2008 through 2026. The total marginal loss surplus increased by $165.2 million or 105.1 percent in the first three months of 2026 from the first three months of 2025.

Table 11-44 Marginal loss surplus (Dollars (Millions)): January through March, 2008 through 2026[51]

	Marginal Loss Surplus (Millions)					
	System Energy Cost	Marginal Loss Costs	Net Residual Market Adjustments			Total Marginal Loss Surplus
(Jan - Mar)			Known Day-Ahead Error	Day-Ahead Loss MW Congestion	Balancing Loss MW Congestion	
2008	($288.2)	$606.9	$0.0	$0.0	$0.0	$318.7
2009	($218.3)	$454.0	($0.0)	($0.4)	($0.1)	$236.2
2010	($207.6)	$416.6	$0.0	($0.9)	($0.0)	$209.9
2011	($209.9)	$409.6	$0.0	$0.0	($0.0)	$199.7
2012	($136.4)	$234.3	($0.0)	($0.5)	$0.0	$98.3
2013	($177.9)	$277.6	$0.1	$0.3	$0.0	$99.4
2014	($515.3)	$775.9	$0.0	$3.1	$0.2	$257.2
2015	($271.7)	$425.1	($0.5)	$2.9	($0.0)	$150.0
2016	($113.6)	$170.1	$0.0	$0.8	($0.0)	$55.7
2017	($122.1)	$171.5	$0.0	$0.2	($0.0)	$49.2
2018	($226.6)	$339.4	($0.0)	$1.2	($0.0)	$111.6
2019	($136.3)	$203.9	$0.0	$0.7	($0.0)	$66.9
2020	($75.3)	$108.5	($0.0)	($0.0)	($0.0)	$33.2
2021	($131.5)	$209.7	($0.0)	$1.0	($0.0)	$77.2
2022	($260.8)	$393.1	($0.0)	$3.8	($0.0)	$128.5
2023	($135.6)	$201.2	$0.0	($0.0)	($0.0)	$65.7
2024	($145.6)	$217.0	$0.0	$0.1	($0.1)	$71.4
2025	($270.9)	$428.9	($0.0)	$0.7	$0.0	$157.3
2026	($538.0)	$860.0	$0.0	($0.5)	$0.0	$322.5

System Energy Costs

Energy Accounting

The system energy component of LMP is the system reference bus LMP, also called the system marginal price (SMP). The system energy cost is based on the day-ahead and real-time energy components of LMP. Total system energy costs, analogous to total congestion costs or total loss costs, are equal to the withdrawal energy charges minus injection energy credits, in both the day-ahead energy market and the balancing energy market, plus net inadvertent energy charges. Total system energy costs can be more accurately thought of as net system energy costs. Due to line losses associated with moving energy from generation to load, more energy is injected by generation than is withdrawn by load. Total system energy charges are negative because there are, due to losses, more generation MW being paid SMP (energy component of price) than load MW paying SMP (the energy component of price).

Total System Energy Costs

The total system energy cost for the first three months of 2026 was -$538.0 million, which was comprised of implicit withdrawal energy charges of $29,954.4 million, implicit injection energy credits of $30,501.6 million, explicit energy charges of $0.0 million and inadvertent energy charges of $9.2 million. The monthly system energy costs for the first three month of 2026 ranged from -$323.8 million in January to -$59.6 million in March.

Table 11-45 shows total system energy costs and total PJM billing, for January through March, 2008 through 2026.

Table 11-45 Total system energy costs (Dollars (Millions)): January through March, 2008 through 2026[52] [53]

(Jan - Mar)	System Energy Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	($288)	NA	$7,718	(3.7%)
2009	($218)	(24.2%)	$7,515	(2.9%)
2010	($208)	(4.9%)	$8,415	(2.5%)
2011	($210)	1.1%	$9,584	(2.2%)
2012	($136)	(35.0%)	$6,938	(2.0%)
2013	($178)	30.4%	$7,762	(2.3%)
2014	($515)	189.7%	$21,070	(2.4%)
2015	($272)	(47.3%)	$14,040	(1.9%)
2016	($114)	(58.2%)	$9,500	(1.2%)
2017	($122)	7.5%	$9,710	(1.3%)
2018	($227)	85.6%	$14,520	(1.6%)
2019	($136)	(39.8%)	$11,600	(1.2%)
2020	($75)	(44.8%)	$8,750	(0.9%)
2021	($132)	74.6%	$11,260	(1.2%)
2022	($261)	98.3%	$18,080	(1.4%)
2023	($136)	(48.0%)	$11,890	(1.1%)
2024	($146)	7.4%	$12,350	(1.2%)
2025	($271)	86.1%	$18,690	(1.4%)
2026	($538)	98.6%	$36,350	(1.5%)

System energy costs for January through March, 2008 through 2026 are shown in Table 11-46 and Table 11-47. Table 11-46 shows PJM system energy

51 The net residual market adjustments included in the table are comprised of the known day-ahead error value minus the sum of the day-ahead loss MW congestion value, balancing loss MW congestion value and measurement error caused by missing data.

52 The system energy costs include net inadvertent charges.

53 In Table 11-45, the MMU uses Total PJM Billing values provided by PJM. For 2019 and after, the MMU has modified the Total PJM Billing calculation to better reflect historical PJM total billing through the PJM settlement process.

costs by accounting category and Table 11-47 shows PJM system energy costs by market category.

Table 11-46 Total system energy costs by accounting category (Dollars (Millions)): January through March, 2008 through 2026

	System Energy Costs (Millions)				
(Jan - Mar)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Inadvertent Charges	Total
2008	$28,435.7	$28,723.9	$0.0	$0.0	($288.2)
2009	$14,058.4	$14,277.4	$0.0	$0.7	($218.3)
2010	$13,424.4	$13,629.0	$0.0	($3.0)	($207.6)
2011	$11,943.9	$12,160.7	$0.0	$6.9	($209.9)
2012	$8,485.4	$8,628.7	$0.0	$6.8	($136.4)
2013	$10,357.2	$10,535.1	$0.0	($0.0)	($177.9)
2014	$28,506.2	$29,014.7	$0.0	($6.9)	($515.3)
2015	$15,702.1	$15,976.4	$0.0	$2.6	($271.7)
2016	$7,764.7	$7,879.3	$0.0	$1.0	($113.6)
2017	$8,789.3	$8,910.2	$0.0	($1.3)	($122.1)
2018	$13,910.8	$14,142.2	$0.0	$4.7	($226.6)
2019	$8,856.0	$8,993.5	$0.0	$1.2	($136.3)
2020	$5,541.1	$5,616.0	$0.0	($0.4)	($75.3)
2021	$8,663.3	$8,795.5	$0.0	$0.6	($131.5)
2022	$15,137.8	$15,398.2	$0.0	($0.4)	($260.8)
2023	$8,785.6	$8,920.1	$0.0	($1.1)	($135.6)
2024	$9,545.8	$9,692.0	$0.0	$0.6	($145.6)
2025	$16,405.9	$16,674.4	$0.0	($2.4)	($270.9)
2026	$29,954.4	$30,501.6	$0.0	$9.2	($538.0)

Table 11-47 Total system energy costs by market (Dollars (Millions)): January through March, 2008 through 2026

	System Energy Costs (Millions)								
	Day-Ahead				Balancing				
(Jan - Mar)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges
2008	$20,253.8	$20,579.6	$0.0	($325.8)	$8,182.0	$8,144.3	$0.0	$37.6	$0.0
2009	$14,129.6	$14,375.6	$0.0	($246.0)	($71.2)	($98.2)	$0.0	$27.0	$0.7
2010	$13,408.9	$13,619.2	$0.0	($210.2)	$15.5	$9.8	$0.0	$5.6	($3.0)
2011	$12,055.5	$12,259.3	$0.0	($203.9)	($111.6)	($98.6)	$0.0	($12.9)	$6.9
2012	$8,534.4	$8,649.0	$0.0	($114.6)	($49.0)	($20.4)	$0.0	($28.6)	$6.8
2013	$10,387.2	$10,580.9	$0.0	($193.7)	($29.9)	($45.8)	$0.0	$15.9	($0.0)
2014	$28,412.1	$29,082.9	$0.0	($670.9)	$94.2	($68.3)	$0.0	$162.4	($6.9)
2015	$15,764.8	$16,077.5	$0.0	($312.6)	($62.7)	($101.1)	$0.0	$38.4	$2.6
2016	$7,847.5	$7,997.9	$0.0	($150.4)	($82.8)	($118.6)	$0.0	$35.8	$1.0
2017	$8,927.5	$9,111.3	$0.0	($183.8)	($138.1)	($201.1)	$0.0	$63.0	($1.3)
2018	$13,877.2	$14,123.7	$0.0	($246.5)	$33.6	$18.5	$0.0	$15.1	$4.7
2019	$8,965.4	$9,131.8	$0.0	($166.4)	($109.4)	($138.4)	$0.0	$28.9	$1.2
2020	$5,612.2	$5,708.5	$0.0	($96.3)	($71.1)	($92.5)	$0.0	$21.4	($0.4)
2021	$8,749.4	$8,901.4	$0.0	($152.0)	($86.0)	($105.9)	$0.0	$19.8	$0.6
2022	$15,372.2	$15,651.2	$0.0	($279.1)	($234.4)	($253.0)	$0.0	$18.7	($0.4)
2023	$8,872.5	$9,054.2	$0.0	($181.7)	($86.9)	($134.1)	$0.0	$47.2	($1.1)
2024	$9,647.5	$9,823.1	$0.0	($175.6)	($101.7)	($131.1)	$0.0	$29.5	$0.6
2025	$16,160.2	$16,467.6	$0.0	($307.5)	$245.7	$206.7	$0.0	$39.0	($2.4)
2026	$29,931.1	$30,516.2	$0.0	($585.2)	$23.3	($14.7)	$0.0	$38.0	$9.2

Grand Total
($288.2)
($218.3)
($207.6)
($209.9)
($136.4)
($177.9)
($515.3)
($271.7)
($113.6)
($122.1)
($226.6)
($136.3)
($75.3)
($131.5)
($260.8)
($135.6)
($145.6)
($270.9)
($538.0)

Table **11-48** and Table 11-49 show the total system energy costs for each transaction type in the first three months of 2026 and 2025. In the first three months of 2026, generation was paid $21,635.4 million and demand paid $20,621.9 million in net energy payment. In the first three months of 2025, generation was paid $11,850.0 million and demand paid $11,099.4 million in net energy payment.

Table 11-48 Total system energy costs by transaction type (Dollars (Millions)): January through March, 2026

	System Energy Costs (Millions)								
	Day-Ahead				Balancing				
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total
DEC	$848.9	$0.0	$0.0	$848.9	($824.2)	$0.0	$0.0	($824.2)	$24.7
Demand	$20,269.7	$0.0	$0.0	$20,269.7	$352.1	$0.0	$0.0	$352.1	$20,621.9
Demand Response	($37.5)	$0.0	$0.0	($37.5)	$31.3	$0.0	$0.0	$31.3	($6.2)
Export	$715.7	$0.0	$0.0	$715.7	$383.0	$0.0	$0.0	$383.0	$1,098.8
Generation	$0.0	$21,417.3	$0.0	($21,417.3)	$0.0	$218.1	$0.0	($218.1)	($21,635.4)
Import	$0.0	$102.0	$0.0	($102.0)	$0.0	$520.2	$0.0	($520.2)	($622.2)
INC	$0.0	$862.7	$0.0	($862.7)	$0.0	($834.0)	$0.0	$834.0	($28.7)
Internal Bilateral	$8,132.4	$8,132.4	$0.0	$0.0	$70.9	$70.9	$0.0	($0.0)	($0.0)
Wheel In	$0.0	$1.8	$0.0	($1.8)	$0.0	$10.1	$0.0	($10.1)	($11.9)
Wheel Out	$1.8	$0.0	$0.0	$1.8	$10.1	$0.0	$0.0	$10.1	$11.9
Total	$29,931.1	$30,516.2	$0.0	($585.2)	$23.3	($14.7)	$0.0	$38.0	($547.2)

Table 11-49 Total system energy costs by transaction type by (Dollars (Millions)): January through March, 2025

	System Energy Costs (Millions)								
	Day-Ahead				Balancing				
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total
DEC	$559.0	$0.0	$0.0	$559.0	($561.2)	$0.0	$0.0	($561.2)	($2.3)
Demand	$10,900.3	$0.0	$0.0	$10,900.3	$199.1	$0.0	$0.0	$199.1	$11,099.4
Demand Response	($14.0)	$0.0	$0.0	($14.0)	$12.6	$0.0	$0.0	$12.6	($1.4)
Export	$517.0	$0.0	$0.0	$517.0	$219.1	$0.0	$0.0	$219.1	$736.2
Generation	$0.0	$11,602.5	$0.0	($11,602.5)	$0.0	$247.5	$0.0	($247.5)	($11,850.0)
Import	$0.0	$24.1	$0.0	($24.1)	$0.0	$225.4	$0.0	($225.4)	($249.5)
INC	$0.0	$643.2	$0.0	($643.2)	$0.0	($642.3)	$0.0	$642.3	($0.9)
Internal Bilateral	$4,196.5	$4,196.5	$0.0	($0.0)	$368.8	$368.8	$0.0	$0.0	$0.0
Wheel In	$0.0	$1.4	$0.0	($1.4)	$0.0	$7.4	$0.0	($7.4)	($8.7)
Wheel Out	$1.4	$0.0	$0.0	$1.4	$7.4	$0.0	$0.0	$7.4	$8.7
Total	$16,160.2	$16,467.6	$0.0	($307.5)	$245.7	$206.7	$0.0	$39.0	($268.5)

Table 11-50 compares the total system energy costs for each transaction type between the dispatch run and the pricing run in the first three months of 2026. The system energy charges to demand decreased $1,149.2 million, and the energy credits to generation increased $1,206.6 million from the dispatch run to the pricing run. The energy charges to DECs decreased $70.2 million, the energy credits to INCs increased $78.0 million from the dispatch run to the pricing run.

Table 11-50 Total system energy costs by dispatch and pricing run (Dollars (Millions)): January through March, 2026

	System Energy Costs (Millions)								
	Dispatch Run			Pricing Run			Difference		
Transaction Type	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total
DEC	$861.9	($767.0)	$95.0	$848.9	($824.2)	$24.7	($13.0)	($57.2)	($70.2)
Demand	$21,444.3	$326.8	$21,771.1	$20,269.7	$352.1	$20,621.9	($1,174.5)	$25.3	($1,149.2)
Demand Response	($40.2)	$28.5	($11.7)	($37.5)	$31.3	($6.2)	$2.7	$2.8	$5.5
Export	$743.2	$353.9	$1,097.1	$715.7	$383.0	$1,098.8	($27.5)	$29.2	$1.7
Generation	($22,641.8)	($200.2)	($22,842.0)	($21,417.3)	($218.1)	($21,635.4)	$1,224.5	($17.9)	$1,206.6
Import	($103.6)	($481.9)	($585.5)	($102.0)	($520.2)	($622.2)	$1.6	($38.2)	($36.6)
INC	($883.6)	$776.9	($106.7)	($862.7)	$834.0	($28.7)	$20.9	$57.1	$78.0
Internal Bilateral	($0.0)	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	$0.0	($0.0)	($0.0)
Wheel In	($1.8)	($9.5)	($11.3)	($1.8)	($10.1)	($11.9)	($0.0)	($0.6)	($0.6)
Wheel Out	$1.8	$9.5	$11.3	$1.8	$10.1	$11.9	$0.0	$0.6	$0.6
Total	($619.8)	$37.0	($582.8)	($585.2)	$38.0	($547.2)	$34.7	$1.0	$35.6

Monthly System Energy Costs

Table 11-51 shows a monthly summary of system energy costs by market type for January 2025 through March 2026. Total balancing system energy costs in the first three months of 2026 increased in every month compared to the first three months of 2025 except for January. Monthly total system energy costs in the first three months of 2026 ranged from -$323.8 million in January to -$59.6 million in March.

Table 11-51 Monthly system energy costs (Dollars (Millions)): January 2025 through March 2026

	System Energy Costs (Millions)							
	2025				2026			
	Day-Ahead	Balancing	Inadvertent Charges	Total	Day-Ahead	Balancing	Inadvertent Charges	Total
Jan	($153.9)	$16.7	($0.6)	($137.8)	($336.8)	$9.0	$4.0	($323.8)
Feb	($85.3)	$9.8	($0.8)	($76.2)	($173.6)	$16.0	$3.0	($154.6)
Mar	($68.3)	$12.4	($1.0)	($56.9)	($74.8)	$12.9	$2.2	($59.6)
Apr	($55.5)	$7.0	($1.2)	($49.7)				
May	($56.4)	$11.5	($1.5)	($46.4)				
Jun	($95.5)	$10.0	($0.4)	($86.0)				
Jul	($133.5)	$9.7	($0.4)	($124.2)				
Aug	($65.6)	$6.9	$0.7	($58.0)				
Sep	($64.4)	$12.4	($1.0)	($53.0)				
Oct	($77.3)	$12.8	($1.5)	($65.9)				
Nov	($83.6)	$13.5	($0.8)	($70.9)				
Dec	($128.1)	$17.0	($1.1)	($112.1)				
Total	($1,067.5)	$139.9	($9.5)	($937.2)	($585.2)	$38.0	$9.2	($538.0)

Figure 11-14 shows PJM monthly system energy costs for January 2008 through March 2026. Ignoring interchange, total generation MWh must be greater than total load MWh in any hour in order to provide for losses. Since the hourly integrated energy component of LMP (SMP) is the same for every bus in the market in every hour, the net energy bill is always negative (ignoring net interchange): (SMP x withdrawals + SMP x injections) < 0. Assuming power balance is maintained in the presence of losses, the greater the level of load the greater the difference between energy charges collected from load (SMP x load MW) and credited to generation (SMP x generation MW). With higher load levels, there are generally higher SMPs and more negative total energy charges.

Figure 11-14 Monthly system energy costs (Millions): January 2008 through March 2026

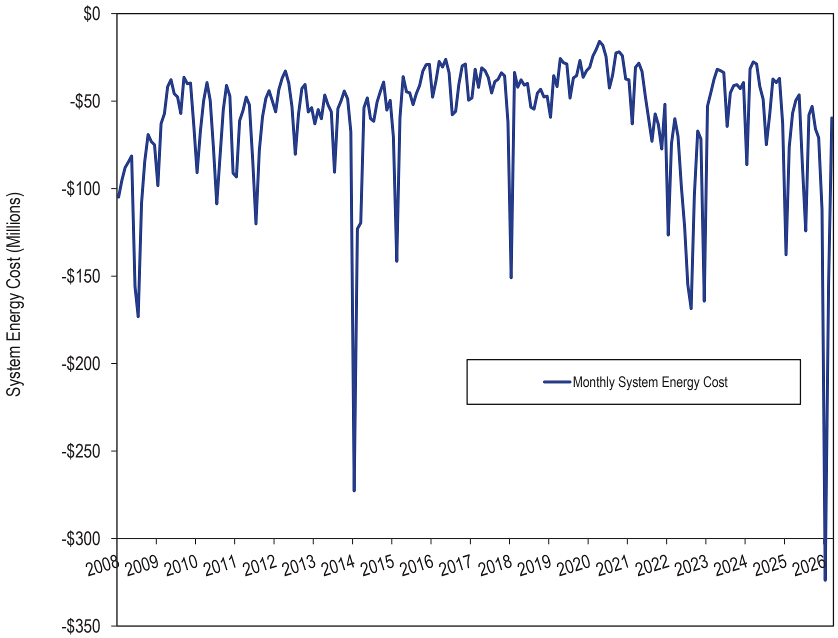


Table 11-52 shows the monthly total system energy costs for each virtual transaction type in the first three months of 2026 and 2025. In the first three months of 2026, DECs paid $848.9 million in energy charges compared to $559.0 million in the first three months of 2025 in the day-ahead market, were paid $824.2 million in energy credits compared to $561.2 million in the first three months of 2025 in the balancing energy market and paid $24.7 million in total energy charges compared to $2.3 million in total energy credits in the first three months of 2025. In the first three months of 2026, INCs were paid $862.7 million in energy credits compared to $643.2 million in the first three months of 2025 in the day-ahead market, paid $834.0 million in energy charges compared to $642.3 million in the first three months of 2025 in the balancing market and were paid $28.7 million in total energy credits compared to $0.9 million in total energy charges in the first three months of 2025. The system energy costs are zero for UTCs because the system energy costs for UTCs equal the difference in the energy component between source and sink and the energy component is the same at all buses.

Table 11-52 Monthly energy charges by virtual transaction type (Dollars (Millions)): January 2025 through March 2026

		Energy Charges (Millions)						
		DEC			INC			
Year		Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
2025	Jan	$232.3	($228.2)	$4.1	($269.2)	$261.9	($7.3)	($3.2)
	Feb	$167.5	($168.2)	($0.7)	($192.3)	$191.8	($0.5)	($1.2)
	Mar	$159.2	($164.8)	($5.6)	($181.7)	$188.6	$6.9	$1.3
	Apr	$144.2	($146.2)	($2.0)	($193.9)	$196.4	$2.5	$0.5
	May	$143.6	($138.3)	$5.3	($141.2)	$139.1	($2.1)	$3.2
	Jun	$225.4	($273.0)	($47.6)	($148.9)	$182.0	$33.1	($14.5)
	Jul	$310.6	($281.0)	$29.7	($225.8)	$200.9	($24.9)	$4.7
	Aug	$192.0	($193.1)	($1.1)	($134.2)	$134.5	$0.3	($0.8)
	Sep	$205.1	($212.9)	($7.8)	($141.0)	$148.1	$7.1	($0.7)
	Oct	$200.4	($201.6)	($1.1)	($225.8)	$225.7	($0.1)	($1.2)
	Nov	$176.9	($167.7)	$9.2	($240.6)	$226.8	($13.8)	($4.6)
	Dec	$241.4	($226.9)	$14.5	($249.1)	$233.9	($15.2)	($0.7)
	Total	$2,398.6	($2,401.9)	($3.3)	($2,343.6)	$2,329.7	($13.9)	($17.3)
2026	Jan	$400.4	($337.0)	$63.3	($405.1)	$329.8	($75.3)	($12.0)
	Feb	$266.6	($288.3)	($21.7)	($297.4)	$329.5	$32.0	$10.4
	Mar	$181.9	($198.9)	($17.0)	($160.2)	$174.7	$14.6	($2.4)
	Total	$848.9	($824.2)	$24.7	($862.7)	$834.0	($28.7)	($4.0)

Generation and Transmission Planning Overview[1]

Generation Interconnection Planning

Existing Generation Mix

- As of March 31, 2026, PJM had a total installed capacity of 203,028.6 MW, of which 38,366.4 MW (18.9 percent) are coal fired steam units, 57,047.7 MW (28.1 percent) are combined cycle units and 33,452.6 MW (16.5 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 203,028.6 MW of installed capacity, 75,558.5 MW (37.2 percent) are from units older than 40 years, of which 30,814.3 MW (40.8 percent) are coal fired steam units, 255.0 MW (0.3 percent) are combined cycle units and 25,550.6 MW (33.8 percent) are nuclear units.

Generation Retirements[2]

- As of March 31, 2026, there were 64,202.9 MW of generation that have been, or are planned to be, retired between 2011 and 2031, of which 46,526.8 MW (72.5 percent) are coal fired steam units.
- In the first three months of 2026, 2.0 MW of generation retired. The largest generator that retired in the first three months of 2026 was the 2.0 MW Beckjord Storage Unit 1 battery unit located in the DUKE Zone. Of the 2.0 MW of generation that retired in the first three months of 2026, 2.0 MW (100.0 percent) were located in the DUKE Zone.
- As of March 31, 2026, there were 8,455.3 MW of generation that have requested retirement after March 31, 2026, of which 2,671.9 MW (31.6 percent) are located in the COMED Zone. Of the generation requesting retirement in the COMED Zone, 1,527.9 MW (57.2 percent) are combustion turbine natural gas units.

1 Totals presented in this section include corrections to historical data and may not match totals presented in previous reports.
2 See PJM. Planning. "Generator Deactivations," (Accessed on March 31, 2026) <https://www.pjm.com/planning/service-requests/gen-deactivations>.

Generation Queue

New Service Requests Serial Process[3]

- On November 29, 2022, the Commission issued an order accepting PJM's tariff revisions to improve the queue process.[4] The new queue process includes modifications to implement a cluster/cycle based processing method to replace the first in/first out serial processing method.[5] 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.
- There were 8,190 generation request projects submitted in the new service request serial process queue from 1997 until the implementation of the new cycle process on July 10, 2023. As a result of the transition to the new services cycle process, 312 projects (40,650.1 MW) were moved to transition cycle 1 (TC1). There were 1,347 projects eligible to resubmit for evaluation in transition cycle 2 (TC2). Of those 1,347 eligible projects, 550 projects (49,168.4 MW) resubmitted and are now being evaluated in TC2. Of the 1,347 eligible projects, 797 projects (53,155.5 MW) did not resubmit, and were withdrawn from the queue. There were 1,070 projects initially entered into the AH2 queue and beyond. Those 1,070 projects (70,729.8 MW) are now considered invalid and have been removed from the queue. As a result of the transition to the cycle process, the 8,190 projects in the serial process queue have been reduced to 5,461 projects. Projects that will be evaluated in TC1 and TC2, and those projects no longer eligible to be evaluated in the serial process have been removed from the new service requests serial process metrics. New service requests cycle process metrics are reported separately from the serial process metrics.

3 See PJM. Planning. "Serial Service Request Status," (Accessed on March 31, 2026) <https://www.pjm.com/planning/service-requests/serial-service-request-status>.
4 See 181 FERC ¶ 61,162 (2022).
5 See "Interconnection Process Reform," presented at the April 27, 2022 Members Committee meeting. <https://www.pjm.com/-/media/committees-groups/committees/mc/2022/20220427/20220427-item-01a-1-interconnection-process-reform-presentation.ashx>.

- As of March 31, 2026, a total of 40,220.7 MW, on an energy basis, were in generation request serial service queues in the status of active, under construction or suspended.[6] Based on historical completion rates, 21,232.8 MW (52.8 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 5,312.5 MW, on an energy basis, of thermal projects (including combined cycle, CT natural gas, CT oil and coal fired steam projects) in the serial queue, 3,775.7 MW (71.1 percent) are expected to go in service based on historical completion rates as of March 31, 2026.
- Of the 3,090.4 MW, on an energy basis, of battery projects in the serial queue, only 834.5 MW (27.0 percent) are expected to go in service based on historical completion rates as of March 31, 2026.
- Of the 31,773.8 MW, on an energy basis, of renewable projects in the serial queue, 16,600.0 MW (52.2 percent) are expected to go in service based on historical completion rates as of March 31, 2026.
- Of the 5,140.6 MW, on a capacity basis that requested CIRs, of thermal projects (including combined cycle, CT natural gas. CT oil and coal fired steam projects) requested in the generation serial queues in the status of active, under construction or suspended, 3,587.9 MW (69.8 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 2028/2029 Base Residual Auction,[7] the 5,140.6 MW of capacity requests currently under construction, suspended or active in the serial queue would be reduced to 2,713.4 MW of capacity (52.8 percent of the total requested capacity).[8]
- Of the 2,082.6 MW, on a capacity basis that requested CIRs, of battery projects requested in the generation serial queues in the status of active, under construction or suspended, 234.1 MW (11.2 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 2028/2029 Base Residual Auction, the 2,082.6 MW of capacity requests currently under construction, suspended or active in the serial queue would be reduced to 138.1 MW of capacity (6.6 percent of the total requested capacity).
- Of the 16,418.1 MW, on a capacity basis that requested CIRs, of renewable projects requested in the serial generation queues in the status of active, under construction or suspended, 8,575.2 MW (52.2 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 2028/2029 Base Residual Auction, the 16,518.1 MW of capacity requests currently under construction, suspended or active in the serial queue would be reduced to 986.5 MW of capacity (6.0 percent of the total requested capacity).
- As of March 31, 2026, 23,685.3 MW of capacity requests (requested CIRs) were in the generation serial queues in the status of active, under construction or suspended. Based on historical completion rates, 12,419.2 MW (52.4 percent) are expected to go into service. Based on historical completion rates and the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction, the 23,685.3 MW of capacity requests currently under construction, suspended or active in the serial queue would be reduced to 3,859.2 MW of capacity (16.3 percent of the total requested capacity).
- As of March 31, 2026, 5,461 projects, representing 609,227.4 MW, have entered the serial queue process since its inception. Of those, 1,284 projects, representing 95,178.1 MW (15.6 percent of the MW), went into service. Of the projects that entered the serial queue process, 3,769 projects, representing 473,828.6 MW (77.8 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.

6 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.

7 Unless otherwise noted, the ELCC derate factors in this section are based on the *ELCC Class Ratings for 2028/2029 Base Residual Auction*, PJM Interconnection L.L.C. (February 25, 2026) <https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/28-29-bra-elcc-class-ratings.pdf>.

8 Unless otherwise noted, the ELCC derate adjusted MW are calculated using the 2028/2029 Base Residual Auction ELCC factors. 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.

- In the first three months of 2026, 40.1 MW from the serial queue went into service. Of the 40.1 MW that went in service, 15.7 MW (39.1 percent) were battery units, 12.6 MW (31.5 percent) were wind units and 11.8 MW (29.4 percent) were solar units.
- Of the 2,809 projects that entered the serial queue from January 1, 2015, through July 10, 2023, 2,062 projects (73.4 percent) were renewable. Of the 690 projects that entered the serial queue in 2020, 545 projects (79.0 percent) were renewable. Renewable projects make up 85.0 percent of all projects in the serial queue and account for 79.0 percent of the nameplate MW currently active, suspended or under construction in the serial queue as of March 31, 2026.
- On March 31, 2026, 28,919.1 MW, on an energy basis, were in generation request serial queues that had reached the construction service agreement milestone or equivalent, in the status of active, suspended or under construction. Of the 28,919.1 MW, 11,200.2 MW (38.7 percent) had not begun construction, 7,551.8 MW (26.1 percent) had begun construction, but are now suspended, and 10,167.1 MW (35.2 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.

New Service Requests Cycle Process[9]

Transition Cycle 1 (TC1)

- Transition cycle 1 (TC1) is comprised of 312 proposed generation projects. Those projects make up 40,650.1 MW. On March 31, 2026, all projects in TC1 were either in the status of active, under construction or were withdrawn from the cycle. Of the 40,650.1 MW in TC1, 14,120 MW (34.7 percent) were active or under construction (10,763.0 MW (26.5 percent) were active and 3,357.0 MW (8.2 percent) were under construction) and 26,530.1 MW (65.3 percent) were withdrawn.
- On March 31, 2026, there were 14,120.0 MW, on an energy basis, of which 6,798.9 MW are on a capacity basis that requested CIRs, in TC1 in the status of active or under construction.
- Of the 6,798.9 MW, on a capacity basis that requested CIRs in TC1 in the status of active or under construction, 1,741.7 MW (25.6 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.
- Of the 569.0 MW, on a capacity basis that requested CIRs, of thermal projects (including CT natural gas projects) requested in TC1 in the status of active or under construction, 381.2 MW (67.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.
- Of the 3,727.4 MW, on a capacity basis that requested CIRs, of solar projects requested in TC1 in the status of active or under construction, 372.7 MW (10.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.
- Of the 1,022.0 MW, on a capacity basis that requested CIRs, of battery projects requested in TC1 in the status of active or under construction, 603.0 MW (59.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.
- Of the 5,207.9 MW, on a capacity basis that requested CIRs, of renewable projects requested in TC1 in the status of active or under construction, 757.5 MW (14.5 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.

Transition Cycle 2 (TC2) and Reliability Resource Initiative (RRI)

- On December 13, 2024, PJM submitted modifications to its Open Access Transmission Tariff to add provisions, through a one-time reliability based expansion of the projects in TC2.[10] On February 11, 2025, the Commission

9 See PJM. Planning. "Cycle Service Request Status," (Accessed on March 31, 2026) <https://www.pjm.com/planning/m/cycle-service-request-status>.

10 See *PJM Interconnection L.L.C.* Docket No. ER25-712 (December 13, 2024).

approved the RRI tariff modifications.[11] The proposed RRI Tariff revisions created a second TC2 application window that enabled RRI projects to join TC2 and be studied for interconnection during the transition period.

- PJM received 97 applications (28.6 GW) of RRI projects during the RRI application window. Of these projects, 48 involved uprates, in which existing resources are modified to increase the economic maximum generation capability, and 49 proposed building new generation. PJM reviewed the submitted RRI projects using the Commission approved scoring criteria, and approved 51 projects (11,577.4 MW).[12] On March 31, 2026, all RRI projects were either in the status of active or withdrawn from the cycle. Of the 11,577.4 MW of approved RRI projects, 7,932.4 MW (68.5 percent) were active and 3,645.0 MW (31.5 percent) were withdrawn.
- Transition cycle 2 (TC2) is comprised of 647 proposed generation projects. TC2 includes 550 projects submitted during the TC2 window, and 97 projects submitted through the RRI window. Those projects make up 77,760.6 MW. On March 31, 2026, all projects in TC2 were either in the status of active, under construction or were withdrawn from the cycle. Of the 77,760.6 MW in TC2, 29,822.6 MW (38.3 percent) were active or under construction (29,742.6 MW (38.2 percent) were active and 80.0 MW (0.1 percent) were under construction) and 47,938.0 MW (61.6 percent) were withdrawn.
- On March 31, 2026, there were 29,822.6 MW, on an energy basis, of which 21,719.2 MW are on a capacity basis that requested CIRs, in TC2 in the status of active or under construction.
- Of the 21,719.2 MW, on a capacity basis that requested CIRs in TC2 in the status of active or under construction, 10,753.4 MW (49.5 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.
- Of the 7,337.9 MW, on a capacity basis that requested CIRs, of thermal projects (including combined cycle and CT natural gas projects) requested in TC2 in the status of active or under construction, 5,642.1 MW (76.9 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.
- Of the 6,366.4 MW, on a capacity basis that requested CIRs, of solar projects requested in TC2 in the status of active or under construction, 636.6 MW (10.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.
- Of the 5,122.3 MW, on a capacity basis that requested CIRs, of battery projects requested in TC2 in the status of active or under construction, 3,022.2 MW (59.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.
- Of the 7,919.1 MW, on a capacity basis that requested CIRs, of renewable projects requested in TC2 in the status of active or under construction, 811.2 MW (10.2 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.

Cycle Process Totals[13]

- On March 31, 2026, there were 959 proposed generation projects in the new services cycle process queues. Those projects make up 118,410.7 MW. On March 31, 2026, all projects in the cycle process queues were either in the status of active, under construction or were withdrawn. Of the 118,410.7 MW in the cycle process queues, 43,942.6 MW (37.1 percent) were active or under construction (40,505.6 MW (34.2 percent) were active and 3,437.0 MW (2.9 percent) were under construction) and 74,468.0 MW (62.9 percent) were withdrawn.
- On March 31, 2026, there were 43,942.6 MW, on an energy basis, of which 28,518.1 MW are on a capacity basis that requested CIRs, in cycle process queues in the status of active or under construction.
- Of the 28,518.1 MW, on a capacity basis that requested CIRs in the cycle process queues in the status of active or under construction, 12,495.1

11 190 FERC ¶ 61,084 (February 11, 2025).

12 The RRI proposal was to select the top 50 projects using the approved scoring criteria. The implemented scoring criteria resulted in a tie for the 50th project. This resulted in PJM selecting 51 projects as part of the RRI process.

13 As of March 31, 2026, the cycle process totals include those projects included in TC1 and TC2.

MW (43.8 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.

- Of the 7,906.9 MW, on a capacity basis that requested CIRs, of thermal projects (including combined cycle and CT natural gas projects) requested in cycle process queues in the status of active or under construction, 6,023.6 MW (76.2 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.
- Of the 10,093.8 MW, on a capacity basis that requested CIRs, of solar projects requested in cycle process queues in the status of active, 1,009.4 MW (10.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.
- Of the 6,144.3 MW, on a capacity basis that requested CIRs, of battery projects requested in cycle process queues in the status of active or under construction, 3,625.1 MW (59.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.
- Of the 13,127.0 MW, on a capacity basis that requested CIRs, of renewable projects requested in cycle process queues in the status of active or under construction, 1,568.6 MW (11.9 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.

Serial and Cycle Process Totals

- On July 10, 2023, there were 287,185.2 MW in the status of active, under construction or suspended in the serial queue. As part of the transition to the new cycle process projects were removed from the queue because developers chose to not resubmit their projects in the TC2 queue, invalid projects were removed and must be resubmitted in Cycle 1, and projects were withdrawn as part of the normal queue process. On March 31, 2026, of the 287,185.2 MW, there were 76,230.9 MW (26.5 percent) in the status of active, in service or under construction, 9,428.1 MW (3.3 percent) went in service, and 201,526.2 MW (70.2 percent) have been withdrawn from the queue.
- On March 31, 2026, there were 6,420 proposed generation projects in the combined serial and new services cycle process queues. Those projects make up 727,638.1 MW. On March 31, 2026, projects in the combined serial and cycle process queues were in the status of active, under construction, suspended, in service or were withdrawn. Of the 727,638.1 MW in the combined serial and cycle process queues, 84,163.3 MW (11.6 percent) were active, under construction or suspended, (60,431.0 MW (8.3 percent) were active, 16,180.5 MW (2.2 percent) were under construction and 7,551.8 MW (1.0 percent) were suspended), 95,178.1 MW (13.1 percent) were in service and 548,296.7 MW (75.4 percent) were withdrawn.
- Of the 84,163.3 MW in the combined serial and cycle process queues in the status of active, under construction or suspended, 13,588.1 MW (16.1 percent) are thermal projects.

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, 2026, PJM has completed six market efficiency cycles under Order No. 1000.[14] In February 2024, PJM completed the 2024/2025 market efficiency base case. In May 2024, PJM posted the 2024/2025 Market Efficiency planning assumptions. The long term market efficiency window opened on April 11, 2025, and closed on June 10, 2025. This window accepted proposals to address historical congestion on three identified flowgates. PJM received 14 proposals from five entities. Two

14 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).

projects, submitted by incumbent transmission owners, were selected as the preferred solutions.[15] These projects were presented to, and approved by, the PJM Board on February 12, 2026. There were no projects selected for acceleration in the 2024/2025 Market Efficiency window.

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."[16] Supplemental projects are exempt from competition.
- The average number of supplemental projects expected in each 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 2026 (post Order 890).[17]

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.[18] In the first three months of 2026, the PJM Board approved $12.2 billion in upgrades. As of March 31, 2026, the PJM Board has approved $70.8 billion in system enhancements since 1999.

15 One of the three identified congestion drivers included in the 2024/2025 Market Efficiency window was addressed in the 2025 RTEP Window 1.

16 See PJM. "Transmission Construction Status," (Accessed on March 31, 2026) <https://www.pjm.com/planning/m/project-construction>.

17 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).

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

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, 2026, 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.[19]
- There were 17,593 transmission outage requests submitted in the first 10 months of the 2025/2026 planning period. Of the requested outages, 74.6 percent were planned for less than or equal to five days and 10.1 percent were planned for greater than 30 days. Of the requested outages, 41.8 percent were submitted late according to the rules in PJM's Manual 3.

Recommendations

Generation Retirements

- The MMU recommends that CIRs 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 power by requiring high payments for CIRs.[20] (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 2024. Status: Not adopted.)

19 See "PJM Manual 03: Transmission Operations," Rev. 70 (March 4, 2026).

20 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>.

- 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.[21] (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.[22] (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.)

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.)[23]
- 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.)[24]
- The MMU recommends that PJM enhance the transparency and queue management process for nonincumbent transmission investment. Issues

21 PJM Filing, FERC Docket No. ER22-2110-000 (June 14, 2022); 181 FERC ¶ 61,162 (2022).

22 Ibid.

23 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).

24 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).

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.[25] (Priority: Medium. First reported 2015. Status: Not adopted.)

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 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 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

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

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.)

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. Rigorous standards that protect customers from risk should be applied to competitive transmission suppliers to ensure that customers receive the benefits of competition.

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.[26] [27]

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. Line ratings should be provided for a range of durations to ensure that operators understand the actual impact of short term flows versus longer term flows when making decisions that affect market prices. 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

26 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.

27 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.

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.

It would be antithetical to competition to permit transmission owners to own black start units under the backstop rules, to own batteries (storage as a transmission asset) or to permit transmission owners to build new generation, all under the antiquated cost of service regulation rules that were displaced by more efficient competitive markets. Such an approach would undermine competitive markets and require market projects built with investors' capital at risk to compete with subsidized resources.

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 is being significantly improved, based on the proposal submitted by PJM on June 14, 2022, and approved by FERC on November 29, 2022.[28] [29] 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 and to reduce uncertainty for new generation.

On March 31, 2026, there were 959 proposed generation projects in the new services cycle process queues. Those projects make up 118,410.7 MW. Of the 118,410.7 MW in the cycle process queues, 43,942.6 MW (37.1 percent) were active or under construction (40,505.6 MW (34.2 percent) were active and 3,437.0 MW (2.9 percent) were under construction and 74,468.0 MW (62.9 percent) were withdrawn. The volume of withdrawn projects in the new cycle process does not necessarily mean that the new process is not effective. It is important to recognize that the timing of the project withdrawals. Under the new cycle queue process, the impact on the studies that account for withdrawn projects and the impacts on other projects in the queue has been significantly reduced. So far, the transition cycles have remained on schedule while managing withdrawn projects.

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 fully in place and it can be evaluated. It will be approximately

28 See *PJM*, Docket No. ER22-2110 (June 14, 2022).
29 See 181 FERC ¶ 61,162 (2022).

two years for the impact of the new cycle process to be known. 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 allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress. There has already been a significant reduction in queue projects as a result of PJM's improvements to the process. 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. Initial results from the transition cycles have shown that developers are withdrawing their projects at the specified decision points, which is helping to remove speculative projects from the queue process sooner. Whether the new cycle process will result in enough new dispatchable and renewable generation to meet system needs cannot be determined until after a full cycle has been completed, projects go in service and completion rates can be evaluated. 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 while ensuring that customers receive the benefits of competition.

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.[30] The Market Monitor filed opposing comments.[31] The Commission rejected the filing, finding (i) "that the lack of a maximum time limit for Commercial Operation Date extensions, which introduces the opportunity to delay commercial operation for an indefinite period of time, would result in a generator replacement process that does not promote the efficient interconnection of new resources;" and (ii) "because the unrestricted opportunity for a Replacement Generation Resource Project Developer to significantly delay commercial operation may result in CIRs and associated transmission capacity dedicated to accommodate the Replacement Generation Resource's operation going unused."[32] PJM filed a new proposal that continued to be flawed.[33] On January 29, 2026, the Commission approved the tariff revisions.[34]

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.[35] [36] 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

30 See PJM Interconnection, L.L.C., Docket No. ER25-1128 (January 31, 2025).
31 See Comments of the Independent Market Monitor for PJM, Docket No. ER25-1128-000 (February 21, 2025).
32 See 192 FERC ¶ 61,137 at PP 38–39 (2025).
33 *See PJM Interconnection, L.L.C.*, Docket No. ER26-403-000 (October 31, 2025).
34 See 194 FERC ¶ 61,079 (January 29, 2026).
35 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>.
36 On April 30, 2024, the CIR Transfer Efficiency issue was transferred from the Interconnection Process Subcommittee (IPS) to the Planning Committee (PC).

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

On February 27, 2026, PJM filed revisions to the tariff to establish an expedited interconnection track (EIT) process for generating facilities.[37] The EIT was designed to expedite the interconnection of new generation that commits to firm commercial in service dates, has a commitment from the relevant siting authority (or a state executive officer in certain circumstances) to expedite consideration of applicable siting, and provides a pathway for new generation.

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.

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. However, 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

37 See PJM. Docket No. ER26-1563 (February 27, 2026).

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.

Recent proposals from Transmission Owners to use storage as a transmission asset (SATA) raises a number of additional concerns about PJM's benefit/cost analysis. Storage is a market asset and should not be owned by transmission owners. PJM should not be evaluating SATA at all without a decision from FERC that SATA is allowable in PJM. At present, it is not allowed.

A significant flaw in PJM's benefit/cost analysis is that projected benefits are based on load forecasts which are currently dominated by projected large data center loads that are not verified by PJM and cannot be verified by PJM. That creates a bias towards finding transmission projects beneficial despite the fact that data center loads are imposing transmission costs on other customers as a result.

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.[38]

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 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

38 PJM, "Manual 38: Operations Planning," Rev. 20 (January 22, 2026) at 19-20.

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.[39] 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 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.

39 OATT Part V §114.

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.[40] 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.

40 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 Virginia case illustrates the imposition of transmission costs by data centers on other PJM customers. These additional transmission costs are in addition to the significant capacity market costs imposed on other customers by the actual and forecast addition of large data centers.

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 data center 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 simply 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 (assumed) consistent with the procedures noted in Manual 14B.[41] [42] The RTEP analysis is not adequately coordinated with PJM markets analysis including the energy and capacity markets. In effect, the RTEP process could result in building expensive transmission based on speculation about the location and type of capacity additions and load additions. The related impacts are exacerbated by the uncertainty about the actual additions of large data centers. This approach to planning is inefficient and unsustainable.

41 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>.

42 See "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 58 (December 17, 2025).

Generation Interconnection Planning

Existing Generation Mix

Table 12-1 shows the existing PJM capacity by control zone and unit type.[43] [44] As of March 31, 2026, PJM had an installed capacity of 203,028.6 MW, of which 38,366.4 MW (18.9 percent) are coal fired steam units, 57,047.4 MW (28.1 percent) are combined cycle units and 33,452.6 MW (16.5 percent) are nuclear units. This measure of installed capacity differs from capacity market installed capacity because it includes energy only units, external units and uses nameplate values for solar and wind resources.

The AEP Zone has the most installed capacity of any PJM zone. Of the 203,028.6 MW of PJM installed capacity, 38,374.3 MW (18.9 percent) are in the AEP Zone, of which 13,463.0 MW (35.1 percent) are coal fired steam units, 9,294.0 MW (24.2 percent) are combined cycle units and 2,071.0 MW (5.4 percent) are nuclear units.

Table 12-1 Existing capacity: March 31, 2026 (By zone and unit type (MW))[45]

Zone	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
ACEC	0.0	781.6	395.5	0.0	0.0	1.6	0.0	0.0	0.0	0.0	4.0	5.4	68.8	0.0	0.0	0.0	0.0	0.0	0.0	7.5	0.0	1,264.3
AEP	0.0	9,294.0	4,028.2	16.2	4.8	0.0	66.0	420.9	2,071.0	0.0	0.0	20.4	4,610.6	0.0	0.0	13,463.0	738.0	0.0	0.0	3,641.2	0.0	38,374.3
AMPT	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
APS	33.0	2,843.7	1,223.3	0.0	2.0	0.0	0.0	129.2	0.0	22.4	0.0	18.3	642.8	0.0	0.0	5,119.0	0.0	0.0	0.0	1,040.0	0.0	11,073.7
ATSI	0.0	5,571.0	1,383.0	183.0	6.4	0.0	0.0	0.0	2,134.0	0.0	5.5	4.7	757.0	0.0	0.0	0.0	325.0	0.0	136.0	0.0	0.0	10,505.6
BGE	3.5	0.0	267.6	215.9	0.0	0.0	0.0	0.0	1,716.0	0.0	0.0	4.2	31.1	0.0	0.0	1,273.0	17.5	702.0	57.0	0.0	0.0	4,287.8
COMED	104.5	4,631.1	6,753.3	226.2	0.0	0.0	0.0	0.0	10,473.5	0.0	0.0	15.0	59.0	0.0	0.0	2,646.0	0.0	0.0	0.0	5,633.2	0.0	30,541.8
DAY	0.0	0.0	897.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	34.0	0.0	742.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,674.3
DUKE	10.0	522.2	598.0	56.0	0.0	0.0	0.0	112.0	0.0	0.0	0.0	4.8	289.9	0.0	0.0	1,252.0	47.0	0.0	0.0	0.0	0.0	2,891.9
DUQ	0.0	306.0	0.0	15.0	0.0	0.0	0.0	6.3	1,777.0	14.4	0.0	0.0	54.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,172.9
DOM	34.7	9,138.0	3,835.3	256.4	10.0	0.0	3,003.0	586.3	3,581.3	0.0	18.0	94.7	5,556.8	0.0	0.0	2,473.2	55.0	0.0	318.4	790.0	0.0	29,751.1
DPL	0.0	1,742.5	978.2	478.2	0.0	30.0	0.0	0.0	0.0	0.0	86.0	14.1	586.0	0.0	0.0	0.0	710.0	153.0	70.0	0.0	0.0	4,848.0
EKPC	0.0	0.0	774.0	0.0	0.0	0.0	0.0	136.0	0.0	0.0	0.0	0.0	205.0	0.0	0.0	1,687.0	0.0	0.0	0.0	0.0	0.0	2,802.0
JCPLC	192.8	2,115.5	748.0	0.0	0.0	0.4	140.0	0.0	0.0	0.0	0.0	0.0	477.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,674.5
MEC	0.0	2,595.0	2.0	398.5	0.0	0.0	0.0	19.0	0.0	0.0	0.0	30.9	430.0	0.0	0.0	80.0	35.0	0.0	60.0	0.0	0.0	3,650.4
OVEC	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	2,388.8	0.0	0.0	0.0	0.0	0.0	2,388.8
PECO	0.0	4,089.0	0.0	828.0	0.0	0.0	1,070.0	572.0	4,546.8	0.0	0.0	0.9	3.0	0.0	0.0	0.0	765.3	0.0	103.0	0.0	0.0	11,978.0
PE	28.4	1,900.0	422.1	57.0	0.0	0.0	513.0	77.8	0.0	120.1	28.0	11.0	338.4	0.0	0.0	4,169.5	610.0	0.0	42.0	1,238.0	0.0	9,555.3
PEPCO	0.0	1,736.5	770.2	258.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.7	35.6	0.0	0.0	0.0	1,164.1	0.0	52.0	0.0	0.0	4,025.1
PPL	20.0	5,558.5	234.0	36.0	20.6	0.0	0.0	706.6	2,520.0	12.0	5.0	14.7	220.0	0.0	0.0	1,859.9	3,137.0	0.0	29.0	216.5	0.0	14,589.8
PSEG	7.7	4,223.1	963.2	0.0	0.0	0.0	0.0	5.0	3,493.0	0.0	0.0	9.0	230.3	0.0	0.0	0.0	3.0	0.0	179.1	0.0	0.0	9,113.3
XIC	0.0	0.0	670.6	0.0	0.0	0.0	0.0	0.0	1,140.0	0.0	0.0	0.0	0.0	0.0	0.0	1,955.0	0.0	0.0	0.0	100.0	0.0	3,865.6
Total	434.6	57,047.7	24,944.0	3,024.4	43.8	32.0	4,792.0	2,771.1	33,452.6	168.9	180.5	256.8	15,339.0	0.0	0.0	38,366.4	7,606.9	855.0	1,046.5	12,666.4	0.0	203,028.6

43 The unit type RICE refers to Reciprocating Internal Combustion Engines.
44 XIC refers to external installed capacity.
45 The capacity described in this section refers to all capacity in PJM at the summer installed capacity rating, regardless of whether the capacity entered the RPM Auction.

Table 12-2 shows the installed capacity by state for each fuel type. Pennsylvania has the most installed capacity of any PJM state. Of the 203,028.6 MW of installed capacity, 47,536.4 MW (23.4 percent) are in Pennsylvania, of which 6,109.4 MW (12.9 percent) are coal fired steam units, 18,292.2 MW (38.5 percent) are combined cycle units and 8,843.8 MW (18.6 percent) are nuclear units.

Table 12-2 Existing capacity: March 31, 2026 (By state and unit type (MW))

State	Battery	Combined Cycle	CT – Natural Gas	CT – Oil	CT – Other	Fuel Cell	Hydro – Pumped Storage	Hydro – Run of River	Nuclear	RICE – Natural Gas	RICE – Oil	RICE – Other	Solar	Solar + Storage	Solar + Wind	Steam – Coal	Steam – Natural Gas	Steam – Oil	Steam – Other	Wind	Wind + Storage	Total
DC	0.0	19.5	6.0	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	25.5
DE	0.0	742.5	325.5	116.3	0.0	30.0	0.0	0.0	0.0	0.0	0.0	8.1	50.0	0.0	0.0	0.0	710.0	0.0	70.0	0.0	0.0	2,052.4
IL	104.5	4,631.1	6,753.3	226.2	0.0	0.0	0.0	0.0	10,473.5	0.0	0.0	15.0	59.0	0.0	0.0	2,646.0	0.0	0.0	0.0	5,633.2	0.0	30,541.8
IN	0.0	1,835.0	441.4	0.0	0.0	0.0	0.0	8.2	0.0	0.0	0.0	3.2	1,432.6	0.0	0.0	3,923.8	0.0	0.0	0.0	2,353.2	0.0	9,997.4
KY	0.0	0.0	1,618.1	0.0	0.0	0.0	0.0	136.0	0.0	0.0	0.0	0.0	382.0	0.0	0.0	1,687.0	278.0	0.0	0.0	0.0	0.0	4,101.1
MD	3.5	2,717.0	1,684.5	489.8	0.0	0.0	0.0	0.0	1,716.0	0.0	74.0	18.9	873.7	0.0	0.0	1,273.0	1,181.6	855.0	191.0	349.9	0.0	11,427.9
MI	0.0	994.0	0.0	0.0	4.8	0.0	0.0	11.8	2,071.0	0.0	0.0	3.2	4.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,089.4
NC	0.0	165.0	0.0	0.0	0.0	0.0	0.0	315.0	0.0	0.0	18.0	0.0	1,321.5	0.0	0.0	0.0	0.0	0.0	0.0	397.0	0.0	2,216.5
NJ	200.5	7,120.2	2,106.7	0.0	0.0	2.0	140.0	5.0	3,493.0	0.0	4.0	14.4	776.8	0.0	0.0	0.0	3.0	0.0	179.1	7.5	0.0	14,052.1
OH	10.0	11,558.2	4,626.2	255.2	6.4	0.0	0.0	200.0	2,134.0	0.0	34.0	9.5	4,445.1	0.0	0.0	6,820.0	47.0	0.0	136.0	1,288.0	0.0	31,569.6
PA	49.9	18,292.2	1,545.5	1,334.5	20.6	0.0	1,583.0	1,445.7	8,843.8	168.9	38.5	75.8	1,202.4	0.0	0.0	6,109.4	4,872.3	0.0	234.0	1,719.9	0.0	47,536.4
TN	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
VA	34.7	8,973.0	4,092.3	591.4	12.0	0.0	3,069.0	460.1	3,581.3	0.0	12.0	100.7	4,671.3	0.0	0.0	1,468.2	515.0	0.0	236.4	26.0	0.0	27,843.4
WV	31.5	0.0	1,073.9	11.0	0.0	0.0	0.0	189.3	0.0	0.0	0.0	8.0	120.0	0.0	0.0	12,484.0	0.0	0.0	0.0	791.7	0.0	14,709.4
XIC	0.0	0.0	670.6	0.0	0.0	0.0	0.0	0.0	1,140.0	0.0	0.0	0.0	0.0	0.0	0.0	1,955.0	0.0	0.0	0.0	100.0	0.0	3,865.6
Total	434.6	57,047.7	24,944.0	3,024.4	43.8	32.0	4,792.0	2,771.1	33,452.6	168.9	180.5	256.8	15,339.0	0.0	0.0	38,366.4	7,606.9	855.0	1,046.5	12,666.4	0.0	203,028.6

Table 12-3 and Figure 12-1 show the age of existing PJM generators, by unit type, as of March 31, 2026. Of the 203,028.6 MW of installed capacity, 75,558.5 MW (37.2 percent) are from units older than 40 years, of which 30,814.3 MW (40.8 percent) are coal fired steam units, 255.0 MW (0.3 percent) are combined cycle units and 25,550.6 MW (33.8 percent) are nuclear units.

Table 12-3 Capacity (MW) by unit type and age (years): March 31, 2026

Age (years)	Battery	Combined Cycle	CT – Natural Gas	CT – Oil	CT – Other	Fuel Cell	Hydro – Pumped Storage	Hydro – Run of River	Nuclear	RICE – Natural Gas	RICE – Oil	RICE – Other	Solar	Solar + Storage	Solar + Wind	Steam – Coal	Steam – Natural Gas	Steam – Oil	Steam – Other	Wind	Wind + Storage	Total
Less than 20	434.6	36,580.4	2,404.4	0.0	43.8	32.0	0.0	293.6	0.0	134.5	0.0	150.3	15,339.0	0.0	0.0	2,440.0	82.0	0.0	47.4	12,450.4	0.0	70,432.3
20 to 40	0.0	20,212.3	22,074.8	478.0	0.0	0.0	0.0	117.3	7,902.0	34.4	22.0	90.7	0.0	0.0	0.0	5,112.1	70.0	0.0	708.1	216.0	0.0	57,037.7
40 to 60	0.0	255.0	350.8	2,517.7	0.0	0.0	4,586.0	383.1	25,550.6	0.0	140.5	15.8	0.0	0.0	0.0	27,785.5	4,829.4	855.0	85.0	0.0	0.0	67,354.4
Greater than 60	0.0	0.0	114.0	28.7	0.0	0.0	206.0	1,977.1	0.0	0.0	18.0	0.0	0.0	0.0	0.0	3,028.8	2,625.5	0.0	206.0	0.0	0.0	8,204.1
Total	434.6	57,047.7	24,944.0	3,024.4	43.8	32.0	4,792.0	2,771.1	33,452.6	168.9	180.5	256.8	15,339.0	0.0	0.0	38,366.4	7,606.9	855.0	1,046.5	12,666.4	0.0	203,028.6

Figure 12-1 Capacity (MW) by age (years): March 31, 2026

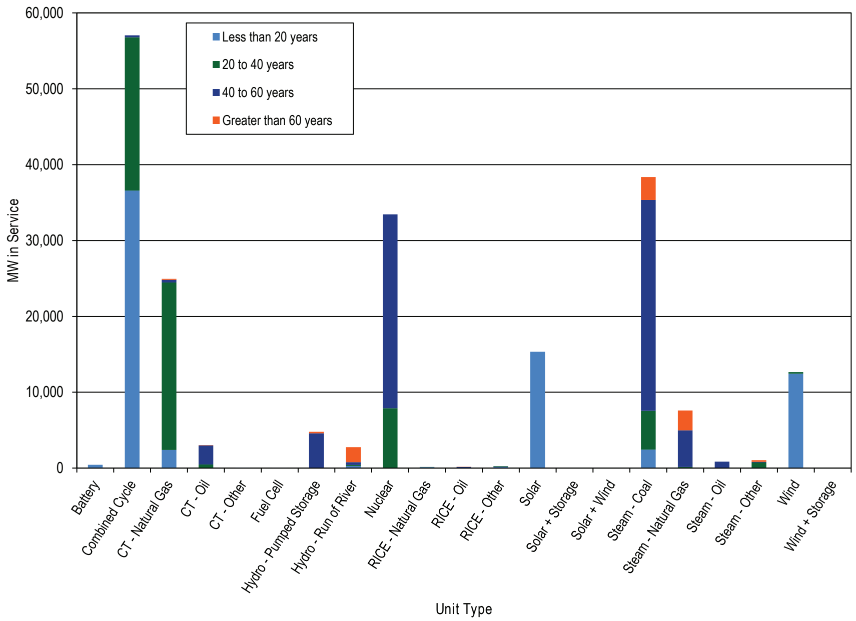


Figure 12-2 is a map of units, less than 20 MW in size that came online between January 1, 2011, and March 31, 2026. A mapping to these unit names is in Table 12-4.

Figure 12-2 Map of unit additions (less than 20 MW): January 1, 2011 through March 31, 2026

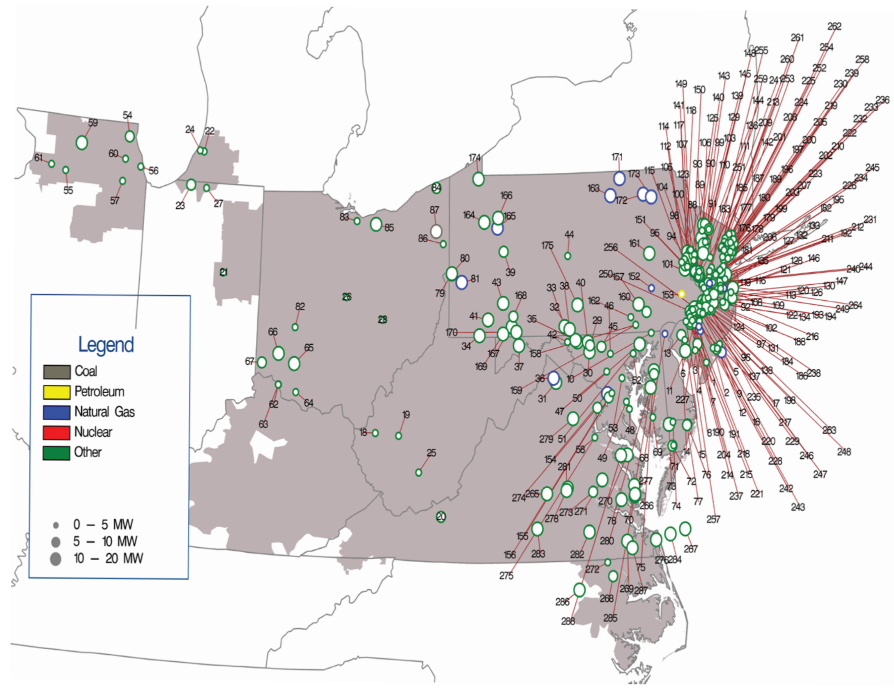


Table 12-4 Unit identification for map of unit additions (less than 20 MW): January 1, 2011 through March 31, 2026

ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit
1	ACE CAPE MAY COUNTY 1 LF	56	COM GRAND RIDGE 6 BT	111	JC FRENCHTOWN 2 SP	166	PN COBALT 1 SP	221	PS MANTUA CREEK 7 BT	276	VP OCEANA 1 SP
2	ACE CATES ROAD 2 SP	57	COM MAGID GLOVE 1 BT	112	JC FRENCHTOWN 3 SP	167	PN GARRETT 1 BT	222	PS MARION SOLAR 1 SP	277	VP PULLER 1 SP
3	ACE CEDAR BRANCH 1 SP	58	COM MORRIS 1 LF	113	JC HANOVER 2 SP	168	PN LAUREL HIGHLANDS 2 LF	223	PS MATRIX PA SOLAR 2 SP	278	VP QUILLWORT 4 SP
4	ACE EGG HARBOR-KELLOGG 1 FC	59	COM ORCHARD 1 LF	114	JC HARMONY 1 SP	169	PN LISTONBURG 1 SP	224	PS MAYWOOD SOLAR 1 SP	279	VP REMINGTON 1 SP
5	ACE GALLOWAY LANDFILL 2 SP	60	COM SOLBERG 1 BT	115	JC HIGH STREET 6 SP	170	PN MEYERSDALE 2 BT	225	PS METRO HQ 2 SP	280	VP ROCHAMBEAU 1 SP
6	ACE GEMS LANDFILL 1 SP	61	COM STERLING RAIL 1 BT	116	JC HOFFMAN STATION ROAD 2 SP	171	PN MILAN ENERGY 1 D	226	PS MIDDLESEX 1 SP	281	VP SCOTT - POWHATAN 3 HB
7	ACE KETTLE RUN 1 SP	62	DEOK BECKJORD 1 BT	117	JC HOLLAND 4 SP	172	PN NORTH MESHOPPEN 1 CT	227	PS MILL CREEK 1 SP	282	VP SHANDS ENERGY 2 BT
8	ACE MAYS LANDING 1 SP	63	DEOK BECKJORD 2 BT	118	JC HOLLAND-MORRISPA 8 SP	173	PN OXBOW CREEK ENERGY CENTER 1 D	228	PS MOORESTOWN 1 SP	283	VP TWITTYS CREEK 1 SP
9	ACE MIDTOWN THERMAL 2 CT	64	DEOK BROWN COUNTY 1 LF	119	JC HOLMDEL 9 SP	174	PN SAMARITAN 1 SP	229	PS MT LAUREL 1 SP	284	VP VIRGINIA OFFSHORE 1 WF
10	ACE MONROE - SICKLERVILLE 1 SP	65	DEOK CLINTON 1 BT	120	JC HOWELL 1 SP	175	PN WHITETAIL 1 SP	230	PS NEW MILFORD SOLAR 1 SP	285	VP WAN - GLOUCESTER 1 SP
11	ACE OAK FAIRTON 1 SP	66	DEOK NICKEL - CIN ZOO 1 SP	121	JC HOWELL 4 BT	176	PS ALDENE SOLAR 1 SP	231	PS NEW ROAD 1 SP	286	VP WHITAKERS 1 SP
12	ACE PEAR STREET 1 SP	67	DEOK WILLEY 1 BT	122	JC JACOBSTOWN 1 SP	177	PS ATHENIA SOLAR 1 SP	232	PS NEWARK SOLAR 1 SP	287	VP WHITE MARSH - SUFFOLK 1 SP
13	ACE PILESGROVE 1 SP	68	DPL BLOOM ENERGY 1 FC	123	JC JUNCTION ROAD 6 SP	178	PS BAYONNE 1 SP	233	PS NEWARK SOLAR 3 SP	288	VP WOODBINE ROAD 1 SP
14	ACE PILESGROVE 2 SP	69	DPL BUCKTOWN 1 SP	124	JC LAKEHURST 3 SP	179	PS BAYONNE SOLAR 2 SP	234	PS NIXON LANE 2 SP		
15	ACE PITTSGROVE 1 SP	70	DPL CHURCH HILL 1 SP	125	JC LEBANON 1 SP	180	PS BELLEVILLE SOLAR 1 SP	235	PS NORTH AMERICAN 4 SP		
16	ACE SEASHORE 1 SP	71	DPL COSTEN 1 SP	126	JC LEGLER LANDFILL 7 SP	181	PS BENNETTS SOLAR 1 SP	236	PS NORTH AVE SOLAR 1 SP		
17	ACE TANSBORO ROAD 1 FC	72	DPL COSTEN 2 SP	127	JC MANALAPAN 1 SP	182	PS BLACK ROCK 1 SP	237	PS OWENS CORNING 1 SP		
18	AEP BALLS GAP 1 BT	73	DPL HEBRON 1 SP	128	JC MILLHURST 3 SP	183	PS BRIDGEWATER SOLAR 2 SP	238	PS PARKLANDS 1 SP		
19	AEP CHARLESTON 1 LF	74	DPL KUMQUAT 1 SP	129	JC MOUNT OLIVE 3 SP	184	PS BUSTLETON 2 SP	239	PS PATERSON PLANK ROAD 1 SP		
20	AEP CLOYDS MT 1 LF	75	DPL PONDTOWN 1 SP	130	JC MUDDY FORGE 3 SP	185	PS CALDWELL PUMP 2 BT	240	PS PENNINGTON 3 BT		
21	AEP DEERCREEK 1 SP	76	DPL WORCESTER NORTH 1 SP	131	JC NORTH HANOVER 4 SP	186	PS CAMPUS DRIVE 2 SP	241	PS PENNINGTON 4 SP		
22	AEP EAST WATERVLIET 1 SP	77	DPL WORCESTER SOUTH 2 SP	132	JC NORTH PARK 1 SP	187	PS CEDAR GROVE SOLAR 1 SP	242	PS PENNSAUKEN 1 LF		
23	AEP OLIVE 1 SP	78	DPL WYE MILLS 1 SP	133	JC NORTH PARK 2 SP	188	PS CEDAR LANE FLORENCE 6 SP	243	PS PENNSAUKEN 3 SP		
24	AEP ORCHARD HILLS 1 LF	79	DUQ BE-PINE 1 SP	134	JC NORTH RUN 11 SP	189	PS COOK ROAD SOLAR 2 SP	244	PS PRINCETON HOSPITAL 1 CT		
25	AEP RALEIGH COUNTY 1 LF	80	DUQ BE-PINE 2 SP	135	JC OLD BRIDGE 1 SP	190	PS COOPER HOSPITAL 1 BT	245	PS RARITAN CENTER 3 SP		
26	AEP TRENT 1 BT	81	DUQ PIT MICROGRID 1 CT	136	JC PAUCH 3 SP	191	PS COOPER HOSPITAL 15 SP	246	PS REEVES EAST 3 SP		
27	AEP TWINBRANCH 1 SP	82	FE DOVETAIL 1 CT	137	JC PEMBERTON 1 SP	192	PS CRANBURY 2 SP	247	PS REEVES SOUTH 1 SP		
28	AEP ZANESVILLE 2 LF	83	FE ERIE COUNTY 1 LF	138	JC PEMBERTON 2 SP	193	PS CROSSWIC 1 SP	248	PS REEVES WEST 4 SP		
29	AP BAKER POINT 1 SP	84	FE GENEVA 1 LF	139	JC QUAKERTOWN 12 SP	194	PS CROSSWIC 2 SP	249	PS RIDER UNIVERSITY 3 SP		
30	AP BIGGS FORD 1 SP	85	FE LORAIN 1 LF	140	JC QUAKERTOWN 9 SP	195	PS DEVILSBROOK 1 SP	250	PS RIVER ROAD 2 SP		
31	AP DOUBLE TOLLGATE SP	86	FE MAHONING 1 LF	141	JC RICHLINE 3 SP	196	PS DOREMUS SOLAR 1 SP	251	PS ROSELAND SOLAR 1 SP		
32	AP EAST HAGERSTOWN 1 SP	87	FE WARREN-EVERGREEN 1 CT	142	JC RINGOES 1 SP	197	PS E RUTHERFORD SOLAR 1 SP	252	PS RUTGERS GENERATION 1 F		
33	AP ELK HILL 1 SP	88	JC AUGUSTA 1 SP	143	JC ROY ROAD 5 BT	198	PS EASTAMPTON 1 SP	253	PS SADDLE BROOK SOLAR 1 SP		
34	AP GANS 5 SP	89	JC BEAVER RUN 3 SP	144	JC SOUTH COMBE 2 SP	199	PS EDISON 1 SP	254	PS SPRINGFIELD SOLAR 1 SP		
35	AP HAGERSTOWN 1 SP	90	JC BERKSHIRE 2 SP	145	JC SUSSEX 1 LF	200	PS ESSEX 105 CT	255	PS SUNNYMEADE SOLAR 1 SP		
36	AP HP HOOD 1 CT	91	JC BERNARDS TOWNSHIP 1 SP	146	JC TINTON FALLS 3 SP	201	PS FAIRLAWN SOLAR 1 SP	256	PS TAYLORS LANE 1 SP		
37	AP JADE MEADOW 1 SP	92	JC BRICKYARD 4 SP	147	JC UPPER FREEHOLD 1 SP	202	PS FOODBANK 1 SP	257	PS THOROFARE SOLAR 2 SP		
38	AP LETZBURG - ELK HILL 2 SP	93	JC BRIGHT ROAD 2 BT	148	JC WANTAGE 2 SP	203	PS FORTY NINTH SOLAR 1 SP	258	PS TURNPIKE 1 SP		
39	AP MAHONING CREEK 1 H	94	JC COPPER HILL 4 SP	149	JC WARREN 1 SP	204	PS GLOUCESTER SOLAR 1 SP	259	PS W CALDWELL SOLAR 1 SP		
40	AP MT ST MARYS PV PARK 2 SP	95	JC CYPHERS ROAD 5 SP	150	JC WASHBURN AVE 4 SP	205	PS HACKENSACK 1 SP	260	PS W CALDWELL SOLAR 2 SP		
41	AP PECHIN 2 SP	96	JC DIXSOLAR 51 SP	151	ME GLENDON 1 LF	206	PS HIGHLAND PARK 3 BT	261	PS WALDWICK SOLAR 1 SP		
42	AP PINESBURG 1 SP	97	JC DIXSOLAR 52 SP	152	ME READING HOSPITAL 1 CT	207	PS HIGHLAND PARK 4 SP	262	PS WEST ORANGE SOLAR 1 SP		
43	AP SPRING LANE 1 SP	98	JC DOMIN LANE 1 SP	153	PE MORRIS ROAD 1 D	208	PS HILLSDALE SOLAR 1 SP	263	PS WEST PEMBERTON 1 SP		
44	AP STATE COLLEGE 1 BT	99	JC DURBAN AVENUE 1 SP	154	PEP CAPITAL POWER PLANT 1 CT	209	PS HINCHMANS SOLAR 1 SP	264	PS WEST WINDSOR 1 CT		
45	AP UNION BRIDGE 1 SP	100	JC E FLEMINGTON 5 SP	155	PEP ROLLINS AVENUE 3 SP	210	PS HOBOKEN SOLAR 2 SP	265	VP BUCKINGHAM 1 SP		
46	BC ALPHA RIDGE 1 LF	101	JC EAST AMWELL 7 SP	156	PEP SPECTRUM 1 SP	211	PS HOPEWELL 1 SP	266	VP CAMELLIA - WAN 2 SP		
47	BC BRIGHTON DAM 1 H	102	JC EGYPT 3 SP	157	PL DART CONTAINER 1-2 LF	212	PS HOPEWELL 2 BT	267	VP COASTAL VIRGINIA T2G07 - 2 WF		
48	BC CHESAPEAKE BEACH 1 BT	103	JC FISCHER 8 SP	158	PL HOLTWOOD 11	213	PS JACKSON SOLAR 1 SP	268	VP COLICE HALL 1 SP		
49	BC FAIRHAVEN 2 BT	104	JC FOUL RIFT 8 SP	159	PL HOLTWOOD 13	214	PS KINSLEY BEAVER 2 SP	269	VP GARDNER FARMS 1 SP		
50	BC FAIRVIEW - OTTERPT 1SP	105	JC FOUL RIFT ROAD 1 SP	160	PL KEYSTONE 1 SP	215	PS KINSLEY DEPTFORD 1 SP	270	VP GARDYS MILL ROAD 5 SP		
51	BC FAIRVIEW - OTTERPT 2SP	106	JC FRANKFORD 4 SP	161	PL PA SOLAR 1 SP	216	PS KUSER SOLAR 1 SP	271	VP HOLLYFIELD 1 SP		
52	BC KINGSVILLE 1 SP	107	JC FRANKLIN 7 SP	162	PL TURKEY HILL 1 WF	217	PS LANDFILL 5 SP	272	VP MURPHY 1 SP		
53	BC MILLERSVILLE 1 LF	108	JC FREEMALL 1 FC	163	PN ALPACA GLORY BARN 1 D	218	PS LAWNSIDE 14 BT	273	VP NORTHEAST 2 LF		
54	COM COUNTRYSIDE 1 LF	109	JC FRENCHES 2 SP	164	PN CARDINAL - CLARKSUM 1 SP	219	PS LEONIA SOLAR 1 SP	274	VP OCCOQUAN 1 LF		
55	COM DIXON LEE 5 LF	110	JC FRENCHTOWN 1 SP	165	PN CLARION BOARDS 2 CT	220	PS LUMBERTON STACY HAINES 5 SP	275	VP OCCOQUAN 2 LF		

Figure 12-3 is a map of units, 20 MW or greater in size, that came online between January 1, 2011, and March 31, 2026. A mapping to these unit names is in Table 12-5.

Figure 12-3 Map of unit additions (20 MW or greater): January 1, 2011 through March 31, 2026

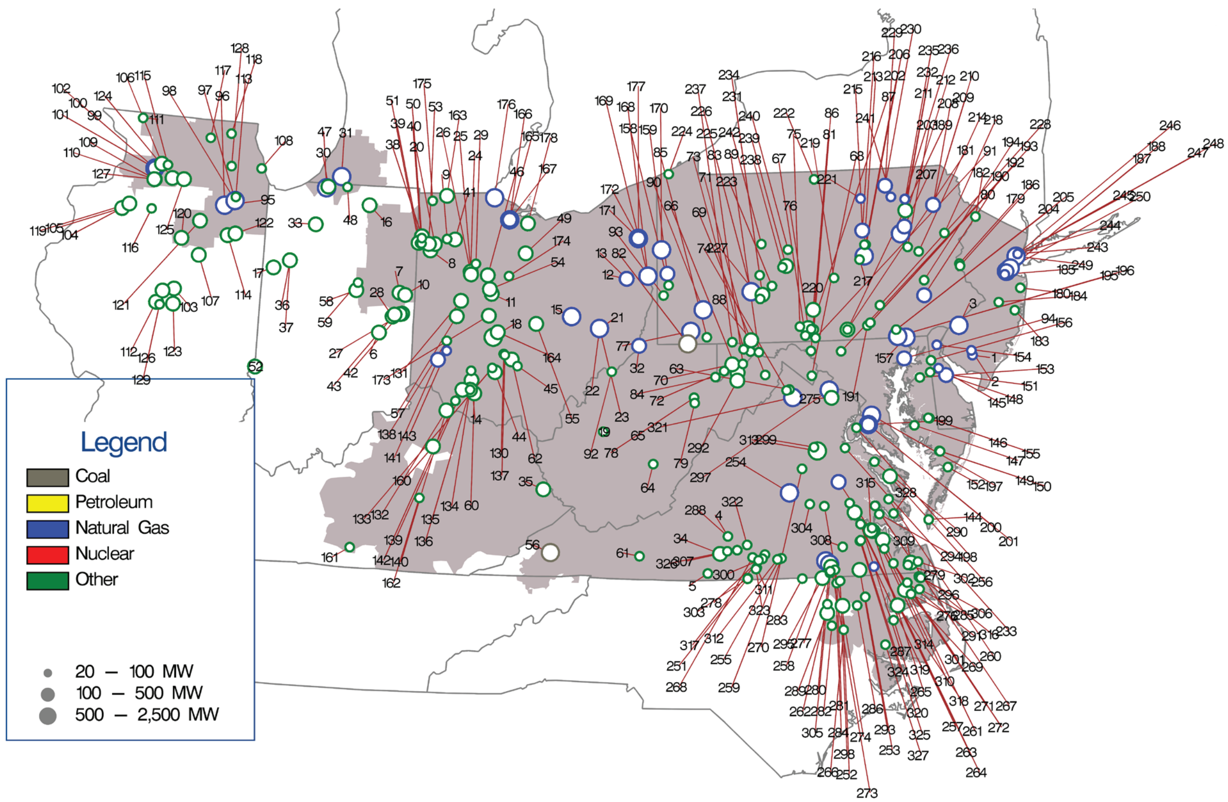


Table 12-5 Unit identification for map of unit additions (20 MW or greater): January 1, 2011 through March 31, 2026

ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit
1	ACE CLAYVILLE 1 CT	56	AEP VIRGINIA CITY 1 F	111	COM HIGHPOINT 11 SP	166	FE FREMONT 2 SCCT	221	PN BEAVER DAM 1 D	276	VP ELIZABETH CITY 1 SP
2	ACE VINELAND 11 CT	57	AEP WAPAHANI - RIVERSTART IV 1 SP	112	COM HILLTOPPER 1 WF	167	FE FREMONT ENERGY CENTER 3 CC	222	PN BIG LEVEL 1 WF	277	VP FOUNTAIN CREEK 1 SP
3	ACE WEST DEPTFORD CROWN POINT 1 CC	58	AEP WILDCAT 1A WF	113	COM JOLIET 1 BT	168	FE HIBBETS MILL SOUTHFIELD 1 CC	223	PN CHESTNUT FLATS 1 WF	278	VP FOXHOUND 1 SP
4	AEP ALTAVISTA 1 SP	59	AEP WILDCAT 1B WF	114	COM KELLY CREEK 1 WF	169	FE HIBBETS MILL SOUTHFIELD 2 CC	224	PN ERIE 1 SP	279	VP GRASSFIELD 1 SP
5	AEP AXTON 1 SP	60	AEP WILLOWBROOK 1 SP	115	COM LEE DEKALB 3 BT	170	FE HICKORY RUN 1 CC	225	PN FAIRVIEW 1 CC	280	VP GREENSVILLE 1 CC
6	AEP BELLFLOWER 1 SP	61	AEP WYTHE COUNTY 1 SP	116	COM LONE TREE 3 WF	171	FE LORDSTOWN ENERGY CENTER 1 CC	226	PN FAIRVIEW 2 CC	281	VP GUTENBERG - OCONECHE 1 SP
7	AEP BITTER RIDGE 1 WF	62	AEP YELLOWBUD 1 SP	117	COM MARENGO 1 BT	172	FE LORDSTOWN ENERGY CENTER 2 CC	227	PN HIGHLAND NORTH 2 WF	282	VP HARTS MILL 1 SP
8	AEP BLUE CREEK 3 WF	63	AP BARTONSVILLE 1 SP	118	COM MCHENRY 1 BT	173	FE MADISON FIELDS 1 SP	228	PN LAUREL HILLS 1 WF	283	VP HAWTREE CREEK 1 SP
9	AEP BLUE HARVEST 1 SP	64	AP BEECH RIDGE 2 WF	119	COM MIDLAND 1 WF	174	FE MARION COUNTY 1 SP	229	PN LIBERTY ASYLUM 10 F	284	VP IVORY LANE 1 SP
10	AEP BLUFF POINT 2 WF	65	AP BEECH RIDGE 3 BT	120	COM MINONK 1 WF	175	FE MONTPELIER 1 SP	230	PN LIBERTY ASYLUM 20 F	285	VP IVY NECK 2 SP
11	AEP CADENCE 1 SP	66	AP BLACK ROCK 1 WF	121	COM OTTER CREEK 1 WF	176	FE OREGON ENERGY CENTER 1 CC	231	PN MAPLE HILL-FIDDLERS 1 SP	286	VP KELFORD 1 SP
12	AEP CARROLL COUNTY 1 CC	67	AP BLAIRS VALLEY 12 SP	122	COM PILOT HILL 1 WF	177	FE TRUMBULL EC 1 CC	232	PN MEHOOPANY 1 WF	287	VP MACKEYS ALBERMAE 1 SP
13	AEP CARROLL COUNTY 2 CC	68	AP BLAKE 1 SP	123	COM RADFORDS RUN 1 WF	178	FE WHEATSBOROUGH 1 SP	233	PN MEHOOPANY 2 WF	288	VP MECHANICSVILLE 2 SP
14	AEP DODSON CREEK 1 SP	69	AP CAPON BRIDGE 1 SP	124	COM SHADY OAKS 1 WF	179	JC EDGE ROAD 5 BT	234	PN PATTON 1 WF	289	VP MOCCASIN CREEK - FERN 1 SP
15	AEP DRESDEN 1 CC	70	AP CPV BACKBONE 1 SP	125	COM SHADY OAKS 2 WF	180	JC HAMILTON ROAD 5 SP	235	PN PGCOGEN 1 CT	290	VP MONTROSS 1 SP
16	AEP ELKHART COUNTY - MCNUTT 1 SP	71	AP DANS MOUNTAIN 1 WF	126	COM TOP HAT 1 WF	181	JC JUSTIN COURT 10 BT	236	PN PGCOGEN 2 CT	291	VP MORGAN CORNER 1 SP
17	AEP FOWLER RIDGE 4 WF	72	AP FAIR WIND 2 WF	127	COM WALNUT RIDGE 1 WF	182	JC MONTAGUE STORAGE 3 BT	237	PN RINGER HILL 1 WF	292	VP NEW CREEK 1 WF
18	AEP FOX SQUIRREL 1 SP	73	AP FOURMILE RIDGE 1 WF	128	COM WEST CHICAGO 3 BT	183	JC OAK RIDGE 3 SP	238	PN SANDY RIDGE 1 WF	293	VP NEWSOMS 1 SP
19	AEP GREAT BEND 1 SP	74	AP FOXGLOVE 1 SP	129	COM WHITNEY HILL 2 WF	184	JC PLUMSTED ENERGY 6 BT	239	PN SANDY RIDGE 2 WF	294	VP NORGE 2 SP
20	AEP GROVER HILL 1 WF	75	AP GREAT COVE 1 SP	130	DAY BUCKEYE PLAINS 2 SP	185	JC SAYREVILLE 3 CT	240	PN SCHOOL HOUSE 1 SP	295	VP OAK 1 SP
21	AEP GUERNSEY 11 CC	76	AP GREAT COVE 2 SP	131	DAY CLEARVIEW 1 SP	186	JC WARREN GLEN 6 BT	241	PN SUGAR RUN 2 CT	296	VP OAK TRAIL 1 SP
22	AEP GUERNSEY 21 CC	77	AP GREENE COUNTY 1 CC	132	DAY CLINTON - EASTFORK 1 SP	187	JC WOODBRIDGE 1 CC	242	PN VIADUCT 1 SP	297	VP PANDA STONEWALL 1 CC
23	AEP GUERNSEY 31 CC	78	AP LAUREL MOUNTAIN 1 BT	133	DAY FAYETTE 1 SP	188	JC WOODBRIDGE 2 CC	243	PS KEARNY 131 CT	298	VP PECAN 1 SP
24	AEP HARDIN 12 SP	79	AP LAUREL MOUNTAIN 1 WF	134	DAY HIGHLAND COUNTY 1 SP	189	ME ADAMS 1 SP	244	PS KEARNY 132 CT	299	VP PINE GLADE 1 SP
25	AEP HARDIN 23 SP	80	AP LEGORE BRIDGE 1 SP	135	DAY HIGHLAND COUNTY 2 SP	190	ME BIRDSBORO 1 CC	245	PS KEARNY 133 CT	300	VP PINEY CREEK 1 SP
26	AEP HARDIN 34 SP	81	AP MARLOWE 1 SP	136	DAY HIGHLAND COUNTY 3-4 SP	191	ME COTTONTAIL 1 SP	246	PS KEARNY 134 CT	301	VP PLEASANT HILL - SUFFOLK 2 SP
27	AEP HEADWATERS 1 WF	82	AP NORTH LONGVIEW 1 F	137	DAY PICKAWAY COUNTY 1 SP	192	ME COTTONTAIL 2 SP	247	PS KEARNY 141 CT	302	VP POCATY 1 SP
28	AEP HEADWATERS 2 WF	83	AP PINNACLE 1 WF	138	DAY TAIT 8 BT	193	ME COTTONTAIL 8 SP	248	PS KEARNY 142 CT	303	VP POWELLS CREEK 1 SP
29	AEP HOG CREEK 1 WF	84	AP ROTH ROCK 1 WF	139	DEOK HILLCREST 1 SP	194	ME LYONS 1 SP	249	PS NEWARK ENERGY CENTER 10 CC	304	VP POWHATAN 2 SP
30	AEP HONEYSUCKLE 1 SP	85	AP SOUTH CHESTNUT 1 WF	140	DEOK MELDAHL DAM 1 H	195	PE DELTA 1-4 CC	250	PS SEWAREN 7 CC	305	VP PUMPKINSEED 1 SP
31	AEP INDECK NILES ENERGY CENTER 1 CC	86	AP ST THOMAS 1 SP	141	DEOK MIDDLETOWN ENERGY 1 CC	196	PE DELTA 5-7 CC	251	VP ALTON POST OFFICE 1 SP	306	VP RANCHLAND 2 SP
32	AEP LONG RIDGE ENERGY 1 CC	87	AP ST THOMAS 2 SP	142	DEOK NESTLEWOOD 1 SP	197	PEP KEYS ENERGY CENTER 1 CC	252	VP AMERICAN BEECH 1 SP	307	VP RENAN 1 SP
33	AEP MAMMOTH NORTH 1 SP	88	AP TWIN RIDGES 1 WF	143	DEOK YANKEE 1 F	198	PEP MILLS GROVE 1 SP	253	VP AULANDER HOLLOMAN 1 SP	308	VP SAPONY 1 SP
34	AEP MAPLEWOOD 1 SP	89	AP WARRIOR RUN 2 BT	144	DPL CHERRYDALE 1 SP	199	PEP ST CHARLES - KELSON RIDGE 1 CC	254	VP BEAR GARDEN	309	VP SHILLELAGH 1 SP
35	AEP MARTIN COUNTY 1 SP	90	AP WESTMORELAND 1 CC	145	DPL DEMEC - CLAYTON 2 CT	200	PEP ST CHARLES-KELSON RIDGE 1 CC	255	VP BLUESTONE FARM 1 SP	310	VP SOLIDAGO 1 SP
36	AEP MEADOW LAKE 5 WF	91	AP WILLIAMSPORT 3 SP	146	DPL DORCHESTER COUNTY 1 SP	201	PEP ST CHARLES-KELSON RIDGE 2 CC	256	VP BOOKERS MILL 1 SP	311	VP SOUTH BOSTON 1 F
37	AEP MEADOW LAKE 6 WF	92	AP WILLOW ISLAND 1 H	147	DPL EGYPT ROAD - MACELANE 1 SP	202	PL EAST CHILLI 1 SP	257	VP BRIEL FARM 1 SP	312	VP SPANISH GROVE 1 SP
38	AEP PAULDING 3 WF	93	AP WS SARISH - SMITH FRANCIS 1 SP	148	DPL GARRISON EC 1 CC	203	PL HAZEL 1 FW	258	VP BRUNSWICK 1CC	313	VP SPOTSYLVANIA 1 SP
39	AEP PAULDING 41 WF	94	BC PERRYMAN 6 CT	149	DPL GREAT BAY KINGS CREEK 1 SP	204	PL HOLTWOOD 18	259	VP BUTCHER CREEK 1 SP	314	VP SPRING GROVE 1 SP
40	AEP PAULDING 42 WF	95	COM 924 THREE RIVERS EC 1 CC	150	DPL GREAT BAY KINGS CREEK 2 SP	205	PL HOLTWOOD 19	260	VP CARVERS CREEK 1 SP	315	VP SPRING GROVE 2 SP
41	AEP POWELL CREEK - LAMMER 1 SP	96	COM 924 THREE RIVERS EC 2 CC	151	DPL JONES FARM LANE 1 SP	206	PL HUMMEL STATION 1 CC	261	VP CAVALIER 1 SP	316	VP SUMMIT FARMS 1 SP
42	AEP RIVERSTART 1 SP	97	COM 929 JACKSON 1 CC	152	DPL OAK HALL 1 SP	207	PL HUNLOCK CC	262	VP CHESTNUT 1 SP	317	VP SUNNYBROOK FARM 1 SP
43	AEP RIVERSTART 3 SP	98	COM 929 JACKSON 2 CC	153	DPL PONDTOWN 2 SP	208	PL LACKAWANNA COUNTY 1 CC	263	VP CHICKAHOMINY 1 SP	318	VP TIMBERMILL 1 WF
44	AEP ROSS COUNTY 1 SP	99	COM 942 NELSON 1 CC	154	DPL RED LION 1 FC	209	PL LACKAWANNA COUNTY 2 CC	264	VP CHICKAHOMINY 2 SP	319	VP UNION CAMP 9-10 F
45	AEP SALT CITY 1 SP	100	COM 942 NELSON 2 CC	155	DPL RICHFIELD 3 SP	210	PL LACKAWANNA COUNTY 3 CC	265	VP COLONIAL TRAIL WEST 1 SP	320	VP WARDS CREEK 1 SP
46	AEP SCIOTO RIDGE 1 WF	101	COM 942 NELSON 3 CT	156	DPL TOWNSEND 1 SP	211	PL MOXIE FREEDOM 11 CC	266	VP CONETOE 2 SP	321	VP WARREN COUNTY FRONT ROYAL CC
47	AEP ST JOSEPH ENERGY CENTER 1 CC	102	COM 942 NELSON 4 CT	157	DPL WILDCAT POINT 1 CC	212	PL MOXIE FREEDOM 21 CC	267	VP CORRECTIONAL 1 SP	322	VP WATER STRIDER 1 SP
48	AEP ST JOSEPH SOLAR PARK 1 SP	103	COM ALTA FARMS II 1 WF	158	DUQ GAUCHO 2 SP	213	PL NORTHUMBERLAND 2 SP	268	VP CRYSTAL HILL 1 SP	323	VP WATLINGTON 1 SP
49	AEP SYCAMORE CREEK 1 SP	104	COM BISHOP HILL 1 WF	159	DUQ MONACA-PENNCHEM 1 CC	214	PL PA SOLAR 2 SP	269	VP DESERT 1 WF	324	VP WAVERLY 1 SP
50	AEP TIMBER ROAD 1 SP	105	COM BISHOP HILL 2 WF	160	EKPC BLUEBIRD 1 SP	215	PL PATRIOT 1 F	270	VP DESPER 1 SP	325	VP WAVERLY 2 SP
51	AEP TIMBER2 1 WF	106	COM BLOOMING GROVE 1 WF1	161	EKPC GLOVER CREEK 1 SP	216	PL PATRIOT 2 F	271	VP DOSWELL 2 CT	326	VP WHITEHORN 1 SP
52	AEP TRADE POST 1 SP	107	COM BRIGHT STALK 1 WF	162	EKPC TURKEY CREEK 1 SP	217	PL PENN 3 SP	272	VP DOSWELL 3 CT	327	VP WILKINSON ENERGY CENTER 1 SP
53	AEP TRISHE 1 WF	108	COM GRAND RIDGE 7 BT	163	FE ARCHE ENERGY 1 SP	218	PL SWIFTWATER 1 SP	273	VP DRY BREAD 1 SP	328	VP WINTERBERRY 1 SP
54	AEP UNION 1 SP	109	COM GREEN RIVER 1 WF	164	FE BIG PLAIN 2 SP	219	PL WALKER 1 SP	274	VP DRY BRIDGE EC 1 BT		
55	AEP UNION RIDGE 1 SP	110	COM GREEN RIVER 2 WF	165	FE FREMONT 1 SCCT	220	PN ASPEN ROAD 1 SP	275	VP DULLES 1-2 SP		

Generation Retirements[46] [47] [48]

Generating units generally plan to retire when they are not economic and do not expect to be economic. Generating units may also plan to retire if environmental restrictions make it too costly to comply or impossible to comply. The MMU performs an analysis of the economics of all units that plan to retire in order to verify that the units are not economic and there is no potential exercise of market power through physical withholding that could advantage the owner's portfolio.[49] The definition of economic is that unit net revenues are greater than or equal to the unit's avoidable or going forward costs.

PJM does not have the authority to order generating plants to continue operating. PJM's responsibility is to ensure system reliability. When a unit retirement creates reliability issues based on existing and planned generation facilities and on existing and planned transmission facilities, PJM identifies transmission solutions. The U. S. Department of Energy does have the authority to temporarily order generating plants to continue operating under section 202(c) of the Federal Power Act in the event of emergency or reliability issues.[50]

Rules that preserve ownership of the Capacity Interconnection Rights (CIRs) associated with retired units, and with the conversion from Capacity Performance (CP) to energy only status, impose significant costs on new entrants. Currently, CIRs persist for one year if unused, and that period can be further extended, at no cost, if the CIRs are assigned to a new project in the interconnection queue at the same point of interconnection.[51] There are currently no rules governing the retention of CIRs when units want to convert to energy only status or require time to upgrade to retain CP status. The rules governing conversion or upgrades should be the same as the rules governing retired units. Reforms that require the holders of CIRs to use or lose them, and that terminate CIRs on the date of retirement, would make new entry appropriately more attractive. There is no good economic and policy rationale for extending ownership rights to CIRs for inactive units. Incumbent providers receive a significant advantage simply by imposing on new entrants the entire cost of system upgrades needed to accommodate new entrants. In May 2012, PJM stakeholders (through the Interconnection Process Senior Task Force (IPSTF)) modified the rules to reduce the length of time for which CIRs are retained by the current owner after unit retirements from three years to one.[52] The MMU recognized the progress made in this rule change, but it did not fully address the issues. Even if the policy treatment of such CIRs remains unchanged, the rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors or to exercise market power by requiring high payments for CIRs. 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.

Replacement Generation Interconnection Service Requests

On January 31, 2025, PJM proposed revisions to the tariff to revise the existing process for transferring CIRs from deactivating generation resources to Replacement Generation Resources.[53] Under the proposed revisions, replacement generation resources are required to have a commercial operation date that is the later of three years after the actual deactivation date of the deactivating generating facility, or the date that the replacement generation project developer executes a GIA (or requests that the GIA be filed unexecuted).[54] The package included three exceptions to the commercial operation date requirements. First, generation resources with industry recognized significant construction timelines are permitted to have a commercial operation date beyond three years. Second, the proposed revisions provides generation resources with a one time option to extend their commercial operation date beyond three years for any cause. Finally, the proposed revisions allow project developers to use the unilateral, one year milestone extension found in the pro forma GIA.

46 See PJM. Planning. "Generator Deactivations," (Accessed on March 31, 2026) <https://www.pjm.com/planning/service-requests/gen-deactivations>.
47 Generation retirements reported in this section do not include external units. Therefore, retirement totals reported in this section may not match totals reported elsewhere in this report where external units are included.
48 For additional information on canceled unit retirement requests, see *2026 Quarterly State of the Market Report for PJM: January through March*, Section 5: Capacity, "Timing of Unit Retirements".
49 See OATT Part V and Attachment M–Appendix § IV.
50 See 16 U.S.C. § 824a(c).
51 See OATT § 230.3.3.
52 See PJM Interconnection, L.L.C., Docket No. ER12-1177 (Feb. 29, 2012).
53 See PJM Interconnection, L.L.C., Docket No. ER25-1128 (January 31, 2025).
54 Id. at 7.

On August 8, 2025, the Commission issued its order rejecting PJM's proposed Tariff revisions.[55] The Commission found that the proposed one-time option for a replacement generation project developer to extend a project's commercial operation date without a maximum time limit for the extension rendered PJM's proposal unjust and unreasonable.

On October 31, 2025, PJM filed a revised replacement generation interconnection service process that addressed the concerns raised by the Commission.[56]

The MMU submitted comments in opposition to the proposed process.[57] The proposed process creates delays by permitting retiring generators to delay the transfer of CIRs for up to a full year for the sole purpose of maximizing the profits from selling the CIRs or gaining a special advantage in jumping the interconnection queue. Retiring generators do not have property rights in the CIRs which depend on the entire transmission grid for their value. The CIR transfer process does nothing to enhance efficiency or the timely replacement of retiring generation resources. The basic purpose of the process is to permit existing generators to sell their CIRs to the highest bidder rather than to identify the best replacement resource. The proposal is inconsistent with open access and the purpose of CIRs. A process that truly reforms CIRs would terminate CIRs immediately at the time a resource deactivates, and thereby avoid undue discrimination, promote competition and facilitate the rapid entry of needed new generation.

On January 29, 2026, the Commission approved the revised tariff revisions to establish the replacement generation interconnection service process.[58]

Generation Retirements 2011 through 2030

Table 12-6 shows that as of March 31, 2026, there were 64,202.9 MW of generation that have been, or are planned to be, retired from 2011 through 2030, of which 46,526.8 MW (72.5 percent) are coal fired steam units. Retirements are primarily a result of the inability of coal and other units to compete with efficient combined cycle units burning low cost gas.

55 192 FERC ¶ 61,137 (2025)
56 See PJM Interconnection, L.L.C., Docket No. ER26-403 (October 31, 2025).
57 See IMM Comments. *PJM Interconnection L.LC.* Docket No. ER26-403.
58 194 FERC ¶ 61,079 (2026).

Table 12-6 Summary of unit retirements by unit type (MW): 2011 through 2030

	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
Retirements 2011	0.0	0.0	0.0	128.3	0.0	0.0	0.0	0.0	0.0	0.0	2.7	0.0	0.0	0.0	0.0	543.0	522.5	0.0	0.0	0.0	0.0	1,196.5
Retirements 2012	0.0	0.0	250.0	240.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,907.9	0.0	548.0	16.0	0.0	0.0	6,961.9
Retirements 2013	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.9	7.0	0.0	0.0	0.0	2,589.9	82.0	166.0	8.0	0.0	0.0	2,858.8
Retirements 2014	0.0	0.0	136.0	422.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15.3	0.0	0.0	0.0	2,239.0	158.0	0.0	0.0	0.0	0.0	2,970.3
Retirements 2015	0.0	0.0	1,319.0	856.2	2.0	0.0	0.0	0.0	0.0	0.0	10.3	0.0	0.0	0.0	0.0	7,064.8	0.0	0.0	0.0	10.4	0.0	9,262.7
Retirements 2016	0.0	0.0	0.0	65.0	6.0	0.0	0.5	0.0	0.0	0.0	8.0	3.9	0.0	0.0	0.0	243.0	74.0	0.0	0.0	0.0	0.0	400.4
Retirements 2017	40.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.0	0.0	0.0	2,038.0	34.0	0.0	0.0	0.0	0.0	2,112.8
Retirements 2018	1.0	425.0	0.0	38.0	1.6	0.0	0.0	0.0	614.5	0.0	17.2	6.9	0.0	0.0	0.0	3,166.5	1,016.0	148.0	108.0	0.0	0.0	5,542.7
Retirements 2019	0.0	0.0	346.8	51.4	6.4	0.0	0.0	0.0	805.0	0.0	0.0	15.9	0.0	0.0	0.0	4,110.5	100.3	10.0	10.0	0.0	0.0	5,456.3
Retirements 2020	0.0	0.0	232.5	24.0	6.0	0.0	0.0	0.0	0.0	0.0	0.0	14.7	0.0	0.0	0.0	2,131.8	0.0	786.0	60.0	0.0	0.0	3,255.0
Retirements 2021	4.0	118.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15.9	0.0	0.0	0.0	1,020.4	102.0	0.0	50.0	0.0	0.0	1,310.3
Retirements 2022	41.0	240.5	99.0	360.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	36.6	0.0	0.0	0.0	5,385.0	0.0	0.0	0.0	0.0	0.0	6,162.4
Retirements 2023	0.0	114.0	52.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	36.0	19.2	0.0	0.0	0.0	4,380.0	1,326.0	800.0	0.0	0.0	0.0	6,727.8
Retirements 2024	28.5	0.0	149.2	108.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.7	0.0	0.0	0.0	180.0	0.0	0.0	50.0	0.0	0.0	527.4
Retirements 2025	33.4	16.5	380.0	12.9	0.0	0.0	0.0	0.0	0.0	0.0	4.0	15.0	2.5	0.0	0.0	410.0	126.0	0.0	0.0	0.0	0.0	1,000.3
Retirements 2026	2.0	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	2.0
Planned Retirements (April 1, 2026 and later)	89.9	0.0	1,768.0	16.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.0	0.0	0.0	0.0	5,117.0	760.0	702.0	0.0	0.0	0.0	8,455.3
Total	239.8	914.0	4,733.1	2,322.5	22.0	0.0	0.5	0.0	1,419.5	0.0	84.1	164.9	2.5	0.0	0.0	46,526.8	4,300.8	3,160.0	302.0	10.4	0.0	64,202.9

Table 12-7 shows the capacity, average size, and average age of units retiring in PJM, from 2011 through 2030, while Table 12-8 shows these retirements by state. Of the 64,202.9 MW of units that has been, or are planned to be, retired from 2011 through 2030, 46,526.8 MW (72.5 percent) are coal fired steam units. These coal fired steam units have an average age of 52.2 years and an average size of 238.6 MW. Over half of the retiring coal fired steam units, 51.1 percent, are located in Ohio or Pennsylvania.

Table 12-7 Retirements by unit type: 2011 through 2030

Unit Type	Number of Units	Avg. Size (MW)	Avg. Age at Retirement (Years)	Total MW	Percent
Battery	19	12.6	9.7	239.8	0.4%
Combined Cycle	8	114.3	27.0	914.0	1.4%
Combustion Turbine	160	31.0	35.2	7,077.6	11.0%
Natural Gas	85	55.7	39.4	4,733.1	7.4%
Oil	69	33.7	47.0	2,322.5	3.6%
Other	6	3.7	19.2	22.0	0.0%
Fuel Cell	0	0.0	0.0	0.0	0.0%
Hydro	1	0.5	113.8	0.5	0.0%
Pumped Storage	1	0.5	113.8	0.5	0.0%
Run of River	0	0.0	0.0	0.0	0.0%
Nuclear	2	709.8	47.2	1,419.5	2.2%
RICE	48	5.1	26.9	249.0	0.4%
Natural Gas	0	0.0	0.0	0.0	0.0%
Oil	18	4.7	40.3	84.1	0.1%
Other	30	5.5	13.4	164.9	0.3%
Solar	0	0.0	0.0	0.0	0.0%
Solar + Storage	0	0.0	0.0	0.0	0.0%
Solar + Wind	0	0.0	0.0	0.0	0.0%
Steam	239	197.2	46.1	54,289.6	84.6%
Coal	195	238.6	52.2	46,526.8	72.5%
Natural Gas	26	165.4	57.9	4,300.8	6.7%
Oil	9	351.1	49.1	3,160.0	4.9%
Other	9	33.6	25.3	302.0	0.5%
Wind	1	10.4	15.6	10.4	0.0%
Wind + Storage	0	0.0	0.0	0.0	0.0%
Total	479	134.0	43.5	64,202.9	100.0%

Table 12-8 Retirements (MW) by unit type and state: 2011 through 2030

State	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
DC	0.0	0.0	0.0	240.0	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	548.0	0.0	0.0	0.0	788.0
DE	0.0	0.0	0.0	16.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	664.0	136.0	0.0	0.0	0.0	0.0	816.4
IL	81.5	0.0	2,123.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	35.7	0.0	0.0	0.0	3,926.1	1,326.0	0.0	0.0	0.0	0.0	7,493.2
IN	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	3,602.0	0.0	0.0	0.0	0.0	0.0	3,602.0
KY	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	1,111.0	0.0	0.0	0.0	0.0	0.0	1,111.0
MD	20.0	0.0	347.5	274.9	1.6	0.0	0.0	0.0	0.0	0.0	2.0	3.2	0.0	0.0	0.0	4,521.0	297.0	702.0	0.0	0.0	0.0	6,169.2
NC	0.0	0.0	0.0	31.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	324.5	0.0	0.0	0.0	0.0	0.0	355.5
NJ	2.0	579.5	2,060.3	1,066.2	6.4	0.0	0.5	0.0	614.5	0.0	8.0	36.6	2.5	0.0	0.0	2,001.9	932.5	148.0	10.0	0.0	0.0	7,468.9
OH	64.0	16.5	0.0	307.0	0.0	0.0	0.0	0.0	0.0	0.0	34.3	46.7	0.0	0.0	0.0	16,607.4	0.0	0.0	0.0	0.0	0.0	17,075.9
PA	11.4	51.0	121.4	307.3	14.0	0.0	0.0	0.0	805.0	0.0	15.9	20.5	0.0	0.0	0.0	7,180.0	1,046.3	176.0	109.0	10.4	0.0	9,868.2
TN	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	50.0	0.0	0.0	50.0
VA	0.0	267.0	80.0	79.7	0.0	0.0	0.0	0.0	0.0	0.0	23.9	22.1	0.0	0.0	0.0	3,897.9	563.0	1,586.0	133.0	0.0	0.0	6,652.6
WV	60.9	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	2,691.0	0.0	0.0	0.0	0.0	0.0	2,751.9
Total	239.8	914.0	4,733.1	2,322.5	22.0	0.0	0.5	0.0	1,419.5	0.0	84.1	164.9	2.5	0.0	0.0	46,526.8	4,300.8	3,160.0	302.0	10.4	0.0	64,202.9

Figure 12-4 is a map of unit retirements from 2011 through 2030, with a mapping to unit names in Table 12-9.

Figure 12-4 Map of unit retirements: 2011 through 2030

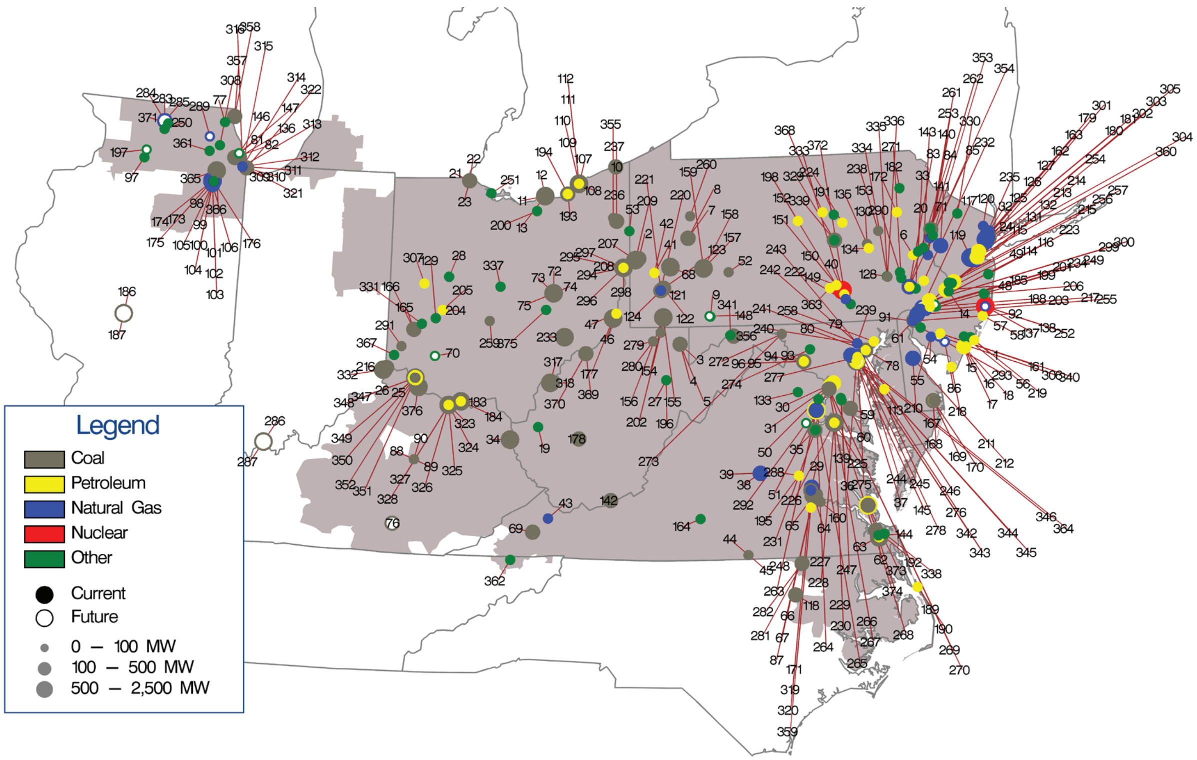


Table 12-9 Unit identification for map of unit retirements: 2011 through 2030

ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit
1	AC Landfill Units 1 and 2	61	Chambers CCLP	121	Elrama 1	181	Kearny 9	241	Notch Cliff GT3	301	Sewaren 1	361	West Chicago Energy Storage
2	AES Beaver Valley	62	Chesapeake 1-4	122	Elrama 2	182	Keystone Recovery (Units 1 - 7)	242	Notch Cliff GT4	302	Sewaren 2	362	West Kingsport LF
3	Albright 1	63	Chesapeake 7-10	123	Elrama 3	183	Killen 2	243	Notch Cliff GT5	303	Sewaren 3	363	West Shore CT 1-2
4	Albright 2	64	Chesterfield 3	124	Elrama 4	184	Killen CT	244	Notch Cliff GT6	304	Sewaren 4	364	Westport 5
5	Albright 3	65	Chesterfield 4	125	Essex 10-11	185	Kimberly Clark Generator	245	Notch Cliff GT7	305	Sewaren 6	365	Will County 3
6	Allentown CT 1-4	66	Chesterfield 5	126	Essex 12	186	Kincaid Unit 1	246	Notch Cliff GT8	306	Sherman Avenue CT1	366	Will County 4
7	Armstrong 1	67	Chesterfield 6	127	Essex 9	187	Kincaid Unit 2	247	Oaks Landfill	307	Sidney Unit 5	367	Willey Energy Storage
8	Armstrong 2	68	Cheswick 1	128	Evergreen Power United Corstack	188	Kinsley Landfill	248	Occoquan 1 LF	308	Solberg 1 BT	368	Williamsport-Lycoming CT 1-2
9	Arnold (Green Mtn.) Wind Farm	69	Clinch River 3	129	FE DOVETAIL 1 CT	189	Kitty Hawk GT 1	249	Ocean County LF	309	Southeast Chicago CT11	369	Willow Island 1
10	Ashtabula 5	70	Clinton Battery	130	FRACKVILLE WHEELABRATOR 1	190	Kitty Hawk GT 2	250	Orchard Hills LF	310	Southeast Chicago CT12	370	Willow Island 2
11	Avon Lake 10	71	Columbia Dam Hydro	131	Fairless Hills Landfill A	191	Koppers Co. IPP	251	Ottawa County Project	311	Southeast Chicago CT5	371	Winnebago Landfill
12	Avon Lake 7	72	Conesville 3	132	Fairless Hills Landfill B	192	Lake Kingman	252	Oyster Creek	312	Southeast Chicago CT6	372	York Generation Facility
13	Avon Lake 9	73	Conesville 4	133	Fauquier County Landfill	193	Lake Shore 18	253	PL MARTINS CREEK 1-4 CT	313	Southeast Chicago CT7	373	Yorktown 1-2
14	BC Landfill	74	Conesville 5	134	Fishbach CT 1	194	Lake Shore EMD	254	Parlin NUG	314	Southeast Chicago CT8	374	Yorktown 3
15	BL England 1	75	Conesville 6	135	Fishbach CT 2	195	Lanier 1 CT	255	Pedricktown Cogen CC	315	Southeast Chicago GT10	375	Zanesville Landfill
16	BL England 2	76	Cooper 1	136	Fisk Street 19	196	Laurel Mountain Battery	256	Pennsbury Generator Landfill 1	316	Southeast Chicago GT9	376	Zimmer 1
17	BL England 3	77	Countryside Landfill	137	Forked River Unit 1	197	Lee DeKalb 3 BT	257	Pennsbury Generator Landfill 2	317	Sporn 1-4		
18	BL England Diesel Units 1-4	78	Crane 1	138	Forked River Unit 2	198	Lock Haven CT 1	258	Perryman 2	318	Sporn 5		
19	Balls Gap Battery Facility	79	Crane 2	139	GUDE Landfill	199	Logan	259	Picway 5	319	Spruance NUG1 (Rich 1-2)		
20	Barbados AES Battery	80	Crane GT1	140	Gilbert 1-4	200	Lorain 1 LF	260	Piney Creek NUG	320	Spruance NUG2 (Rich 3-4)		
21	Bay Shore 2	81	Crawford 7	141	Glen Gardner 1-8	201	MANTUA CREEK 7 BT	261	Portland 1	321	State Line 3		
22	Bay Shore 3	82	Crawford 8	142	Glen Lyn 5-6	202	MEA NUG (WVU)	262	Portland 2	322	State Line 4		
23	Bay Shore 4	83	Cromby 1	143	Glendon LF	203	MH50 Markus Hook Co-gen	263	Possum Point 3	323	Stuart 1		
24	Bayonne Cogen Plant (CC)	84	Cromby 2	144	Gosport 1 F	204	Mad River CTs A	264	Possum Point 4	324	Stuart 2		
25	Beckjord Battery Unit 2	85	Cromby D	145	Gould Street Generation Station	205	Mad River CTs B	265	Possum Point 5	325	Stuart 3		
26	Beckjord Storage Unit 1	86	Cumberland CT 1	146	Grand Ridge Energy IV battery component	206	Manchester 1 LF	266	Potomac River 1	326	Stuart 4		
27	Beech Ridge Energy Storage	87	DINWIDDIE 1 CT	147	Grand Ridge Energy Storage	207	Mansfield 1	267	Potomac River 2	327	Stuart Diesels 1-4		
28	Bellefontaine Landfill Generating Station	88	Dale 1-2	148	Green Mountain Energy Storage	208	Mansfield 2	268	Potomac River 3	328	Stuart Diesels 1-4		
29	Bellemeade	89	Dale 3	149	Harrisburg 4 CT	209	Mansfield 3	269	Potomac River 4	329	Sunbury 1-4		
30	Benning 15	90	Dale 4	150	Harrisburg CT 1	210	McKee 1	270	Potomac River 5	330	Sussex County LF		
31	Benning 16	91	Deepwater 1	151	Harrisburg CT 2	211	McKee 2	271	Pottstown LF (Moser)	331	Tait Battery		
32	Bergen 3	92	Deepwater 6	152	Harrisburg CT 3	212	McKee 3	272	R Paul Smith 3	332	Tanners Creek 1-4		
33	Bethlehem Renewable Energy Generator (Landfill)	93	Dickerson CT1	153	Harwood 1-2	213	Mercer 1	273	R Paul Smith 4	333	Three Mile Island Unit 1		
34	Big Sandy 2	94	Dickerson Unit 1	154	Hatfield's Ferry 1	214	Mercer 2	274	Reichs Ford Road Landfill Generator	334	Titus 1		
35	Birchwood Plant	95	Dickerson Unit 2	155	Hatfield's Ferry 2	215	Mercer 3	275	Riverside 4	335	Titus 2		
36	Brandon Shores 1	96	Dickerson Unit 3	156	Hatfield's Ferry 3	216	Miami Fort 6	276	Riverside 6	336	Titus 3		
37	Brandon Shores 2	97	Dixon Lee Landfill Generator	157	Homer City 1	217	Mickleton CT1	277	Riverside 7	337	Trent Battery Storage		
38	Bremo 3	98	ELWOOD CT 1	158	Homer City 2	218	Middle 1-3	278	Riverside 8	338	VP Virginia Beach		
39	Bremo 4	99	ELWOOD CT 2	159	Homer City 3	219	Missouri Ave B,C,D	279	Riversville 5	339	Viking Energy NUG		
40	Brunner Island Diesels	100	ELWOOD CT 3	160	Hopewell James River Cogeneration	220	Mitchell 2	280	Riversville 6	340	Vineland West CT		
41	Brunot Island 1B	101	ELWOOD CT 4	161	Howard Down 10	221	Mitchell 3	281	Roanoke Valley 1	341	WARRIOR RUN 2 BT		
42	Brunot Island 1C	102	ELWOOD CT 5	162	Hudson 1	222	Modern Power Landfill NUG	282	Roanoke Valley 2	342	Wagner 1		
43	Buchanan Units 1 and 2	103	ELWOOD CT 6	163	Hudson 2	223	Monmouth NUG landfill	283	Rockford CT11	343	Wagner 2		
44	Buggs Island 1 (Mecklenberg)	104	ELWOOD CT 7	164	Hurt NUG	224	Montour ATG	284	Rockford CT12	344	Wagner 3		
45	Buggs Island 2 (Mecklenberg)	105	ELWOOD CT 8	165	Hutchings 1-3, 5-6	225	Morgantown CT 5	285	Rockford CT21	345	Wagner 4		
46	Burger 3	106	ELWOOD CT 9	166	Hutchings 4	226	Morgantown CT 6	286	Rockport Unit 1	346	Wagner CT 1		
47	Burger EMD	107	Eastlake 1	167	Indian River CT10	227	Morgantown CT1	287	Rockport Unit 2	347	Walter C Beckjord 1		
48	Burlington 8,11	108	Eastlake 2	168	Indian River 1	228	Morgantown CT2	288	Rockville CT	348	Walter C Beckjord 2		
49	Burlington 9	109	Eastlake 3	169	Indian River 3	229	Morgantown Unit 1	289	Rocky Road CT 33	349	Walter C Beckjord 3		
50	Buzzard Point East Banks 1,2,4-8	110	Eastlake 4	170	Indian River 4	230	Morgantown Unit 2	290	Rolling Hills Landfill Generator	350	Walter C Beckjord 4		
51	Buzzard Point West Banks 1-9	111	Eastlake 5	171	Ingenco Petersburg	231	Morris Landfill Generator	291	SMART Paper	351	Walter C Beckjord 5-6		
52	Cambria CoGen	112	Eastlake 6	172	Jenkins CT 1-2	232	Morris Road 1 D	292	STAFFORD 1 LF	352	Walter C Beckjord GT 1-4		
53	Carbon Limestone LF	113	Easton Diesel Unit 8	173	Joliet 6	233	Muskingum River 1-5	293	Salem County LF	353	Warren County Landfill		
54	Carlls Corner CT1	114	Eddystone 1	174	Joliet 7	234	National Park 1	294	Sammis 1-4	354	Warren County NUG		
55	Carlls Corner CT2	115	Eddystone 2	175	Joliet 8	235	New Bay Cogen CC	295	Sammis Diesel Units	355	Warren Evergreen CT1		
56	Cates Road Solar	116	Eddystone Unit 3	176	Joliet Energy Storage	236	Niles 1	296	Sammis Unit 5	356	Warrior Run		
57	Cedar 1	117	Eddystone Unit 4	177	Kammer 1-3	237	Niles 2	297	Sammis Unit 6	357	Waukegan 7		
58	Cedar 2	118	Edgecomb NUG (Rocky 1-2)	178	Kanawha River 1-2	238	Northeastern Power NEPCO	298	Sammis Unit 7	358	Waukegan 8		
59	Chalk Point Unit 1	119	Edison 1-3	179	Kearny 10	239	Notch Cliff GT1	299	Schuylkill 1	359	Weakley CT		
60	Chalk Point Unit 2	120	Elmwood Park Power	180	Kearny 11	240	Notch Cliff GT2	300	Schuylkill Diesel	360	Werner 1-4		

Current Year Generation Retirements

Table 12-10 shows that in the first three months of 2026, 2.0 MW of generation retired. The largest generator that retired in the first three months of 2026 was the 2.0 MW Beckjord Storage Unit 1 battery unit located in the DUKE Zone. Of the 2.0 MW of generation that retired in the first three months of 2026, 2.0 MW (100.0 percent) were located in the DUKE Zone.

Table 12-10 Unit deactivations: January through March, 2026

Owner	Unit Name	ICAP (MW)	Unit Type	Zone Name	Age (Years)	Retirement Date
Galt Power Inc.	Beckjord Storage Unit 1	2.0	Battery	DUKE	11	05-Mar-26
Total		2.0				

Planned Generation Retirements

Table 12-11 shows that, as of March 31, 2026, there were 8,455.3 MW of generation that have requested retirement after March 31, 2026. Of the 8,455.3 MW requesting retirement, 5,117.0 MW (60.5 percent) are coal fired steam units. Of the 8,455.3 MW of planned retirements, 2,671.9 MW (31.6 percent) are located in the COMED Zone. Of the generation requesting retirement in the COMED Zone, 1,527.9 MW (57.2 percent) are CT Natural Gas units.

Table 12-11 Planned retirement of units: March 31, 2026

Owner	Unit Name	ICAP (MW)	Unit Type	Zone Name	Projected Deactivation Date
Constellation Energy Generation, LLC	Eddystone Unit 3	380.0	Steam-Natural Gas	PECO	24-May-26
Constellation Energy Generation, LLC	Eddystone Unit 4	380.0	Steam-Natural Gas	PECO	24-May-26
Hull Street Energy LLC	ELWOOD CT 1	150.0	CT-Natural Gas	COMED	01-Jun-26
Hull Street Energy LLC	ELWOOD CT 2	150.0	CT-Natural Gas	COMED	01-Jun-26
Hull Street Energy LLC	ELWOOD CT 3	150.0	CT-Natural Gas	COMED	01-Jun-26
Hull Street Energy LLC	ELWOOD CT 4	150.0	CT-Natural Gas	COMED	01-Jun-26
Dairyland Power Cooperative	ELWOOD CT 5	150.0	CT-Natural Gas	COMED	01-Jun-26
Dairyland Power Cooperative	ELWOOD CT 6	150.0	CT-Natural Gas	COMED	01-Jun-26
Dairyland Power Cooperative	ELWOOD CT 7	150.0	CT-Natural Gas	COMED	01-Jun-26
Hull Street Energy LLC	Forked River Unit 1	34.0	CT-Natural Gas	JCPLC	01-Jun-26
Hull Street Energy LLC	Forked River Unit 2	31.0	CT-Natural Gas	JCPLC	01-Jun-26
NRG Energy Inc	Indian River CT10	16.4	CT-Oil	DPL	01-Jun-26
Constellation Energy Generation, LLC	Clinton Battery	10.0	Battery	DUKE	01-Jan-27
Invenergy LLC	Beech Ridge Energy Storage	31.5	Battery	APS	01-Apr-27
Invenergy LLC	Grand Ridge Energy Storage	4.5	Battery	COMED	01-Apr-27
NextEra Energy, Inc.	Green Mountain Energy Storage	10.4	Battery	PE	01-Apr-27
NextEra Energy, Inc.	Lee DeKalb 3 BT	31.5	Battery	COMED	01-Apr-27
NextEra Energy, Inc.	MANTUA CREEK 7 BT	2.0	Battery	PSEG	01-Apr-27
Dairyland Power Cooperative	Rocky Road CT 33	28.0	CT-Natural Gas	COMED	01-Apr-27
Truelight, LLC	STAFFORD 1 LF	2.0	RICE-Other	DOM	01-Apr-27
Constellation Energy Generation, LLC	Cumberland CT 1	90.8	CT-Natural Gas	ACEC	01-Jun-27
Constellation Energy Generation, LLC	Sherman Avenue CT1	84.3	CT-Natural Gas	ACEC	01-Jun-27
Vistra Energy Corp	Kincaid Unit 1	554.0	Steam-Coal	COMED	30-Nov-27
Vistra Energy Corp	Kincaid Unit 2	554.0	Steam-Coal	COMED	30-Nov-27
American Electric Power Company, Inc.	Rockport Unit 1	1,320.0	Steam-Coal	AEP	31-Dec-28
American Electric Power Company, Inc.	Rockport Unit 2	1,300.0	Steam-Coal	AEP	31-Dec-28
Talen Energy Corporation	Brandon Shores 1	635.0	Steam-Coal	BGE	31-May-29
Talen Energy Corporation	Brandon Shores 2	638.0	Steam-Coal	BGE	31-May-29
Talen Energy Corporation	Wagner 3	305.0	Steam-Oil	BGE	31-May-29
Talen Energy Corporation	Wagner 4	397.0	Steam-Oil	BGE	31-May-29
NRG Energy Inc	Rockford CT11	149.1	CT-Natural Gas	COMED	31-Dec-29
NRG Energy Inc	Rockford CT12	147.8	CT-Natural Gas	COMED	31-Dec-29
NRG Energy Inc	Rockford CT21	153.0	CT-Natural Gas	COMED	31-Dec-29
East Kentucky Power Cooperative, Inc	Cooper 1	116.0	Steam-Coal	EKPC	31-Dec-30

In addition to the 8,455.3 MW of announced unit retirements as of March 31, 2026, there are significantly more unit retirements expected as a result of environmental regulations and for economic reasons.[59]

Generation Queue[60]

Any entity that requests interconnection of a new generating facility, including increases to the capacity of an existing generating unit, or that requests interconnection of a merchant transmission facility, must follow the process defined in the PJM tariff to obtain interconnection service.[61] PJM's process is designed to ensure that new generation is added in a reliable and systematic manner. The process is complex and time consuming at least in part as a result of the required analyses. The cost, time and uncertainty associated with interconnecting to the grid may create barriers to entry for potential entrants. But the behavior of project developers also creates issues with queue management and exacerbates the barriers.

Generation request queues are groups of proposed projects, including new units, reratings of existing units, capacity resources and energy only resources. Each queue is open for a fixed amount of time. Studies commence on all projects in a given queue when that queue closes. Projects submitted to the queue undergo a deficiency review to ensure that all required information is provided. A queue position is assigned once the project has met the submission requirements. Projects that do not meet submission requirements are removed from the queue.

In 2022, after a lengthy stakeholder process (Interconnection Process Reform Task Force (IPRTF)) PJM filed significant changes to improve overall queue management. On November 29, 2022, the Commission issued an order accepting PJM's tariff revisions modifying how PJM manages the new services queue.[62] The new queue process includes modifications to implement a cluster/cycle based processing method to replace the first in/first out processing method.[63] 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 new cycle process also includes defining progress to completion through three phases, with a customer decision at the end of each. The new cycle process requires a stronger definition of site control, and includes readiness deposits (some of which are nonrefundable) based on the phase of development. Additional process modifications include limits to technology changes, improvements to the application review phase, removal of optional interconnection study processes, modifications to the study schedules to reduce the number of restudies required in the event of project modifications, adjusting the queue window schedule to coincide with the previous clusters' milestones, and modifications to cost responsibility by assigning responsibility to all projects within a queue cycle. The new cycle 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.

The transition to the new cycle process began on July 10, 2023. The last open series queue prior to July 10, 2023, was AJ1. The new cycle process includes a transition which treats projects based on their series queue status. All projects through series queue window AD2 will continue as part of the series queue process. The transition process assigned series queue projects in queue windows AE1 through AH1 to transition cycle 1 (TC1) and transition cycle 2 (TC2) and also provides for the expedited treatment (fast track) of projects submitted in the AE1 through AG1 queue windows with upgrade costs less than $5 million. The start of the transition to the new cycle process on July 10, 2023, also started the 60 day readiness review period for active projects in the AE1 through AG1 queues. During this time, project developers provided evidence of site control and provided the necessary readiness deposit.[64] Those projects in the AE1 through AG1 series queues that had not yet received an interconnection service agreement or a wholesale market power agreement

59 For more information, see *2026 Quarterly State of the Market Report for PJM: January through March*, Section 7: Net Revenue.
60 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.
61 See OATT Parts IV & VI.
62 181 FERC ¶ 61,162 (2022).
63 See "Interconnection Process Reform," presented at April 27, 2022 Members Committee meeting. <https://www.pjm.com/-/media/committees-groups/committees/mc/2022/20220427/20220427-item-01a-1-interconnection-process-reform-presentation.ashx>.
64 See "PJM Manual 14H: New Service Requests Cycle Process," Rev. 03 (September 25, 2025) for a complete list of all readiness requirements.

and also met readiness requirements were reviewed to determine if they were eligible for the fast track process, or if they would be studied as part of transition cycle 1. Of the 734 projects in queues AE1 through AG1 reviewed, 306 projects (41.7 percent) qualified for the expedited process, 312 projects (42.5 percent) were assigned to transition cycle 1 and 116 projects (15.8 percent) were withdrawn from the queue.

The transition process must also account for the fact that PJM significantly underestimated the level of CIRs required for intermittent resources. PJM had required only CIRs equal to the ELCC rating of intermittent resources when in fact those resources required CIRs equal to the maximum output that contributed to the ELCC rating. In general, CIRs were understated by the difference between the ELCC derating factor and the maximum facility output of the intermittent resource. PJM filed revised rules and FERC approved them.[65] PJM has created a process to permit such resources to increase their CIRs to the required level through appropriate investments in interconnection facilities. This process will occur coincident with the start of the new service request Cycle 1.

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 a 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.[66]

New Service Requests Serial Process

Interconnection Process Studies and Agreements[67]

Prior to implementation of the new cycle process, PJM used a serial service process. In the study stage of the interconnection planning serial process, a series of studies were performed to determine the feasibility, impact, and cost of projects in the queue. Table 12-12 is an overview of the studies PJM performed in the study stage of the interconnection serial process. System impact and facilities studies were often redone when a project was withdrawn in order to determine the impact on the projects remaining in the queue.

65 183 FERC ¶61,009.
66 Once implemented, the approved solutions from PJM's Interconnection Process Reform Task Force (IPRTF) should result in improvements in these areas.
67 See "PJM Manual 14A: New Services Request Process," Rev. 30 (July 26, 2023) for a complete explanation of the interconnection process studies and agreements.

Table 12-12 Interconnection planning serial process: study stage

Study	Purpose
Feasibility Study	The feasibility study determines preliminary estimates of the type, scope, cost and lead time for construction of facilities required to interconnect the project.
System Impact Study	The system impact study is a comprehensive regional analysis of the impact of adding the new generation and/or transmission facility to the system. The study identifies the system constraints related to the project and the necessary attachment facilities, local upgrades, and network upgrades. The study refines and more comprehensively estimates cost responsibility and construction lead times for facilities and upgrades.
Facilities Study	In the facilities study, stability analysis is performed and the system impact study results are modified as necessary to reflect changes in the characteristics of other projects in the queue.

In addition to the feasibility, system impact and facilities studies, PJM would also perform additional studies under certain circumstances. These studies included the affected systems study, interim deliverability study and the long term firm transmission studies. Table 12-13 is an overview of the additional studies PJM could have performed.

Table 12-13 Interconnection planning serial process: study stage – additional studies

Study	Purpose
Affected System Study	PJM and its neighboring balancing authorities conduct interconnection studies to determine the impacts of interconnection requests on the neighboring transmission system.
Interim Deliverability Studies	Interim deliverability studies are conducted on a periodic basis in support of RPM auctions and other interconnection studies to determine if a new facility may come on line prior to its scheduled date. These studies evaluate the available system capability and provide the customer(s) with the availability of service by planning year. Interim deliverability studies use the same criteria used for the evaluation of the need for reinforcements associated with a project under study.
Long Term Firm Transmission Studies	Transmission service requests that extend beyond the available transfer capability horizon of 18 months are evaluated along with the other requests for service in the PJM new services queue to ensure deliverability. Long term firm transmission studies follow the same feasibility, system impact and facilities study process as new generation.

After the completion of a facility study, the project would enter the construction stage of the interconnection process. The final agreements required depended on the type of project. These agreements included a Construction Service Agreement (CSA), Interconnection Service Agreement (ISA), Upgrade Construction Service Agreement (UCSA), Wholesale Market Participant Agreement (WMPA) or Transmission Service Agreement (TSA). Table 12-14 is an overview of the agreements in the construction stage of the interconnection serial process.

Table 12-14 Interconnection planning serial process: construction stage agreements

Study	Purpose
Affected System Study	PJM and its neighboring balancing authorities conduct interconnection studies to determine the impacts of interconnection requests on the neighboring transmission system.
Interim Deliverability Studies	Interim deliverability studies are conducted on a periodic basis in support of RPM auctions and other interconnection studies to determine if a new facility may come on line prior to its scheduled date. These studies evaluate the available system capability and provide the customer(s) with the availability of service by planning year. Interim deliverability studies use the same criteria used for the evaluation of the need for reinforcements associated with a project under study.
Long Term Firm Transmission Studies	Transmission service requests that extend beyond the available transfer capability horizon of 18 months are evaluated along with the other requests for service in the PJM new services queue to ensure deliverability. Long term firm transmission studies follow the same feasibility, system impact and facilities study process as new generation.

Planned Generation Additions

There were 8,190 generation request projects submitted in the new service request serial process queue from 1997 until the implementation of the new cycle process on July 10, 2023. As a result of the transition to the new services cycle process, 312 projects were moved to transition cycle 1 (TC1). There were 1,347 projects eligible to resubmit for evaluation in transition cycle 2 (TC2). Of those 1,347 eligible projects, 550 projects resubmitted and are now being evaluated in TC2. Of the 1,347 eligible projects, 797 projects did not resubmit, and were withdrawn from the queue. There were 1,070 projects initially entered into the AH2 queue and beyond. Those 1,070 projects are now considered invalid and have been removed from the queue. As a result of the transition to the cycle process, the 8,190 projects in the serial process queue has been reduced to 5,461 projects. Projects that will be evaluated in TC1 and TC2, and those projects no longer eligible to be evaluated in the serial process have been removed from the new service requests serial process metrics. New service requests cycle process metrics are reported separately from the serial process metrics.

Expected net revenues provide incentives to build new generation to serve PJM markets. The amount of planned new generation in PJM reflects investors' perception of the incentives provided by the combination of revenues from the PJM energy, capacity and ancillary service markets and from federal and state subsidies and incentives. On March 31, 2026, 40,220.7 MW were in generation request serial queues in the status of active, under construction or suspended, for construction through 2031. Although it is clear that not all generation in the queues will be built, PJM has added capacity steadily since markets were implemented on April 1, 1999.[68]

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. Table 12-15 shows the total MW in the serial queues by expected completion year and MW changes in the serial queue between December 31, 2025, and March 31, 2026, for ongoing projects, i.e. projects with the status active, under construction or suspended.[69]

68 See "*PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years*," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf>.

69 Expected completion dates are entered when the project enters the queue. Actual completion dates are generally different than expected completion dates.

Table 12-15 Serial queue comparison by expected completion year (MW): December 31, 2025 and March 31, 2026[70]

Year	As of 12/31/2025	As of 3/31/2026	Year Change MW	Percent
2008	0.0	0.0	0.0	0.0%
2009	0.0	0.0	0.0	0.0%
2010	0.0	0.0	0.0	0.0%
2011	0.0	0.0	0.0	0.0%
2012	0.0	0.0	0.0	0.0%
2013	0.0	0.0	0.0	0.0%
2014	0.0	0.0	0.0	0.0%
2015	0.0	0.0	0.0	0.0%
2016	0.0	0.0	0.0	0.0%
2017	0.0	0.0	0.0	0.0%
2018	44.0	44.0	0.0	0.0%
2019	0.0	0.0	0.0	0.0%
2020	0.0	0.0	0.0	0.0%
2021	116.0	116.0	0.0	0.0%
2022	0.0	0.0	0.0	0.0%
2023	190.0	105.0	(85.0)	(44.7%)
2024	514.1	219.1	(295.0)	(57.4%)
2025	3,204.0	2,508.6	(695.4)	(21.7%)
2026	11,653.8	10,336.5	(1,317.3)	(11.3%)
2027	10,038.1	9,470.8	(567.3)	(5.7%)
2028	8,349.4	9,519.4	1,170.0	14.0%
2029	3,847.9	5,637.9	1,790.0	46.5%
2030	1,280.0	1,280.0	0.0	0.0%
2031	983.4	983.4	0.0	0.0%
Total	40,220.7	40,220.7	0.0	0.0%

Table 12-16 shows the project status changes in more detail and how scheduled serial queue MW have changed between December 31, 2025, and March 31, 2026. For example, of the total 20,205.4 MW marked as active on December 31, 2025, 323.3 MW were withdrawn, 85.8 MW were suspended and 1,630.9 MW started construction by March 31, 2026. Analysis of projects that were suspended on December 31, 2025, show that 1,680.0 MW came out of suspension and are now active as of March 31, 2026.

Table 12-16 Change in project status (MW): December 31, 2025, to March 31, 2026

		Status at 3/31/2026				
Status at 12/31/2025	Total at 12/31/2025	Active	In Service	Under Construction	Suspended	Withdrawn
(Entered during 2025)	0.0	0.0	0.0	0.0	0.0	0.0
Active	20,205.4	18,165.4	0.0	1,630.9	85.8	323.3
In Service	94,867.1	0.0	94,867.1	0.0	0.0	0.0
Under Construction	11,398.6	80.0	311.0	10,847.6	0.0	160.0
Suspended	9,889.1	1,680.0	0.0	265.0	7,466.0	478.1
Withdrawn	472,867.2	0.0	0.0	0.0	0.0	472,867.2
Total	609,227.4	19,925.4	95,178.1	12,743.5	7,551.8	473,828.6

On March 31, 2026, 40,220.7 were in generation request serial queues in the status of active, suspended or under construction. Table 12-17 shows each status by unit type. Of the 19,925.4 MW in the status of active on March 31, 2026, 1,845.0 MW (9.3 percent) were combined cycle projects. Of the 12,743.5 MW in the status of under construction, 2,263.8 MW (17.8 percent) were combined cycle projects and 8,123.8 MW (63.7 percent) were solar projects. A significant amount of renewable hybrid projects (defined as solar + storage, solar + wind and wind + storage projects) have entered the queue in recent years. Of the 40,220.7 MW in the serial queues in the status of active on March 31, 2026, 1,727.6 MW (8.7 percent) were renewable hybrid projects. Of the 12,743.5 MW in the status of under construction, 161.6 MW (1.3 percent) were renewable hybrid projects.

70 Unless otherwise noted, wind and solar capacity totals in this section have not been adjusted to reflect derating.

Table 12-17 Current project status (MW) by unit type: March 31, 2026

	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
Active	2,062.2	1,845.0	1,027.7	50.0	0.0	0.0	0.0	51.0	0.0	0.0	0.0	0.0	11,584.3	1,727.6	0.0	0.0	0.0	0.0	0.0	1,577.7	0.0	19,925.4
Suspended	638.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4,851.8	0.0	0.0	0.0	0.0	0.0	0.0	2,061.8	0.0	7,551.8
Under Construction	390.0	2,263.8	90.0	0.0	0.0	0.0	0.0	0.0	44.0	0.0	0.0	0.0	8,123.8	161.6	0.0	36.0	0.0	0.0	0.0	1,634.3	0.0	12,743.5
Total	3,090.4	4,108.8	1,117.7	50.0	0.0	0.0	0.0	51.0	44.0	0.0	0.0	0.0	24,559.9	1,889.2	0.0	36.0	0.0	0.0	0.0	5,273.7	0.0	40,220.7

A significant shift in the distribution of unit types within the PJM footprint continues to develop as renewable, hybrid and other intermittent resources enter the queue, fewer natural gas fired units enter the queue, and coal fired steam units retire. As of March 31, 2026, of the 40,220.7 MW in the generation request serial queues in the status of active, suspended or under construction, 24,559.9 MW (61.6 percent) were solar projects, 5,273.7 MW (13.1 percent) were wind projects, 5,226.5 MW (13.0 percent) were natural gas fired projects (including combined cycle units, CTs, RICE units, and natural gas fired steam units), 1,889.2 MW (4.7 percent) were renewable hybrid projects (solar + storage, solar + wind and wind + storage units), and 36.0 MW (0.09 percent) were coal fired steam projects.

As of March 31, 2026, there were 5,117.0 MW of coal fired steam units and 2,528.0 MW of natural gas units slated for deactivation between April 1, 2026, and December 31, 2030 (See Table 12-11). The ongoing replacement of coal fired steam units by natural gas units will continue to significantly affect future congestion, the role of firm and interruptible gas supply, and natural gas supply infrastructure. The growing level of renewables, hybrids and other intermittents will have increasingly significant impacts on the energy and capacity markets.

On March 31, 2026, 28,919.1 MW, on an energy basis, were in generation request serial queues that had reached the construction service agreement milestone or equivalent, in the status of active, suspended or under construction. Table 12-18 shows the status by unit type. Of the 28,919.1 MW, 11,200.2 MW (38.7 percent) had not begun construction, 7,551.8 MW (26.1 percent) began construction, but are now suspended and 10,167.1 MW (35.2 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.

Table 12-18 Current status (MW) by unit type for projects that have reached the CSA Milestone: March 31, 2026

	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
Active	625.0	1,845.0	588.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6,117.7	646.6	0.0	0.0	0.0	0.0	0.0	1,377.7	0.0	11,200.2
Suspended	638.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4,851.8	0.0	0.0	0.0	0.0	0.0	0.0	2,061.8	0.0	7,551.8
Under Construction	340.0	2,263.8	90.0	0.0	0.0	0.0	0.0	0.0	44.0	0.0	0.0	0.0	5,597.4	161.6	0.0	36.0	0.0	0.0	0.0	1,634.3	0.0	10,167.1
Total	1,603.2	4,108.8	678.3	0.0	0.0	0.0	0.0	0.0	44.0	0.0	0.0	0.0	16,566.9	808.2	0.0	36.0	0.0	0.0	0.0	5,073.7	0.0	28,919.1

Table 12-19 shows the total MW in the status of active, in service, under construction, suspended, or withdrawn for each serial queue since the beginning of the RTEP process and the total MW that had been included in each queue. All projects in queues A-Z2 are either in service or have been withdrawn. As of March 31, 2026, there were 40,220.7 MW in serial queues that are not yet in service or withdrawn, of which 7,551.8 MW (18.8 percent) are suspended, 12,743.5 MW (31.7 percent) are under construction and 19,925.4 MW (49.5 percent) have not begun construction.

Table 12-19 Serial queue totals by status (MW): March 31, 2026[71]

Queue	Active	In Service	Under Construction	Suspended	Withdrawn	Total
A Expired 31-Jan-98	0.0	9,102.0	0.0	0.0	17,252.0	26,354.0
B Expired 31-Jan-99	0.0	4,292.4	0.0	0.0	14,958.8	19,251.2
C Expired 31-Jul-99	0.0	531.0	0.0	0.0	3,558.3	4,089.3
D Expired 31-Jan-00	0.0	850.6	0.0	0.0	7,358.0	8,208.6
E Expired 31-Jul-00	0.0	795.2	0.0	0.0	8,021.8	8,817.0
F Expired 31-Jan-01	0.0	52.0	0.0	0.0	3,092.5	3,144.5
G Expired 31-Jul-01	0.0	1,171.6	0.0	0.0	17,961.8	19,133.4
H Expired 31-Jan-02	0.0	702.5	0.0	0.0	8,421.9	9,124.4
I Expired 31-Jul-02	0.0	103.0	0.0	0.0	3,728.4	3,831.4
J Expired 31-Jan-03	0.0	42.0	0.0	0.0	846.0	888.0
K Expired 31-Jul-03	0.0	93.1	0.0	0.0	485.3	578.4
L Expired 31-Jan-04	0.0	256.5	0.0	0.0	4,033.7	4,290.2
M Expired 31-Jul-04	0.0	504.8	0.0	0.0	3,705.6	4,210.4
N Expired 31-Jan-05	0.0	2,398.8	0.0	0.0	8,129.3	10,528.0
O Expired 31-Jul-05	0.0	1,885.6	0.0	0.0	5,466.8	7,352.4
P Expired 31-Jan-06	0.0	3,290.3	0.0	0.0	5,320.5	8,610.8
Q Expired 31-Jul-06	0.0	3,147.9	0.0	0.0	11,385.7	14,533.6
R Expired 31-Jan-07	0.0	1,888.1	0.0	0.0	20,708.9	22,597.0
S Expired 31-Jul-07	0.0	3,596.4	0.0	0.0	12,396.5	15,992.9
T Expired 31-Jan-08	0.0	4,196.5	0.0	0.0	23,313.3	27,509.8
U1 Expired 30-Apr-08	0.0	218.9	0.0	0.0	7,937.8	8,156.7
U2 Expired 31-Jul-08	0.0	716.7	0.0	0.0	16,218.6	16,935.3
U3 Expired 31-Oct-08	0.0	333.0	0.0	0.0	2,635.6	2,968.6
U4 Expired 31-Jan-09	0.0	85.2	0.0	0.0	4,945.0	5,030.2
V1 Expired 30-Apr-09	0.0	197.9	0.0	0.0	2,572.8	2,770.7
V2 Expired 31-Jul-09	0.0	989.9	0.0	0.0	3,641.2	4,631.1
V3 Expired 31-Oct-09	0.0	1,132.0	0.0	0.0	3,822.7	4,954.7
V4 Expired 31-Jan-10	0.0	748.8	0.0	0.0	3,708.0	4,456.8
W1 Expired 30-Apr-10	0.0	567.4	0.0	0.0	5,139.5	5,706.9
W2 Expired 31-Jul-10	0.0	351.7	0.0	0.0	3,051.7	3,403.4
W3 Expired 31-Oct-10	0.0	504.3	0.0	0.0	8,695.9	9,200.2
W4 Expired 31-Jan-11	0.0	1,415.8	0.0	0.0	4,152.6	5,568.4
X1 Expired 30-Apr-11	0.0	1,101.7	0.0	0.0	6,200.6	7,302.3
X2 Expired 31-Jul-11	0.0	3,706.4	0.0	0.0	5,578.4	9,284.7
X3 Expired 31-Oct-11	0.0	109.2	0.0	0.0	7,665.9	7,775.1
X4 Expired 31-Jan-12	0.0	2,948.9	0.0	0.0	2,419.4	5,368.3
Y1 Expired 30-Apr-12	0.0	1,795.5	0.0	0.0	6,279.7	8,075.2
Y2 Expired 31-Oct-12	0.0	1,477.2	0.0	0.0	9,636.5	11,113.7
Y3 Expired 30-Apr-13	0.0	1,634.5	0.0	0.0	4,605.2	6,239.6
Z1 Expired 31-Oct-13	0.0	3,283.5	0.0	0.0	4,730.0	8,013.5
Z2 Expired 30-Apr-14	0.0	3,059.6	0.0	0.0	3,037.8	6,097.5
AA1 Expired 31-Oct-14	0.0	4,986.9	78.2	0.0	6,973.4	12,038.5
AA2 Expired 30-Apr-15	0.0	3,031.6	550.0	0.0	12,484.7	16,066.3
AB1 Expired 31-Oct-15	579.0	2,835.6	1,551.0	247.8	15,240.3	20,453.7
AB2 Expired 31-Mar-16	0.0	3,729.6	342.1	92.0	10,968.3	15,132.0
AC1 Expired 30-Sep-16	530.0	5,900.1	818.9	203.0	12,559.0	20,010.9
AC2 Expired 30-Apr-17	737.6	1,596.6	572.0	275.7	9,387.8	12,569.6
AD1 Expired 30-Sep-17	839.0	1,445.7	1,176.7	608.0	7,167.2	11,236.6
AD2 Expired 31-Mar-18	471.0	1,751.1	1,024.5	859.5	16,150.6	20,256.7
AE1 Expired 30-Sep-18	2,366.0	911.1	1,629.6	2,943.0	24,993.1	32,842.8
AE2 Expired 31-Mar-19	3,073.6	2,007.3	1,512.9	1,619.6	20,371.7	28,585.1
AF1 Expired 30-Sep-19	3,827.8	1,212.7	1,641.7	534.7	14,121.8	21,338.8
AF2 Expired 31-Mar-20	3,519.7	393.5	1,385.6	98.0	12,445.0	17,841.7
AG1 Expired 30-Sep-20	3,981.8	96.8	460.3	70.5	14,145.8	18,755.3
AG2 Expired 31-Mar-21	0.0	1.0	0.0	0.0	0.0	1.0
Total	19,925.4	95,178.1	12,743.5	7,551.8	473,828.6	609,227.4

71 Projects listed as partially in service are counted as in service for the purposes of this analysis.

Table 12-20 shows the projects with a status of active, suspended or under construction, by unit type, and control zone. As of March 31, 2026, 40,220.7 MW were in generation request serial queues for construction through 2031. Table 12-20 also shows the planned retirements for each zone.

Table 12-20 Serial queue totals for projects (active, suspended and under construction) by LDA, control zone and unit type (MW): March 31, 2026[72]

LDA	Zone	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total Queue Capacity	Planned Retirements
EMAAC	ACEC	50.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	160.9	38.0	0.0	0.0	0.0	0.0	0.0	432.0	0.0	680.9	175.1
	DPL	9.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	603.1	16.6	0.0	0.0	0.0	0.0	0.0	255.1	0.0	883.8	16.4
	JCPLC	310.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100.4	70.0	0.0	0.0	0.0	0.0	0.0	816.0	0.0	1,296.4	65.0
	PECO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	44.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	44.0	760.0
	PSEG	525.0	51.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	582.1	2.0
	REC	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
	EMAAC Total	894.0	51.1	0.0	0.0	0.0	0.0	0.0	0.0	44.0	0.0	0.0	0.0	870.4	124.6	0.0	0.0	0.0	0.0	0.0	1,503.1	0.0	3,487.2	1,018.5
SWMAAC	BGE	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	1,975.0
	PEPCO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	40.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	40.0	0.0
	SWMAAC Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	40.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	40.0	1,975.0
WMAAC	MEC	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	224.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	244.6	0.0
	PE	160.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,098.9	0.0	0.0	0.0	0.0	0.0	0.0	109.9	0.0	1,368.8	10.4
	PPL	170.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	608.4	60.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	838.4	0.0
	WMAAC Total	350.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,931.9	60.0	0.0	0.0	0.0	0.0	0.0	109.9	0.0	2,451.8	10.4
Non-MAAC	AEP	819.2	1,150.0	0.0	0.0	0.0	0.0	0.0	51.0	0.0	0.0	0.0	0.0	11,310.1	659.0	0.0	36.0	0.0	0.0	0.0	740.3	0.0	14,765.6	2,620.0
	AMPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	40.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	40.0	0.0
	APS	20.0	1,865.0	30.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,105.8	380.0	0.0	0.0	0.0	0.0	0.0	160.0	0.0	3,610.8	31.5
	ATSI	0.0	940.0	458.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,310.8	57.7	0.0	0.0	0.0	0.0	0.0	297.7	0.0	3,064.9	0.0
	COMED	180.0	102.7	60.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,120.9	19.9	0.0	0.0	0.0	0.0	0.0	2,384.6	0.0	3,868.1	2,671.9
	DAY	125.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	806.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	931.3	0.0
	DUKE	52.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	149.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	201.2	10.0
	DLCO	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
	DOM	650.0	0.0	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,493.6	588.0	0.0	0.0	0.0	0.0	0.0	78.2	0.0	7,378.8	2.0
	EKPC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	381.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	381.0	116.0
	OVEC	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
	RMU	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-MAAC Total	1,846.4	4,057.7	1,117.7	50.0	0.0	0.0	0.0	51.0	0.0	0.0	0.0	0.0	21,717.6	1,704.6	0.0	36.0	0.0	0.0	0.0	3,660.7	0.0	34,241.7	5,451.4
Total		3,090.4	4,108.8	1,117.7	50.0	0.0	0.0	0.0	51.0	44.0	0.0	0.0	0.0	24,559.9	1,889.2	0.0	36.0	0.0	0.0	0.0	5,273.7	0.0	40,220.7	8,455.3

72 This data includes only projects with a status of active, under construction, or suspended.

Withdrawn Projects

The serial queue contains a substantial number of projects that are not likely to be built. The serial queue process results in a substantial number of projects that are withdrawn. Manual 14B requires PJM to apply a commercial probability factor at the feasibility study stage to improve the accuracy of capacity and cost estimates. The commercial probability factor is based on the historical incidence of projects dropping out of the queue at the impact study stage, but the actual calculation of commercial probability factors is less than transparent.[73] The impact and facilities studies are performed using the full amount of planned generation in the queues.

Table 12-21 shows the milestone status when projects were withdrawn, for all withdrawn projects in the serial queue. Of the 3,769 projects withdrawn as of March 31, 2026, 1,577 (41.8 percent) were withdrawn before the system impact study was completed. Once a Construction Service Agreement (CSA) is executed, the financial obligation for any necessary transmission upgrades cannot be retracted. Of the 3,769 projects withdrawn, 856 projects (22.7 percent) were withdrawn after the completion of a Construction Service Agreement as of March 31, 2026.

Table 12-21 Last milestone at time of withdrawal: January 1, 1997 through March 31, 2026

Milestone Completed	Projects Withdrawn	Percent	Average Days	Maximum Days	MW Withdrawn
Never Started	513	13.6%	81	868	53,163.6
Feasibility Study	1,064	28.2%	290	1,633	196,263.0
System Impact Study	907	24.1%	829	3,248	115,206.2
Facilities Study	429	11.4%	1,300	4,107	58,753.4
Construction Service Agreement (CSA) or beyond	856	22.7%	1,528	7,864	50,442.5
Total	3,769	100.0%			473,828.6

Average Time in Serial Queue

Table 12-22 shows the time spent at various stages in the serial queue process and the completion time for the studies performed. For completed projects, there is an average time of 1,274 days, or 3.5 years, between entering a serial queue and going into service. For withdrawn projects, there is an average time of 806 days, or 2.2 years, between entering a serial queue and withdrawing.

Table 12-22 Project serial queue times by status (days): March 31, 2026[74]

Status	Average (Days)	Standard Deviation	Maximum
Active	2,441	407	3,834
In-Service	1,274	882	6,628
Suspended	2,713	407	3,865
Under Construction	2,787	510	4,242
Withdrawn	806	806	7,864

Table 12-23 presents information on the time in the stages of the serial queue for those projects not yet in service or already withdrawn. Of the 408 projects in the serial queue, in the status of active, under construction or suspended, as of March 31, 2026, 115 (28.2 percent) had a completed facilities study and 293 (71.8 percent) had a completed construction service agreement.

Table 12-23 Project serial queue times by milestone (days): March 31, 2026

Milestone Reached	Number of Projects	Percent of Total Projects	Average Days	Maximum Days
Under Review	0	0.0%	0	0
Feasibility Study	0	0.0%	0	0
System Impact Study	0	0.0%	0	0
Facilities Study	115	28.2%	2,261	2,745
Construction Service Agreement (CSA) or beyond	293	71.8%	2,732	4,242
Total	408	100.0%		

Table 12-24 shows the time spent in the serial queue by fuel type, and year the project entered the queue, for projects that are in service. The time from when a project enters the serial queue to the time the project goes in service has generally been decreasing compared to the period prior to 2017 although there are significant exceptions. For example, for a battery project entering the serial queue in 2015, there was an average of 2,062 days from the time it entered the queue until it went in service, compared to 1,409 days when entering the queue in 2018.

73 See "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 58 (December 17, 2025).

74 The queue data shows that some projects were withdrawn and a withdrawal date was not identified. These projects were removed for the purposes of this analysis.

Table 12-24 Average time in serial queue (days) by fuel type and year submitted (In Service Projects): March 31, 2026[75]

Unit Type	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Battery	983	609	417	710	789	2,062	941		1,409	1,289	1,084
CC	1,310	1,426	1,663	1,419	1,175	1,138	1,199	1,013	1,140	1,069	659
CT - Natural Gas	1,131	804	953	1,073	1,409	619	1,566	1,192	938	317	805
CT - Oil	717		259							280	349
CT - Other	729	634	954	1,248	718	360					
Fuel Cell						827				280	
Hydro - Pumped Storage						1,402					
Hydro - Run of River			1,325	614	332		580	426	606		
Nuclear	885	866		1,234			2,434	1,113	1,772		
RICE - Natural Gas			1,702	1,053	1,332	798		250		770	
RICE - Oil						1,849					
RICE - Other	638	1,385	1,479	241	627	622	491		466		
Solar	1,701	1,395	969	1,014	1,009	1,899	1,998	2,091	1,784	1,536	1,171
Solar + Storage						635	322		553		809
Solar + Wind											
Steam - Coal	745		513	1,010	583	853	684	647	1,810	2,139	
Steam - Natural Gas				1,182		421	751				1,286
Steam - Oil											
Steam - Other	256	838	643								
WInd	2,748	2,711	1,750	2,103	1,205	1,463	1,837	1,398	1,289		1,266
Wind + Storage							2,680				

75 A blank cell in this table means that no project of that fuel type, which was submitted to the queue in that year, subsequently went in service.

Table 12-25 shows 609,227.4 MW have entered PJM generation serial queues from January 1, 1997, through June 10, 2023. Table 12-25 presents totals by fuel type and projected in service date as of March 31, 2026. Of the 609,227.4 MW to enter the serial queue, 348,159.42 MW (57.1 percent) were thermal units.

Table 12-25 Total (MW Energy) by unit type and projected in service year: March 31, 2026

Year	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
1997	0.0	775.0	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	4,911.0	0.0	0.0	0.0	0.0	0.0	5,686.0
1998	0.0	4,659.0	0.0	0.0	3.1	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	4,662.1
1999	0.0	22,573.7	2.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.0	0.0	0.0	0.0	20.4	0.0	22,603.2
2000	0.0	9,900.8	409.6	0.0	3.8	0.0	0.0	0.0	0.0	0.0	0.0	1.2	0.0	0.0	0.0	20.0	0.0	0.0	0.0	0.0	0.0	10,335.3
2001	0.0	7,088.5	432.0	315.0	29.0	0.0	0.0	0.0	165.0	0.0	0.0	0.0	0.0	0.0	0.0	110.6	2.5	0.0	0.0	0.0	0.0	8,142.6
2002	0.0	2,622.2	2,442.0	6.5	0.0	0.0	0.0	107.0	60.0	0.0	0.0	2.9	0.0	0.0	0.0	42.0	10.0	0.0	0.0	65.5	0.0	5,358.1
2003	0.0	4,072.1	638.7	0.0	59.4	0.0	0.0	198.0	46.0	0.0	0.0	17.2	0.0	0.0	0.0	2.0	0.0	0.0	0.0	263.6	0.0	5,297.0
2004	0.0	14,918.2	77.3	33.0	16.1	0.0	0.0	41.0	0.0	8.0	23.3	0.0	0.0	0.0	0.0	42.0	0.0	0.0	0.0	75.0	0.0	15,233.9
2005	0.0	17,149.1	993.0	251.0	42.1	0.0	0.0	0.0	1,693.0	29.0	5.0	7.5	0.0	0.0	0.0	1,880.0	0.0	0.0	0.0	809.9	0.0	22,859.6
2006	0.0	6,033.0	23.3	49.5	43.4	0.0	0.0	147.2	0.0	2.0	30.5	58.5	0.0	0.0	0.0	527.0	0.0	0.0	529.0	1,480.2	0.0	8,923.6
2007	0.0	3,484.6	131.0	17.0	84.0	0.0	0.0	2.5	174.0	19.5	0.0	86.6	0.0	0.0	0.0	750.0	5.0	0.0	68.0	1,087.8	0.0	5,910.0
2008	1.0	7,003.4	628.0	59.3	38.4	0.0	0.0	2.9	331.0	0.0	0.0	57.6	3.3	0.0	0.0	254.5	101.0	0.0	20.0	2,098.6	0.0	10,599.0
2009	120.0	2,717.2	257.7	108.6	118.7	0.0	340.0	252.5	0.0	0.0	0.0	41.2	28.7	0.0	0.0	1,058.0	40.0	0.0	6.0	4,349.5	0.0	9,438.2
2010	16.0	1,912.9	137.8	83.9	320.7	0.0	16.0	94.9	301.0	10.5	0.0	15.8	231.4	0.0	0.0	5,599.0	0.0	0.0	80.8	9,286.1	0.0	18,106.8
2011	52.5	10,887.5	816.4	23.0	110.0	0.0	0.0	27.0	512.0	0.0	16.0	41.8	1,818.5	0.0	0.0	9,614.0	5.5	0.0	108.9	5,355.2	0.0	29,388.2
2012	27.0	13,786.8	389.5	310.0	121.3	0.0	0.0	82.9	391.0	0.0	6.4	2.0	1,892.3	0.0	0.0	3,407.0	0.0	0.0	426.6	7,637.1	0.0	28,479.8
2013	73.0	9,252.2	62.5	730.5	78.9	0.0	0.0	219.0	238.0	0.0	10.0	113.0	674.9	0.0	0.0	1,949.0	44.0	0.0	254.1	8,057.4	0.0	21,756.5
2014	159.1	7,105.5	0.0	684.0	96.0	0.0	0.0	1,120.0	74.0	0.0	0.0	13.3	904.5	0.0	0.0	3,288.0	0.0	0.0	63.8	11,758.7	186.0	25,452.9
2015	214.6	15,591.3	417.4	42.0	22.9	0.0	0.0	378.5	147.8	19.5	9.0	3.8	1,240.1	0.0	0.0	1,271.5	0.0	0.0	81.5	4,161.6	0.0	23,601.4
2016	422.5	16,553.3	332.1	0.0	144.9	2.8	0.0	71.2	4,082.0	46.9	0.0	30.2	1,737.6	3.4	0.0	50.0	40.0	0.0	107.8	4,459.3	0.0	28,083.9
2017	134.1	17,489.5	835.0	401.0	135.0	2.0	0.0	86.2	1,640.0	283.6	0.0	18.2	2,158.3	0.0	0.0	47.0	606.5	0.0	7.2	3,010.2	0.0	26,853.7
2018	175.0	17,902.0	404.9	0.0	11.6	1.1	34.0	12.5	1,644.0	95.0	0.0	41.0	3,369.9	0.6	0.0	148.0	57.0	0.0	0.0	5,135.7	0.0	29,032.3
2019	303.0	14,793.4	1,036.8	14.0	0.0	0.0	0.0	20.5	0.0	79.7	0.0	33.6	7,203.3	629.8	0.0	1,710.0	0.0	0.0	16.0	5,377.6	16.3	31,233.9
2020	621.7	7,243.7	1,173.0	0.0	0.0	2.1	0.0	2.4	128.0	39.9	4.0	0.8	5,726.6	615.5	0.0	20.0	64.0	0.0	0.0	8,886.7	0.0	24,528.4
2021	1,176.9	17,904.2	687.3	4.0	0.0	0.0	0.0	48.0	0.0	15.7	0.0	0.0	13,387.0	2,052.0	0.0	47.0	6.0	0.0	62.5	4,817.7	90.0	40,298.3
2022	2,677.1	12,723.2	1,629.3	0.0	0.0	0.0	1,000.0	28.0	0.0	20.0	0.0	0.0	10,837.9	1,578.3	0.0	0.0	0.0	0.0	0.0	2,249.7	0.0	32,743.4
2023	2,463.2	12,105.0	1,439.7	13.0	0.0	3.0	0.0	36.6	54.2	0.0	0.0	0.0	12,496.0	5,400.9	0.0	0.0	0.0	0.0	0.0	1,987.4	0.0	35,999.0
2024	619.5	4,522.5	646.0	0.0	0.0	0.0	0.0	12.0	1,594.0	0.0	0.0	0.0	7,251.5	1,041.1	0.0	0.0	5.0	0.0	0.0	4,228.2	0.0	19,919.8
2025	253.4	146.7	463.0	0.0	0.0	0.0	0.0	16.8	0.0	0.0	0.0	0.0	5,075.5	142.5	0.0	29.0	0.0	0.0	0.0	3,699.3	0.0	9,826.1
2026	716.0	1,515.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7,327.3	300.3	0.0	0.0	0.0	0.0	0.0	3,224.2	0.0	13,082.8
2027	768.2	676.1	735.0	0.0	0.0	0.0	200.0	0.0	0.0	0.0	0.0	0.0	8,348.4	373.0	0.0	0.0	0.0	0.0	0.0	1,958.8	0.0	13,059.5
2028	989.0	1,150.0	19.3	50.0	0.0	0.0	0.0	51.0	0.0	0.0	0.0	0.0	6,543.1	1,106.0	0.0	0.0	0.0	0.0	0.0	1,213.3	0.0	11,121.7
2029	830.0	1,865.0	599.0	0.0	0.0	0.0	0.0	9.5	0.0	0.0	0.0	0.0	2,643.9	620.0	0.0	0.0	0.0	0.0	0.0	2,709.7	0.0	9,277.1
2030	250.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,350.0
2031	0.0	0.0	439.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	150.0	394.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	983.4
Total	13,062.6	288,122.5	18,298.1	3,195.3	1,479.2	10.9	1,590.0	3,068.0	13,275.0	669.3	104.2	586.2	102,150.1	14,257.3	0.0	36,783.6	986.5	0.0	1,832.2	109,464.2	292.3	609,227.4

Table 12-26 shows there were 40,220.7 MW in the serial queue in the status of active, under construction and suspended as of March 31, 2026. Table 12-26 presents totals by fuel type and projected in service date. Of the 40,220.7 MW, 5,312.5 MW (13.2 percent) are thermal units. Of the 37,228.0 MW with projected in service dates between 2026 and 2031, 5,173.8 MW (12.9 percent) are thermal units.

Table 12-26 Total (MW Energy) by unit type and projected in service year (active, under construction and suspended): March 31, 2026

Year	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
1997	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
1998	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
1999	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
2000	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
2001	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
2002	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
2003	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
2004	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
2005	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
2006	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
2007	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
2008	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
2009	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
2010	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
2011	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
2012	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
2013	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
2014	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
2015	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
2016	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
2017	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
2018	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	44.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	44.0
2019	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
2020	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
2021	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	36.0	0.0	0.0	0.0	80.0	0.0	116.0
2022	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
2023	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	105.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	105.0
2024	40.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	92.5	6.6	0.0	0.0	0.0	0.0	0.0	80.0	0.0	219.1
2025	102.2	102.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,225.1	0.0	0.0	0.0	0.0	0.0	0.0	78.7	0.0	2,508.6
2026	676.0	940.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6,126.3	267.8	0.0	0.0	0.0	0.0	0.0	2,326.4	0.0	10,336.5
2027	647.2	51.1	60.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7,299.0	254.8	0.0	0.0	0.0	0.0	0.0	1,158.7	0.0	9,470.8
2028	865.0	1,150.0	19.3	50.0	0.0	0.0	0.0	51.0	0.0	0.0	0.0	0.0	5,488.1	746.0	0.0	0.0	0.0	0.0	0.0	1,150.0	0.0	9,519.4
2029	510.0	1,865.0	599.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,043.9	220.0	0.0	0.0	0.0	0.0	0.0	400.0	0.0	5,637.9
2030	250.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,030.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,280.0
2031	0.0	0.0	439.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	150.0	394.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	983.4
Total	3,090.4	4,108.8	1,117.7	50.0	0.0	0.0	0.0	51.0	44.0	0.0	0.0	0.0	24,559.9	1,889.2	0.0	36.0	0.0	0.0	0.0	5,273.7	0.0	40,220.7

Table 12-27 shows there were 473,828.6 MW withdrawn from the serial queue from January 1, 1997, through March 31, 2026. Table 12-27 presents totals by fuel type and projected in service date. Of the 473,828.6 MW withdrawn from the serial queue, 280,279.1 MW (59.2 percent) were thermal units. Of the 11,602.1 MW withdrawn with projected in service dates between 2026 and 2031, 1,875.0 MW (16.2 percent) were thermal units.

Table 12-27 Total (MW Energy) by unit type and projected in service year (withdrawn): March 31, 2026

Year	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
1997	0.0	775.0	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	4,911.0	0.0	0.0	0.0	0.0	0.0	5,686.0
1998	0.0	4,659.0	0.0	0.0	3.1	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	4,662.1
1999	0.0	22,573.7	2.1	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	22,575.8
2000	0.0	9,900.8	0.0	0.0	3.8	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	9,904.5
2001	0.0	6,988.5	0.0	0.0	5.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	51.6	0.0	0.0	0.0	0.0	0.0	7,045.1
2002	0.0	14.2	0.0	0.0	0.0	0.0	0.0	0.0	45.0	0.0	0.0	0.0	0.0	0.0	0.0	28.0	0.0	0.0	0.0	50.5	0.0	137.7
2003	0.0	1,287.1	0.0	0.0	59.4	0.0	0.0	0.0	2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	73.6	0.0	1,422.1
2004	0.0	12,073.2	0.0	0.0	12.0	0.0	0.0	41.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	75.0	0.0	12,201.2
2005	0.0	17,134.0	0.0	1.0	42.1	0.0	0.0	0.0	0.0	0.0	5.0	0.0	0.0	0.0	0.0	1,860.0	0.0	0.0	0.0	802.4	0.0	19,844.5
2006	0.0	4,847.0	0.0	0.0	43.4	0.0	0.0	142.0	0.0	0.0	30.5	0.0	0.0	0.0	0.0	520.0	0.0	0.0	0.0	1,430.2	0.0	7,013.1
2007	0.0	3,455.0	0.0	0.0	71.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	675.0	0.0	0.0	50.0	554.5	0.0	4,805.6
2008	1.0	6,826.0	0.0	0.0	38.4	0.0	0.0	2.9	18.0	0.0	0.0	0.0	0.0	0.0	0.0	152.0	0.0	0.0	0.0	1,857.0	0.0	8,895.3
2009	120.0	2,618.2	0.0	61.0	113.7	0.0	0.0	252.0	0.0	0.0	0.0	0.0	28.7	0.0	0.0	935.0	0.0	0.0	6.0	3,129.5	0.0	7,264.1
2010	16.0	1,776.9	0.0	81.0	302.5	0.0	0.0	54.9	0.0	0.0	0.0	0.0	168.5	0.0	0.0	5,512.0	0.0	0.0	20.8	7,853.1	0.0	15,785.7
2011	25.1	8,985.5	0.0	0.0	98.6	0.0	0.0	0.0	140.0	0.0	16.0	0.0	1,747.5	0.0	0.0	8,817.0	0.0	0.0	108.0	4,781.0	0.0	24,718.7
2012	20.5	13,711.5	0.5	310.0	87.7	0.0	0.0	82.9	0.0	0.0	6.4	0.0	1,801.8	0.0	0.0	2,751.0	0.0	0.0	426.6	6,535.0	0.0	25,733.9
2013	72.0	9,168.0	0.0	730.0	38.6	0.0	0.0	79.0	34.0	0.0	10.0	0.0	651.0	0.0	0.0	1,861.0	0.0	0.0	254.1	7,686.3	0.0	20,584.1
2014	114.1	6,438.0	0.0	684.0	96.0	0.0	0.0	1,085.1	74.0	0.0	0.0	0.0	809.7	0.0	0.0	3,212.0	0.0	0.0	10.0	11,308.7	0.0	23,831.6
2015	111.6	13,216.5	12.5	42.0	10.7	0.0	0.0	218.0	0.0	0.6	9.0	0.0	1,041.4	0.0	0.0	1,251.0	0.0	0.0	81.5	3,956.6	0.0	19,951.4
2016	400.1	9,812.3	35.4	0.0	144.0	2.0	0.0	71.2	3,980.0	26.0	0.0	11.7	1,484.8	0.0	0.0	50.0	0.0	0.0	107.8	4,181.8	0.0	20,307.1
2017	134.1	13,041.4	696.0	401.0	135.0	1.3	0.0	15.0	1,640.0	263.7	0.0	17.1	1,822.2	0.0	0.0	0.0	0.0	0.0	7.2	2,375.2	0.0	20,549.1
2018	109.5	10,224.0	64.9	0.0	11.6	1.1	0.0	0.0	1,600.0	89.8	0.0	36.2	3,017.5	0.0	0.0	80.0	27.0	0.0	0.0	4,618.0	0.0	19,879.6
2019	303.0	10,812.9	922.8	14.0	0.0	0.0	0.0	15.0	0.0	39.9	0.0	33.6	6,771.8	629.8	0.0	1,710.0	0.0	0.0	16.0	4,286.6	16.3	25,571.6
2020	621.7	5,987.7	1,022.0	0.0	0.0	2.1	0.0	0.0	100.0	39.9	0.0	0.0	4,789.8	614.4	0.0	20.0	0.0	0.0	0.0	7,786.4	0.0	20,984.0
2021	1,175.4	14,345.5	330.3	0.0	0.0	0.0	0.0	48.0	0.0	1.3	0.0	0.0	12,267.5	2,048.8	0.0	0.0	6.0	0.0	0.0	4,178.0	90.0	34,490.8
2022	2,650.3	8,412.3	1,533.8	0.0	0.0	0.0	1,000.0	28.0	0.0	20.0	0.0	0.0	9,412.3	1,578.3	0.0	0.0	0.0	0.0	0.0	2,249.7	0.0	26,884.7
2023	2,408.2	10,861.0	851.5	0.0	0.0	0.0	0.0	36.6	0.0	0.0	0.0	0.0	9,253.0	5,383.9	0.0	0.0	0.0	0.0	0.0	1,705.0	0.0	30,499.2
2024	577.0	4,522.5	646.0	0.0	0.0	0.0	0.0	12.0	1,594.0	0.0	0.0	0.0	3,964.6	1,034.5	0.0	0.0	0.0	0.0	0.0	4,047.4	0.0	16,398.0
2025	115.5	44.0	463.0	0.0	0.0	0.0	0.0	16.8	0.0	0.0	0.0	0.0	641.7	142.5	0.0	0.0	0.0	0.0	0.0	3,176.7	0.0	4,600.2
2026	40.0	575.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,189.1	32.5	0.0	0.0	0.0	0.0	0.0	885.2	0.0	2,721.8
2027	121.0	625.0	675.0	0.0	0.0	0.0	200.0	0.0	0.0	0.0	0.0	0.0	1,029.5	118.2	0.0	0.0	0.0	0.0	0.0	800.1	0.0	3,568.8
2028	124.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,055.0	360.0	0.0	0.0	0.0	0.0	0.0	63.3	0.0	1,602.3
2029	320.0	0.0	0.0	0.0	0.0	0.0	0.0	9.5	0.0	0.0	0.0	0.0	600.0	400.0	0.0	0.0	0.0	0.0	0.0	2,309.7	0.0	3,639.2
2030	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	70.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	70.0
2031	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
Total	9,580.0	235,711.6	7,255.8	2,324.0	1,316.7	6.4	1,200.0	2,209.9	9,227.0	481.2	76.9	98.6	63,617.6	12,342.9	0.0	34,396.6	33.0	0.0	1,088.0	92,756.2	106.3	473,828.6

Completion Rates

The probability of a project going into service increases as each step of the serial planning process is completed. Table 12-28 shows the historic completion rates (MW energy) by unit type for projects that have completed the system impact study (SIS), facilities study agreement (FSA) and any milestone completed beyond the FSA including a Construction Service Agreement (CSA), Interconnection Service Agreement (ISA), Upgrade Construction Service Agreement

(UCSA) and Wholesale Market Participant Agreement (WMPA) as well as the historic completion rates for all projects including those withdrawn before reaching the SIS milestone.[76] For each unit type, the total MW in service was divided by the total energy MW entered in the serial queue. To calculate the completion rates for projects that reached the individual milestones, only those projects that reached a final status of withdrawn or in service were evaluated. For example, if a project was withdrawn after the completion of its SIS, but before the completion of the FSA, the totals would be included in the calculation of the SIS completion rate, but not in the calculation of the FSA or CSA completion rates. Similarly, if a project was withdrawn after the completion of its FSA, but before the completion of the CSA, the totals would be included in the calculation of the SIS and FSA completion rates, but not in the calculation of the CSA completion rate. The completion rates show that of all battery projects to ever enter the serial queue and complete the system impact study stage, 6.6 percent of the queued MW have gone into service. The completion rate for battery projects increases to 15.9 percent when battery projects complete the facility study agreement and further increases to 37.3 percent when battery projects complete the construction service agreement. Of all battery projects to enter the serial queue, only 3.1 percent of the queued MW have gone into service.

76 All milestones after the FSA are included in the totals under the CSA headings of the tables within Section 12, "Generation and Transmission Planning."

Table 12-28 Historic completion rates (MW energy) by unit type for projects with a completed SIS, FSA and CSA: March 31, 2026

Unit Type	Completion Rate (SIS)	Completion Rate (FSA)	Completion Rate (CSA)	Completion Rate (ALL)
Battery	6.6%	15.9%	37.3%	3.1%
CC	33.9%	49.6%	71.4%	16.9%
CT - Natural Gas	59.3%	70.4%	72.1%	50.0%
CT - Oil	35.7%	60.0%	90.9%	25.0%
CT - Other	12.1%	18.4%	29.5%	10.6%
Fuel Cell	50.6%	51.8%	51.8%	41.4%
Hydro - Pumped Storage	35.8%	35.8%	66.1%	24.5%
Hydro - Run of River	40.2%	55.5%	61.5%	20.7%
Nuclear	34.3%	41.4%	51.3%	28.2%
RICE - Natural Gas	32.4%	44.7%	49.4%	28.0%
RICE - Oil	34.0%	59.7%	59.7%	26.2%
RICE - Other	88.9%	91.3%	92.0%	77.9%
Solar	29.1%	45.9%	62.0%	15.0%
Solar + Storage	0.4%	1.0%	2.3%	0.2%
Solar + Wind	0.0%	0.0%	0.0%	0.0%
Steam - Coal	13.8%	25.7%	37.9%	6.4%
Steam - Natural Gas	90.5%	91.1%	91.1%	90.5%
Steam - Oil	0.0%	0.0%	0.0%	0.0%
Steam - Other	31.0%	40.6%	48.6%	28.0%
Wind	16.8%	32.6%	50.0%	10.4%
Wind + Storage	45.3%	45.3%	45.3%	45.3%

On March 31, 2026, 40,220.7 MW were in generation request serial queues in the status of active, under construction or suspended. Of the total 40,220.7 MW in the queue, 28,919.1 MW (71.9 percent) have reached the CSA milestone and 11,301.6 MW (28.1 percent) have not received a completed CSA. Based on historical completion rates, (applying the unit type specific completion rates for those projects that have reached the SIS, FSA or any milestone beyond the FSA, and using the overall completion rates for those projects that have not yet reached the SIS milestone), 21,232.8 MW (52.8 percent) of new generation in the serial queue are expected to go into service.

Table 12-29 shows the percent of all project MW, by unit type, to go in service by year submitted to the serial queue. Of all battery projects that entered the serial queue in 2010, 65.5 percent reached the status of in service by March 31, 2026. Of all battery projects that entered the serial queue in 2016, only 1.3 percent have reached the status of in service as of March 31, 2026.

Table 12-29 Percent of all projects (MW energy) to go in service by unit type and year submitted to the serial queue: March 31, 2026

Unit Type	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Battery	65.5%	8.3%	15.1%	45.7%	21.5%	11.5%	1.3%	0.0%	3.1%	0.9%	0.4%
CC	14.6%	24.5%	30.8%	35.6%	53.6%	13.4%	20.7%	8.1%	4.1%	2.7%	NA
CT - Natural Gas	100.0%	98.3%	71.6%	42.2%	56.8%	0.2%	13.2%	38.9%	8.4%	5.4%	7.2%
CT - Oil	100.0%	NA	1.2%	0.0%	0.0%	NA	NA	NA	0.0%	100.0%	7.4%
CT - Other	28.8%	26.2%	36.1%	100.0%	11.5%	100.0%	NA	0.0%	NA	NA	NA
Fuel Cell	NA	NA	NA	NA	NA	67.4%	0.0%	0.0%	NA	100.0%	NA
Hydro - Pumped Storage	NA	NA	NA	NA	NA	100.0%	NA	NA	0.0%	0.0%	NA
Hydro - Run of River	0.0%	0.0%	57.6%	49.6%	11.2%	NA	100.0%	26.8%	100.0%	0.0%	0.0%
Nuclear	15.5%	1.6%	0.0%	100.0%	NA	NA	25.4%	100.0%	100.0%	NA	0.0%
RICE - Natural Gas	NA	NA	100.0%	66.7%	5.4%	6.2%	0.0%	5.4%	NA	100.0%	NA
RICE - Oil	0.0%	0.0%	NA	NA	NA	30.8%	NA	NA	NA	NA	NA
RICE - Other	100.0%	100.0%	100.0%	100.0%	79.7%	25.5%	2.8%	0.0%	100.0%	NA	NA
Solar	10.7%	8.1%	16.9%	24.4%	38.8%	30.5%	40.1%	16.7%	7.1%	11.8%	1.7%
Solar + Storage	NA	NA	NA	NA	NA	100.0%	0.7%	0.0%	0.0%	0.0%	0.4%
Solar + Wind	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Steam - Coal	100.0%	0.0%	1.4%	68.4%	1.2%	23.4%	37.5%	100.0%	59.2%	100.0%	NA
Steam - Natural Gas	NA	NA	NA	100.0%	0.0%	100.0%	100.0%	100.0%	NA	NA	45.5%
Steam - Oil	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Steam - Other	0.5%	61.2%	16.6%	0.0%	0.0%	NA	NA	NA	NA	NA	NA
WInd	6.1%	3.4%	2.5%	20.9%	20.7%	12.5%	26.8%	2.6%	1.2%	0.0%	0.6%
Wind + Storage	NA	NA	NA	NA	NA	NA	0.0%	0.0%	NA	NA	NA
All	11.6%	19.0%	25.9%	35.9%	43.0%	15.8%	27.3%	12.5%	4.2%	7.1%	1.4%

Table 12-30 shows the total MW that went in service each year, by unit type, since 1999. In the first three months of 2026, 40.1 MW from the serial queue went in service. Of the 40.1 MW that went in service, 15.7 MW (39.1 percent) were battery units, 12.6 MW (31.5 percent) were wind units and 11.8 MW (29.4 percent) were solar units.

Table 12-30 Total (MW Energy) by unit type and year project went in service: March 31, 2026

Unit Type	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Battery	4.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	27.4	4.5	23.0	24.0	110.4	10.0	2.0	40.0	25.5	0.0	1.5	0.0	61.8	42.5	0.0	15.7
CC	0.0	0.0	100.0	2,608.0	2,785.0	2,845.0	15.1	1,196.0	4.0	177.0	52.0	136.0	1,869.0	162.7	82.2	2,155.7	2,977.7	5,418.0	3,888.1	10,865.0	2,983.0	88.0	3,424.7	1,825.9	2,644.0	0.0	0.0	0.0
CT - Natural Gas	0.0	409.6	432.0	2,442.0	638.7	61.3	993.0	39.3	97.0	821.0	181.7	97.8	850.4	393.0	95.0	125.2	317.9	72.0	212.0	388.0	104.0	156.0	314.0	151.6	532.1	0.0	0.0	0.0
CT - Oil	4.0	0.0	315.0	6.5	0.0	33.0	292.0	7.5	21.0	15.3	85.6	0.0	23.9	2.0	0.5	2.0	0.0	0.0	0.0	0.0	0.0	13.0	0.0	0.0	0.0	0.0	0.0	0.0
CT - Other	0.0	0.0	10.0	0.0	0.0	4.1	0.0	0.0	11.0	6.9	0.0	18.2	0.0	70.7	17.6	6.0	9.0	5.9	0.0	0.0	3.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cell	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	1.5	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro - Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	340.0	16.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	34.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro - Run of River	0.0	0.0	0.0	107.0	196.0	2.0	0.0	5.7	2.5	0.0	54.2	180.0	27.0	0.0	6.0	28.9	160.5	0.0	29.5	5.5	0.0	2.4	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	0.0	0.0	165.0	15.0	44.0	0.0	1,693.0	242.0	130.0	115.0	0.0	281.0	422.0	328.0	117.0	80.0	54.0	133.8	130.0	0.0	0.0	0.0	0.0	0.0	54.2	0.0	0.0	0.0
RICE - Natural Gas	0.0	0.0	0.0	0.0	0.0	8.0	29.0	2.0	19.5	0.0	0.0	10.5	0.0	0.0	0.0	0.0	18.9	20.9	19.9	5.2	39.8	0.0	14.4	0.0	0.0	0.0	0.0	0.0
RICE - Oil	0.0	0.0	0.0	0.0	0.0	23.3	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	4.0	0.0	0.0	0.0	0.0	0.0	0.0
RICE - Other	0.0	1.2	0.0	2.9	17.2	0.0	27.5	44.9	86.6	57.6	38.8	13.8	39.8	2.0	109.0	0.0	3.8	19.3	22.4	0.0	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar	12.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.3	5.1	6.8	137.2	98.9	44.4	59.8	172.1	290.8	450.9	284.5	555.6	1,670.8	807.5	1,078.5	1,283.9	4,451.0	2,547.7	11.8
Solar + Storage	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	0.0	1.0	2.0	1.1	0.0	3.2	0.0	17.0	0.0	0.0	0.0
Solar + Wind	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	0.0	0.0	0.0	0.0
Steam - Coal	12.0	20.0	59.0	21.0	0.0	37.0	20.0	14.0	55.0	720.5	123.0	177.0	97.0	708.0	48.0	16.0	92.5	0.0	47.0	24.0	20.0	0.0	11.0	0.0	0.0	0.0	29.0	0.0
Steam - Natural Gas	0.0	0.0	2.5	10.0	0.0	0.0	0.0	0.0	25.0	145.0	0.0	0.0	5.5	0.0	0.0	0.0	0.0	696.5	0.0	0.0	0.0	64.0	0.0	0.0	0.0	5.0	0.0	0.0
Steam - Oil	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	0.0	0.0	0.0	0.0
Steam - Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	529.0	18.0	20.0	0.0	122.5	0.9	0.0	50.0	3.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WInd	0.0	0.0	0.0	15.0	190.0	20.4	7.5	380.0	867.3	725.2	620.0	1,183.5	275.6	1,423.1	150.0	500.0	455.0	465.8	700.7	762.0	535.0	1,008.4	310.0	0.0	282.4	289.8	254.9	12.6
Wind + Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	186.0	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
Total	32.0	430.8	1,083.5	5,227.4	3,870.9	3,034.1	3,077.1	2,460.4	1,522.9	2,806.8	1,500.4	2,243.1	3,775.6	3,192.8	742.7	3,001.4	4,372.8	7,133.0	5,503.5	12,411.7	4,268.0	3,009.6	4,886.2	3,056.0	4,875.4	4,788.3	2,831.6	40.1

Analysis by Fuel Group

The time it takes to complete a study depends on the backlog and the number of projects in the serial queue, but not on the size of the project. Table 12-31 shows the number of projects that entered the serial queue by year and by fuel group. The fuel groups are nuclear units, renewable units (including hydro run of river, solar and wind units (including renewable solar and wind hybrids), storage units (including battery and pumped storage hydro units), thermal units (including combined cycle, CT natural gas and oil, RICE natural gas and oil and steam coal, natural gas and oil) and other units (all other fuels). Of the 2,809 projects entered from January 2015 through June 2023, 2,062 projects (73.4 percent) were renewable.

Table 12-31 Number of projects entered in the serial queue by fuel group: March 31, 2026

	Fuel Group										
Year Entered	Nuclear	Percent Nuclear	Renewable	Percent Renewable	Storage	Percent Storage	Thermal	Percent Thermal	Other	Percent Other	Total
1997	2	15.38%	0	0.00%	0	0.00%	11	84.62%	0	0.00%	13
1998	0	0.00%	0	0.00%	0	0.00%	18	100.00%	0	0.00%	18
1999	1	1.11%	5	5.56%	0	0.00%	82	91.11%	2	2.22%	90
2000	2	2.41%	3	3.61%	0	0.00%	75	90.36%	3	3.61%	83
2001	4	4.40%	6	6.59%	0	0.00%	78	85.71%	3	3.30%	91
2002	3	5.88%	15	29.41%	0	0.00%	23	45.10%	10	19.61%	51
2003	1	1.89%	34	64.15%	0	0.00%	13	24.53%	5	9.43%	53
2004	4	7.41%	17	31.48%	0	0.00%	23	42.59%	10	18.52%	54
2005	3	2.26%	74	55.64%	1	0.75%	36	27.07%	19	14.29%	133
2006	9	5.73%	67	42.68%	0	0.00%	47	29.94%	34	21.66%	157
2007	9	4.11%	64	29.22%	1	0.46%	123	56.16%	22	10.05%	219
2008	3	1.39%	102	47.22%	7	3.24%	79	36.57%	25	11.57%	216
2009	10	5.78%	107	61.85%	2	1.16%	34	19.65%	20	11.56%	173
2010	5	1.13%	370	83.90%	5	1.13%	40	9.07%	21	4.76%	441
2011	6	1.69%	264	74.37%	4	1.13%	61	17.18%	20	5.63%	355
2012	2	1.26%	59	37.11%	11	6.92%	69	43.40%	18	11.32%	159
2013	1	0.65%	54	35.06%	21	13.64%	69	44.81%	9	5.84%	154
2014	0	0.00%	100	52.08%	21	10.94%	59	30.73%	12	6.25%	192
2015	0	0.00%	130	42.07%	63	20.39%	103	33.33%	13	4.21%	309
2016	2	0.50%	284	71.18%	22	5.51%	65	16.29%	26	6.52%	399
2017	2	0.56%	280	78.87%	7	1.97%	47	13.24%	19	5.35%	355
2018	1	0.23%	336	77.42%	50	11.52%	46	10.60%	1	0.23%	434
2019	0	0.00%	487	78.30%	85	13.67%	49	7.88%	1	0.16%	622
2020	2	0.29%	545	78.99%	122	17.68%	21	3.04%	0	0.00%	690
2021	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0
2022	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0
2023	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0
Total	72	1.32%	3,403	62.31%	422	7.73%	1,271	23.27%	293	5.37%	5,461

As of March 31, 2026, renewable projects make up 85.0 percent of all projects in the serial queue and those projects account for 79.0 percent of the nameplate MW currently active, suspended or under construction.

Table 12-32 Serial queue details by fuel group: March 31, 2026

Fuel Group	Number of Projects	Percent of Projects	MW	Percent MW
Nuclear	1	0.2%	44.0	0.1%
Renewable	347	85.0%	31,773.8	79.0%
Storage	43	10.5%	3,090.4	7.7%
Thermal	17	4.2%	5,312.5	13.2%
Other	0	0.0%	0.0	0.0%
Total	408	100.0%	40,220.7	100.0%

Historical completion rates for renewable projects may not be an accurate predictor of completion rates for current renewable projects. The outcomes for current projects will provide additional information and improve the ability to assess the likely future generation mix based on the type of projects in the queue.

Since wind resources cannot be dispatched on demand, PJM rules previously required that the unforced capacity of wind resources be derated to 20 percent of nameplate capacity until actual generation data are available. Beginning with Queue U, PJM derated wind resources to 13 percent of nameplate capacity until there was operational data to support a different conclusion.[77] PJM derated solar resources to 38 percent of nameplate capacity. Effective June 1, 2017, PJM adjusted the derates of wind and solar resources. The capacity factor derates for wind resources were dependent on the wind farm locations and had an average derate of 16.2 percent. The capacity factor derates for solar resources were dependent on the solar installation type and had an average derate of 46.7 percent.

Beginning with the 2023/2024 Delivery Year, unforced capacity for intermittent resources and limited duration resources are determined by PJM's effective load carrying capability (ELCC) analysis. The PJM ELCC analysis determines capacity derates by resource class for each Delivery Year. The unforced capacity derate for a specific resource will equal the product of the ELCC class rating and a resource specific performance factor. For example, the 2028/2029 Base Residual Auction ELCC class rating for onshore wind resources is 34.0 percent, for solar resources with tracking panels is 10.0 percent and for solar

77 See "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 58 (December 17, 2025).

resources with fixed panels is 7.0 percent.[78] The ELCC class rating for battery or storage resources replaces the 10 hour rule that was previously used to determine the unforced capacity value for a storage resource. PJM defined four different storage classes differentiated by duration. The ELCC class rating is 59.0 percent for storage resources that can continuously generate energy at the nameplate capacity for four hours (four hour storage). The ELCC class rating is 68.0 percent for six hour storage and 71.0 percent for eight hour storage and 78.0 percent for 10 hour storage.

While renewables currently make up the majority of both projects and nameplate MW in the serial queue, historical completion rates and derating factors must be accounted for when evaluating the share of capacity resources that are likely to be contributed by renewables. Table 12-33 shows the total MW of all projects in the serial queue as of March 31, 2026, in the status of active, suspended and under construction, by unit type. Table 12-33 also shows the total MW Energy and MW Capacity for each fuel type adjusted based on current historical completion rates and, for Capacity MW in the queue, adjusted for ELCC derates.[79]

Table 12-33 shows that of the 5,312.5 MW, on an energy basis, of thermal projects (including combined cycle, CT natural gas and coal fired steam projects) in the serial queue, 3,775.7 MW (71.1 percent) are expected to go in service based on historical completion rates as of March 31, 2026.

Of the 3,090.4 MW, on an energy basis, of battery projects in the serial queue, 834.5 MW (27.0 percent) are expected to go in service based on historical completion rates as of March 31, 2026.

Of the 31,773.8 MW, on an energy basis, of renewable projects in the serial queue, 16,600.0 MW (52.2 percent) are expected to go in service based on historical completion rates as of March 31, 2026.

Of the 3,899.1 MW, on a capacity basis that requested CIRs, of combined cycle projects requested in the generation serial queues in the status of active, under construction or suspended, 2,752.8 MW (70.6 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 2028/2029 Base Residual Auction, the 3,899.1 MW of capacity requests currently under construction, suspended or active in the serial queue would be reduced to 2,147.2 MW of capacity (55.1 percent of the total requested capacity).

Of the 5,140.6 MW, on a capacity basis that requested CIRs, of thermal projects (including combined cycle, CT natural gas and coal fired steam projects) requested in the generation serial queues in the status of active, under construction or suspended, 3,587.9 MW (69.8 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 2028/2029 Base Residual Auction,[80] the 5,140.6 MW of capacity requests currently under construction, suspended or active in the serial queue would be reduced to 2,713.4 MW of capacity (52.8 percent of the total requested capacity).

Of the 2,082.6 MW, on a capacity basis that requested CIRs, of battery projects requested in the generation serial queues in the status of active, under construction or suspended, 234.1 MW (11.2 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 2028/2029 Base Residual Auction, the 2,082.6 MW of capacity requests currently under construction, suspended or active in the serial queue would be reduced to 138.1 MW of capacity (6.6 percent of the total requested capacity).

Of the 16,418.1 MW, on a capacity basis that requested CIRs, of renewable projects requested in the generation serial queues in the status of active, under construction or suspended, 8,575.2 MW (52.2 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 2028/2029 Base Residual Auction, the 16,418.1 MW of capacity requests currently under

78 Unless otherwise noted, the ELCC derate factors in this section are based on the *ELCC Class Ratings for 2028/2029 Base Residual Auction*, PJM Interconnection L.L.C. (February 25, 2026) <https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/28-29-bra-elcc-class-ratings.pdf>.

79 Unless otherwise noted, the ELCC derate adjusted MW are calculated using the 2028/2029 Base Residual Auction ELCC factors. The adjusted MW are calculated using the four hour storage ELCC derate of 59.0 percent for battery resources, 34.0 percent ELCC derate for wind resources and 10.0 percent ELCC derate for solar resources.

80 Unless otherwise noted, the ELCC derate factors in this section are based on the *ELCC Class Ratings for 2028/2029 Base Residual Auction*, PJM Interconnection L.L.C. (February 25, 2026) <https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/28-29-bra-elcc-class-ratings.pdf>.

construction, suspended or active in the serial queue would be reduced to 986.5 MW of capacity (6.0 percent of the total requested capacity).

As of March 31, 2026, 23,685.3 MW of capacity requests (requested CIRs) were in the generation serial queues in the status of active, under construction or suspended. Based on historical completion rates, 12,419.2 MW (52.4 percent) are expected to go into service. Based on historical completion rates and the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction, the 23,685.3 MW of capacity requests currently under construction, suspended or active in the serial queue would be reduced to 3,859.2 MW of capacity (16.3 percent of the total requested capacity).

Table 12-33 Serial queue totals for projects (active, suspended and under construction) by unit type adjusted for current historical completion rates and ELCC derates (MW): March 31, 2026

	Energy (MW)		Capacity (MW)		
Unit Type	Total	Completion Rate Adjusted	Total	Completion Rate Adjusted	Completion Rate and ELCC Adjusted
Battery	3,090.4	834.5	2,082.6	234.1	138.1
CC	4,108.8	2,933.7	3,899.1	2,752.8	2,147.2
CT - Natural Gas	1,117.7	798.4	1,155.5	795.1	532.7
CT - Oil	50.0	30.0	50.0	26.4	21.9
CT - Other	0.0	0.0	0.0	0.0	0.0
Fuel Cell	0.0	0.0	0.0	0.0	0.0
Hydro - Pumped Storage	0.0	0.0	0.0	0.0	0.0
Hydro - Run of River	51.0	28.3	30.0	17.2	6.0
Nuclear	44.0	22.6	44.0	22.1	21.2
RICE - Natural Gas	0.0	0.0	0.0	0.0	0.0
RICE - Oil	0.0	0.0	0.0	0.0	0.0
RICE - Other	0.0	0.0	0.0	0.0	0.0
Solar	24,559.9	13,940.3	14,008.1	8,021.5	802.1
Solar + Storage	1,889.2	29.4	1,340.6	16.8	1.7
Solar + Wind	0.0	0.0	0.0	0.0	0.0
Steam - Coal	36.0	13.6	36.0	13.7	11.6
Steam - Natural Gas	0.0	0.0	0.0	0.0	0.0
Steam - Oil	0.0	0.0	0.0	0.0	0.0
Steam - Other	0.0	0.0	0.0	0.0	0.0
Wind	5,273.7	2,602.1	1,039.4	519.7	176.7
Wind + Storage	0.0	0.0	0.0	0.0	0.0
Total	40,220.7	21,232.8	23,685.3	12,419.2	3,859.2

Analysis by Unit Type and Project Classification

Table 12-34 shows the status of all generation serial queue projects by unit type and project classification as of March 31, 2026. As of March 31, 2026, 5,461 projects, representing 609,227.4 MW, have entered the serial queue process from 1997 until the implementation of the new cycle process on July 10, 2023. Of those, 1,284 projects, representing 95,178.1 MW (15.6 percent of the MW), went into service. Of the projects that entered the serial queue process, 3,769 projects, representing 473,828.6 MW (77.8 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.

A total of 4,353 projects have been classified as new generation and 1,108 projects have been classified as upgrades. Natural gas, wind, solar and renewable hybrid projects (including solar + storage, solar + wind and wind + storage) have accounted for 4,360 projects (79.8 percent) of all 5,461 generation serial queue projects to enter the queue since January 1, 1997.

Table 12-34 Status of all generation serial queue projects: March 31, 2026

		Number of Projects																					
Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	32	67	50	10	25	2	0	10	2	11	0	55	318	6	0	8	6	0	4	100	1	707
	Upgrade	9	117	137	25	5	1	3	19	45	9	2	16	89	1	0	59	10	0	8	21	1	577
Under Construction	New Generation	3	3	0	0	0	0	0	0	0	0	0	0	68	4	0	0	0	0	0	6	0	84
	Upgrade	1	3	2	0	0	0	0	0	1	0	0	0	15	1	0	1	0	0	0	1	0	25
Suspended	New Generation	8	0	0	0	0	0	0	0	0	0	0	0	64	0	0	0	0	0	0	7	0	79
	Upgrade	3	0	0	0	0	0	0	0	0	0	0	0	14	0	0	0	0	0	0	2	0	19
Withdrawn	New Generation	239	440	32	10	82	28	4	48	9	29	12	16	1,648	155	0	55	1	0	34	488	1	3,331
	Upgrade	92	107	25	13	12	0	0	4	15	0	2	3	109	5	0	15	2	0	2	31	1	438
Active	New Generation	20	2	1	1	0	0	0	0	0	0	0	0	105	17	0	0	0	0	0	6	0	152
	Upgrade	8	0	4	0	0	0	0	1	0	0	0	0	33	1	0	0	0	0	0	2	0	49
Total Projects	New Generation	302	512	83	21	107	30	4	58	11	40	12	71	2,203	182	0	63	7	0	38	607	2	4,353
	Upgrade	113	227	168	38	17	1	3	24	61	9	4	19	260	8	0	75	12	0	10	57	2	1,108

Table 12-35 shows the totals in Table 12-34 by share of classification as new generation or upgrade. Within a unit type the shares of upgrades add to 100 percent and the shares of new generation add to 100 percent. For example, 79.2 percent of all hydro run of river projects classified as upgrades are currently in service in PJM, 16.7 percent of hydro run of river upgrades were withdrawn and 4.2 percent of hydro run of river upgrades are active in the serial queue.

Table 12-35 Status of all generation serial queue projects as a percent of total projects by classification: March 31, 2026

		Percent of Projects																					
Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	10.6%	13.1%	60.2%	47.6%	23.4%	6.7%	0.0%	17.2%	18.2%	27.5%	0.0%	77.5%	14.4%	3.3%	0.0%	12.7%	85.7%	0.0%	10.5%	16.5%	50.0%	16.2%
	Upgrade	8.0%	51.5%	81.5%	65.8%	29.4%	100.0%	100.0%	79.2%	73.8%	100.0%	50.0%	84.2%	34.2%	12.5%	0.0%	78.7%	83.3%	0.0%	80.0%	36.8%	50.0%	52.1%
Under Construction	New Generation	1.0%	0.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.1%	2.2%	0.0%	0.0%	0.0%	0.0%	0.0%	1.0%	0.0%	1.9%
	Upgrade	0.9%	1.3%	1.2%	0.0%	0.0%	0.0%	0.0%	0.0%	1.6%	0.0%	0.0%	0.0%	5.8%	12.5%	0.0%	1.3%	0.0%	0.0%	0.0%	1.8%	0.0%	2.3%
Suspended	New Generation	2.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.2%	0.0%	1.8%
	Upgrade	2.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	5.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.5%	0.0%	1.7%
Withdrawn	New Generation	79.1%	85.9%	38.6%	47.6%	76.6%	93.3%	100.0%	82.8%	81.8%	72.5%	100.0%	22.5%	74.8%	85.2%	0.0%	87.3%	14.3%	0.0%	89.5%	80.4%	50.0%	76.5%
	Upgrade	81.4%	47.1%	14.9%	34.2%	70.6%	0.0%	0.0%	16.7%	24.6%	0.0%	50.0%	15.8%	41.9%	62.5%	0.0%	20.0%	16.7%	0.0%	20.0%	54.4%	50.0%	39.5%
Active	New Generation	6.6%	0.4%	1.2%	4.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	4.8%	9.3%	0.0%	0.0%	0.0%	0.0%	0.0%	1.0%	0.0%	3.5%
	Upgrade	7.1%	0.0%	2.4%	0.0%	0.0%	0.0%	0.0%	4.2%	0.0%	0.0%	0.0%	0.0%	12.7%	12.5%	0.0%	0.0%	0.0%	0.0%	0.0%	3.5%	0.0%	4.4%

Table 12-36 shows the total MW of projects in the PJM generation status queue by unit type and project classification. For example, the 488 new generation wind projects that have been withdrawn from the serial queue as of March 31, 2026, (as shown in Table 12-34) constitute 90,604.5 MW. The 440 new generation combined cycle projects that have been withdrawn in the same time period constitute 221,887.8 MW.

Table 12-36 Status of all generation (MW) in the generation serial queue: March 31, 2026

		Project MW																					
Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	312.5	39,701.9	6,734.4	676.5	149.2	1.5	0.0	371.5	1,639.0	170.8	0.0	440.1	12,399.2	22.1	0.0	1,343.0	728.0	0.0	60.9	10,829.1	186.0	75,765.7
	Upgrade	79.8	8,600.1	3,190.2	144.8	13.3	3.0	390.0	435.6	2,365.0	17.3	27.3	47.5	1,573.4	3.2	0.0	1,008.0	225.5	0.0	683.3	605.2	0.0	19,412.4
Under Construction	New Generation	340.0	2,065.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7,658.4	61.6	0.0	0.0	0.0	0.0	0.0	1,528.4	0.0	11,653.4
	Upgrade	50.0	198.8	90.0	0.0	0.0	0.0	0.0	0.0	44.0	0.0	0.0	0.0	465.4	100.0	0.0	36.0	0.0	0.0	0.0	105.9	0.0	1,090.1
Suspended	New Generation	536.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4,545.3	0.0	0.0	0.0	0.0	0.0	0.0	1,954.5	0.0	7,035.8
	Upgrade	102.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	306.5	0.0	0.0	0.0	0.0	0.0	0.0	107.3	0.0	516.0
Withdrawn	New Generation	7,383.0	221,887.8	5,794.3	1,735.0	1,248.0	6.4	1,200.0	2,105.9	8,161.0	481.2	63.9	88.6	60,545.4	11,899.2	0.0	33,511.6	27.0	0.0	1,050.9	90,604.5	90.0	447,883.6
	Upgrade	2,196.9	13,823.9	1,461.5	589.0	68.7	0.0	0.0	104.0	1,066.0	0.0	13.0	10.0	3,072.2	443.7	0.0	885.0	6.0	0.0	37.1	2,151.8	16.3	25,945.0
Active	New Generation	1,740.0	1,845.0	569.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9,656.0	1,633.6	0.0	0.0	0.0	0.0	0.0	1,427.7	0.0	16,921.2
	Upgrade	322.2	0.0	458.7	0.0	0.0	0.0	0.0	51.0	0.0	0.0	0.0	0.0	1,928.3	94.0	0.0	0.0	0.0	0.0	0.0	150.0	0.0	3,004.2
Total Projects	New Generation	10,311.5	265,499.7	13,097.7	2,461.5	1,397.2	7.9	1,200.0	2,477.4	9,800.0	652.0	63.9	528.7	94,804.3	13,616.4	0.0	34,854.6	755.0	0.0	1,111.8	106,344.1	276.0	559,259.7
	Upgrade	2,751.1	22,622.8	5,200.4	733.8	82.0	3.0	390.0	590.6	3,475.0	17.3	40.3	57.5	7,345.8	640.9	0.0	1,929.0	231.5	0.0	720.4	3,120.1	16.3	49,967.8

Table 12-37 shows the MW totals in Table 12-36 by share by classification as new generation or upgrade. Within a unit type the shares of upgrades add to 100 percent and the shares of new generation add to 100 percent. For example, 85.2 percent of wind project MW classified as new generation have been withdrawn from the serial queue between January 1, 1997, and March 31, 2026.

Table 12-37 Status of all generation serial queue projects as percent of total MW in project classification: March 31, 2026

		Percent of Total Projects by Classification																					
Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
	New Generation	3.0%	15.0%	51.4%	27.5%	10.7%	19.2%	0.0%	15.0%	16.7%	26.2%	0.0%	83.2%	13.1%	0.2%	0.0%	3.9%	96.4%	0.0%	5.5%	10.2%	67.4%	13.5%
In Service	Upgrade	2.9%	38.0%	61.3%	19.7%	16.2%	100.0%	100.0%	73.8%	68.1%	100.0%	67.7%	82.6%	21.4%	0.5%	0.0%	52.3%	97.4%	0.0%	94.9%	19.4%	0.0%	38.8%
	New Generation	3.3%	0.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	8.1%	0.5%	0.0%	0.0%	0.0%	0.0%	0.0%	1.4%	0.0%	2.1%
Under Construction	Upgrade	1.8%	0.9%	1.7%	0.0%	0.0%	0.0%	0.0%	0.0%	1.3%	0.0%	0.0%	0.0%	6.3%	15.6%	0.0%	1.9%	0.0%	0.0%	0.0%	3.4%	0.0%	2.2%
	New Generation	5.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	4.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.8%	0.0%	1.3%
Suspended	Upgrade	3.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	4.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.4%	0.0%	1.0%
	New Generation	71.6%	83.6%	44.2%	70.5%	89.3%	80.8%	100.0%	85.0%	83.3%	73.8%	100.0%	16.8%	63.9%	87.4%	0.0%	96.1%	3.6%	0.0%	94.5%	85.2%	32.6%	80.1%
Withdrawn	Upgrade	79.9%	61.1%	28.1%	80.3%	83.8%	0.0%	0.0%	17.6%	30.7%	0.0%	32.3%	17.4%	41.8%	69.2%	0.0%	45.9%	2.6%	0.0%	5.1%	69.0%	100.0%	51.9%
	New Generation	16.9%	0.7%	4.3%	2.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	10.2%	12.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.3%	0.0%	3.0%
Active	Upgrade	11.7%	0.0%	8.8%	0.0%	0.0%	0.0%	0.0%	8.6%	0.0%	0.0%	0.0%	0.0%	26.3%	14.7%	0.0%	0.0%	0.0%	0.0%	0.0%	4.8%	0.0%	6.0%

Table 12-38 shows the project MW that entered the PJM generation serial queue by unit type and year of entry. Since 2016, 82.5 percent of all new projects entering the generation serial queue have been combined cycle (19.5 percent), wind (17.2 percent) or solar projects (45.8 percent). Prior to 2015, no renewable hybrid units (solar + storage, solar + wind and wind + storage) entered the queue. In the time period from January 1, 2015, through June 10, 2023, 14,549.6 MW of renewable hybrid units have entered the serial queue.

Table 12-38 Serial queue project MW by unit type and queue entry year: March 31, 2026

Year	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
1997	0.0	4,148.0	321.0	315.0	0.0	0.0	0.0	0.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	6.0	0.0	0.0	0.0	0.0	0.0	4,840.0
1998	0.0	7,006.0	1,775.0	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	8,781.0
1999	0.0	29,412.7	2,069.1	0.0	10.0	0.0	0.0	196.0	45.0	0.0	0.0	0.0	0.0	0.0	0.0	47.0	0.0	0.0	525.0	115.4	0.0	32,420.2
2000	0.0	21,144.8	493.6	31.5	8.8	0.0	0.0	0.0	95.0	0.0	0.0	1.2	0.0	0.0	0.0	37.0	2.5	0.0	0.0	95.6	0.0	21,909.9
2001	0.0	25,411.7	264.0	0.0	0.0	0.0	0.0	107.0	90.0	0.0	0.0	15.6	0.0	0.0	0.0	1,244.6	10.0	0.0	0.0	234.9	0.0	27,377.8
2002	0.0	4,154.0	11.7	0.0	70.5	0.0	0.0	293.0	236.0	8.0	23.3	4.5	0.0	0.0	0.0	1,895.0	0.0	0.0	0.0	790.9	0.0	7,486.9
2003	0.0	2,361.4	10.0	8.0	0.8	0.0	0.0	2.0	0.0	29.0	0.0	27.5	0.0	0.0	0.0	522.0	0.0	0.0	165.0	997.0	0.0	4,122.7
2004	0.0	3,610.0	43.3	20.0	49.1	0.0	0.0	0.0	1,911.0	0.0	35.5	17.5	0.0	0.0	0.0	1,187.0	0.0	0.0	0.0	1,428.7	186.0	8,488.1
2005	0.0	5,824.6	961.0	281.0	51.4	0.0	340.0	174.2	242.0	21.5	0.0	65.1	0.0	0.0	0.0	6,360.0	0.0	0.0	24.0	6,015.4	0.0	20,360.3
2006	0.0	4,188.1	454.3	607.5	73.1	0.0	0.0	159.0	6,894.0	0.0	0.0	93.0	0.0	0.0	0.0	9,586.0	0.0	0.0	258.5	7,598.3	0.0	29,911.8
2007	0.0	13,926.6	941.2	215.9	149.5	0.0	16.0	209.6	368.0	0.0	0.0	56.5	3.3	0.0	0.0	9,078.0	190.0	0.0	68.5	18,508.5	0.0	43,731.5
2008	121.0	26,001.0	129.7	1,113.0	488.8	0.0	0.0	1,254.5	105.0	6.0	0.0	32.0	66.3	0.0	0.0	1,200.5	0.0	0.0	189.8	10,955.3	0.0	41,662.9
2009	34.0	5,548.4	14.0	66.0	214.2	0.0	0.0	133.9	1,933.8	4.5	16.0	15.2	636.5	0.0	0.0	1,273.0	5.5	0.0	148.0	6,672.6	0.0	16,715.6
2010	72.4	9,185.4	176.0	7.9	117.3	0.0	0.0	132.6	426.0	0.0	2.4	54.6	3,671.4	0.0	0.0	64.0	0.0	0.0	173.5	9,803.4	0.0	23,886.9
2011	24.1	19,744.0	29.5	0.0	172.5	0.0	0.0	30.0	182.0	0.0	14.0	75.3	2,014.0	0.0	0.0	357.0	0.0	0.0	49.0	5,576.4	0.0	28,267.8
2012	142.6	18,014.8	102.1	42.5	48.4	0.0	0.0	11.8	369.0	37.2	0.0	4.0	284.6	0.0	0.0	1,837.0	0.0	0.0	143.1	1,529.8	0.0	22,566.8
2013	217.4	10,493.1	1,201.8	5.0	11.2	0.0	0.0	89.4	102.0	59.7	0.0	1.6	231.7	0.0	0.0	158.0	40.0	0.0	44.7	1,296.6	0.0	13,952.1
2014	246.9	11,704.5	1,532.5	401.0	8.7	0.0	0.0	60.5	0.0	48.0	0.0	17.7	1,553.6	0.0	0.0	1,730.5	27.0	0.0	43.1	1,691.3	0.0	19,065.3
2015	546.9	27,550.8	1,324.5	0.0	0.9	2.3	34.0	0.0	0.0	320.4	13.0	31.4	2,919.3	3.4	0.0	47.0	606.5	0.0	0.0	2,160.6	0.0	35,560.9
2016	111.1	18,802.5	1,392.0	0.0	0.0	2.9	0.0	12.5	59.0	23.5	0.0	38.9	11,503.1	85.6	0.0	80.0	77.0	0.0	0.0	3,445.7	16.3	35,650.1
2017	24.6	5,477.6	691.0	0.0	4.1	2.7	0.0	20.5	39.1	97.1	0.0	33.8	13,686.8	324.9	0.0	14.0	17.0	0.0	0.0	5,137.0	90.0	25,660.3
2018	1,413.7	11,080.1	2,510.5	14.0	0.0	0.0	700.0	2.4	28.1	0.0	0.0	0.8	19,895.6	3,907.9	0.0	49.0	0.0	0.0	0.0	17,278.3	0.0	56,880.4
2019	4,192.8	3,332.5	1,003.7	13.0	0.0	3.0	500.0	99.0	0.0	14.4	0.0	0.0	25,384.3	4,625.3	0.0	11.0	0.0	0.0	0.0	6,036.1	0.0	45,215.1
2020	5,915.1	0.0	846.6	54.0	0.0	0.0	0.0	80.2	100.0	0.0	0.0	0.0	20,299.4	5,310.2	0.0	0.0	11.0	0.0	0.0	2,096.4	0.0	34,713.0
2021	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
2022	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
2023	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
2024	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
2025	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
Total	13,062.6	288,122.5	18,298.1	3,195.3	1,479.2	10.9	1,590.0	3,068.0	13,275.0	669.3	104.2	586.2	102,150.1	14,257.3	0.0	36,783.6	986.5	0.0	1,832.2	109,464.2	292.3	609,227.4

Combined Cycle Project Analysis

Table 12-39 shows the status of all combined cycle projects by number of projects that entered PJM generation serial queues from January 1, 1997, through July 10, 2023, by zone. Of the eight combined cycle projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation serial queue, three projects (37.5 percent) are located in the APS Zone.

Table 12-39 Status of all combined cycle serial queue projects by zone (number of projects): March 31, 2026

		Number of Projects																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	1	7	0	3	4	2	3	0	2	0	7	2	0	7	4	0	5	2	4	9	5	0	67
	Upgrade	3	15	0	10	5	0	6	0	0	0	16	5	0	6	5	0	13	3	4	12	14	0	117
Under Construction	New Generation	0	1	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3
	Upgrade	0	0	0	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	3
Suspended	New Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Withdrawn	New Generation	24	20	0	46	14	8	17	1	1	2	18	16	3	26	25	0	44	41	35	42	55	2	440
	Upgrade	7	10	0	11	4	0	4	0	1	0	11	6	0	8	7	0	3	7	5	8	15	0	107
Active	New Generation	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Projects	New Generation	25	29	0	51	19	10	20	1	3	2	25	18	3	33	29	0	49	43	39	51	60	2	512
	Upgrade	10	25	0	22	9	0	11	0	1	0	27	11	0	14	12	0	16	10	9	20	30	0	227

Table 12-40 shows the status of all combined cycle projects by MW that entered PJM generation serial queues from January 1, 1997, through July 10, 2023, by zone. Of the 4,108.8 MW of combined cycle projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 1,865.0 MW (45.4 percent) are located in the APS Zone.

Table 12-40 Status of all combined cycle serial queue projects by zone (MW): March 31, 2026

		Project MW																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	650.0	5,611.0	0.0	1,970.0	3,751.0	140.0	2,960.9	0.0	533.0	0.0	5,828.6	319.2	0.0	1,665.8	2,557.0	0.0	2,665.0	1,900.0	1,560.0	5,892.0	1,698.5	0.0	39,701.9
	Upgrade	229.0	1,300.0	0.0	959.7	344.0	0.0	642.6	0.0	0.0	0.0	1,035.0	102.0	0.0	110.0	188.9	0.0	1,075.5	112.3	228.6	1,426.6	845.9	0.0	8,600.1
Under Construction	New Generation	0.0	575.0	0.0	550.0	940.0	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	2,065.0
	Upgrade	0.0	0.0	0.0	45.0	0.0	0.0	102.7	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	51.1	0.0	198.8
Suspended	New Generation	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
	Upgrade	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
Withdrawn	New Generation	8,542.5	13,559.5	0.0	22,373.1	9,596.0	3,122.1	11,392.0	1,150.0	134.5	665.0	12,961.0	5,145.4	991.8	13,562.6	13,001.0	0.0	24,140.0	16,114.0	22,268.2	18,917.7	24,244.6	6.9	221,887.8
	Upgrade	156.9	1,031.0	0.0	1,368.0	636.0	0.0	1,735.0	0.0	36.0	0.0	780.4	1,410.0	0.0	413.0	1,742.0	0.0	240.0	1,125.6	229.1	703.0	2,217.9	0.0	13,823.9
Active	New Generation	0.0	575.0	0.0	1,270.0	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	1,845.0
	Upgrade	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
Total Projects	New Generation	9,192.5	20,320.5	0.0	26,163.1	14,287.0	3,262.1	14,352.9	1,150.0	667.5	665.0	18,789.6	5,464.6	991.8	15,228.4	15,558.0	0.0	26,805.0	18,014.0	23,828.2	24,809.7	25,943.1	6.9	265,499.7
	Upgrade	385.9	2,331.0	0.0	2,372.7	980.0	0.0	2,480.3	0.0	36.0	0.0	1,815.4	1,512.0	0.0	523.0	1,930.9	0.0	1,315.5	1,237.9	457.7	2,129.6	3,114.9	0.0	22,622.8

Of the eight combined cycle units in the serial queue as of March 31, 2026, in the status of active, under construction or suspended, one unit had a projected in service date prior to January 1, 2026 and seven units, representing 4,006.1 MW had a projected in service date between January 1, 2026, and December 31, 2029.

Combustion Turbine – Natural Gas Project Analysis

Table 12-41 shows the status of all combustion turbine natural gas projects by number of projects that entered PJM generation queues from January 1, 1997, through July 10, 2023, by zone. Of the seven combustion turbine natural gas projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation serial queue, four projects (57.1 percent) are located in the ATSI Zone.

Table 12-41 Status of all combustion turbine – natural gas generation serial queue projects by zone (number of projects): March 31, 2026

		Number of Projects																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	5	0	0	6	0	3	1	0	0	1	3	6	0	2	1	0	2	5	2	4	9	0	50
	Upgrade	4	11	0	10	5	0	20	6	0	0	28	8	0	5	5	0	4	8	5	4	14	0	137
Under Construction	New Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Upgrade	0	0	0	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2
Suspended	New Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Withdrawn	New Generation	2	6	0	0	0	2	1	1	0	0	4	0	1	1	0	0	1	6	0	1	6	0	32
	Upgrade	3	1	0	1	1	0	5	3	0	2	3	0	0	0	1	0	0	2	3	0	0	0	25
Active	New Generation	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	1
	Upgrade	0	0	0	0	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4
Total Projects	New Generation	7	6	0	6	0	5	2	1	0	1	8	6	1	3	1	0	3	11	2	5	15	0	83
	Upgrade	7	12	0	12	10	0	26	9	0	2	31	8	0	5	6	0	4	10	8	4	14	0	168

Table 12-42 shows the status of all combustion turbine natural gas projects by MW that entered PJM generation serial queues from January 1, 1997, through July 10, 2023, by zone. Of the 1,117.7 MW of combustion turbine natural gas projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation serial queue, 569.0 MW (50.9 percent) are located in the DOM Zone.

Table 12-42 Status of all combustion turbine – natural gas serial queue projects by zone (MW): March 31, 2026

		Project MW																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	360.7	0.0	0.0	1,184.0	0.0	23.0	190.0	0.0	0.0	205.0	1,081.0	1,140.0	0.0	520.0	10.0	0.0	559.0	379.9	5.0	150.9	925.9	0.0	6,734.4
	Upgrade	43.7	278.1	0.0	267.8	105.0	0.0	744.0	83.5	0.0	0.0	925.7	86.0	0.0	20.0	47.6	0.0	42.0	40.5	39.0	252.3	215.0	0.0	3,190.2
Under Construction	New Generation	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
	Upgrade	0.0	0.0	0.0	30.0	0.0	0.0	60.0	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	90.0
Suspended	New Generation	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
	Upgrade	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
Withdrawn	New Generation	237.5	1,519.0	0.0	0.0	0.0	153.6	10.0	104.0	0.0	0.0	1,069.8	0.0	73.0	2.1	0.0	0.0	0.5	789.8	0.0	19.9	1,815.1	0.0	5,794.3
	Upgrade	165.5	6.0	0.0	4.0	25.0	0.0	686.2	124.0	0.0	18.5	57.0	0.0	0.0	0.0	0.0	0.0	0.0	327.0	48.3	0.0	0.0	0.0	1,461.5
Active	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	569.0
	Upgrade	0.0	0.0	0.0	0.0	458.7	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	458.7
Total Projects	New Generation	598.2	1,519.0	0.0	1,184.0	0.0	176.6	200.0	104.0	0.0	205.0	2,719.8	1,140.0	73.0	522.1	10.0	0.0	559.5	1,169.7	5.0	170.8	2,741.0	0.0	13,097.7
	Upgrade	209.2	284.1	0.0	301.8	588.7	0.0	1,490.2	207.5	0.0	18.5	982.7	86.0	0.0	20.0	47.6	0.0	42.0	367.5	87.3	252.3	215.0	0.0	5,200.4

Of the seven combustion turbine natural gas units in the serial queue as of March 31, 2026, in the status of active, under construction or suspended, no units had a projected in service date prior to January 1, 2026, and seven units, representing 1,117.7 MW had a projected in service date between January 1, 2025, and December 31, 2031.

Wind Project Analysis

Table 12-43 shows the status of all wind generation projects, by number of projects that entered PJM generation serial queues from January 1, 1997, through July 10, 2023, by zone. Of the 24 wind projects classified as new generation or upgrade currently active, suspended or under construction in the PJM serial generation queue, 10 projects (41.7 percent) are located in the COMED Zone.

Table 12-43 Status of all wind generation serial queue projects by zone (number of projects): March 31, 2026

		Number of Projects																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	1	17	0	18	0	0	29	0	0	0	4	0	0	0	0	0	0	23	0	8	0	0	100
	Upgrade	0	3	0	3	0	0	9	0	0	0	0	0	0	0	0	0	0	6	0	0	0	0	21
Under Construction	New Generation	0	2	0	0	0	0	2	0	0	0	1	0	0	0	0	0	0	1	0	0	0	0	6
	Upgrade	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Suspended	New Generation	1	1	0	1	0	0	2	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	7
	Upgrade	0	1	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	2
Withdrawn	New Generation	23	121	0	46	10	0	116	15	0	0	22	14	1	6	0	0	0	63	0	50	1	0	488
	Upgrade	2	2	0	7	0	0	7	0	0	0	3	1	0	1	0	0	0	6	0	2	0	0	31
Active	New Generation	0	1	0	1	1	0	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6
	Upgrade	0	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2
Total Projects	New Generation	25	142	0	66	11	0	152	15	0	0	27	15	1	7	0	0	0	87	0	58	1	0	607
	Upgrade	2	6	0	10	0	0	19	0	0	0	3	2	0	1	0	0	0	12	0	2	0	0	57

Table 12-44 shows the status of all wind projects by MW that entered PJM generation serial queues from January 1, 1997, through July 10, 2023, by zone. Of the 5,273.7 MW of wind projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation serial queue, 2,384.6 MW (45.2 percent) are located in the COMED Zone.

Table 12-44 Status of all wind generation serial queue projects by zone (MW): March 31, 2026

		Project MW																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	7.5	3,223.0	0.0	1,232.9	0.0	0.0	4,586.7	0.0	0.0	0.0	511.5	0.0	0.0	0.0	0.0	0.0	0.0	1,041.0	0.0	226.5	0.0	0.0	10,829.1
	Upgrade	0.0	281.0	0.0	5.0	0.0	0.0	213.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	105.9	0.0	0.0	0.0	0.0	605.2
Under Construction	New Generation	0.0	340.3	0.0	0.0	0.0	0.0	1,000.0	0.0	0.0	0.0	78.2	0.0	0.0	0.0	0.0	0.0	0.0	109.9	0.0	0.0	0.0	0.0	1,528.4
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	105.9	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	105.9
Suspended	New Generation	432.0	100.0	0.0	80.0	0.0	0.0	278.7	0.0	0.0	0.0	0.0	247.8	0.0	816.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,954.5
	Upgrade	0.0	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	107.3
Withdrawn	New Generation	7,653.2	24,794.7	0.0	3,552.2	1,814.0	0.0	27,483.5	2,128.0	0.0	0.0	5,788.5	3,680.8	150.3	4,447.2	0.0	0.0	0.0	5,257.0	0.0	3,835.2	20.0	0.0	90,604.5
	Upgrade	5.0	370.0	0.0	119.4	0.0	0.0	754.0	0.0	0.0	0.0	114.0	30.0	0.0	510.0	0.0	0.0	0.0	243.4	0.0	6.0	0.0	0.0	2,151.8
Active	New Generation	0.0	200.0	0.0	80.0	297.7	0.0	850.0	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	1,427.7
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	150.0	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	150.0
Total Projects	New Generation	8,092.7	28,658.0	0.0	4,945.1	2,111.7	0.0	34,198.9	2,128.0	0.0	0.0	6,378.2	3,928.6	150.3	5,263.2	0.0	0.0	0.0	6,407.9	0.0	4,061.7	20.0	0.0	106,344.1
	Upgrade	5.0	751.0	0.0	124.4	0.0	0.0	1,223.1	0.0	0.0	0.0	114.0	37.3	0.0	510.0	0.0	0.0	0.0	349.3	0.0	6.0	0.0	0.0	3,120.1

Of the 24 wind units in the serial queue as of March 31, 2026, in the status of active, under construction or suspended, three units, representing 238.7 MW had a projected in service date prior to January 1, 2026 and 21 units, representing 5,035.1 MW had a projected in service date between January 1, 2025, and December 31, 2029.

A total of 48 offshore wind projects entered PJM generation serial queues from January 1, 1997, through July 10, 2023. Offshore wind projects are included in the wind generation statistics. Of the 24 wind projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation serial queue (Table 12-43), four projects (16.7 percent) are offshore wind. Of the 5,273.7 MW of wind projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation serial queue (Table 12-44), 1,503.1 MW (25.5 percent) are offshore wind projects. Table 12-43 shows that 519 wind projects have been withdrawn from the serial queue. Of those 519 wind projects, 43 projects (8.3 percent) were offshore wind. Table 12-44 shows that those 519 wind projects that have been withdrawn from the serial queue totaled 92,756.2 MW. Of the 92,756.2 MW of withdrawn wind projects, 16,787.2 MW (18.1 percent) were offshore wind projects.

Solar Project Analysis

Table 12-45 shows the status of all solar generation projects by number of projects that entered PJM generation serial queues from January 1, 1997, through July 10, 2023, by zone. Of the 299 solar projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation serial queue, 94 projects (31.4 percent) are located in the AEP Zone.

Table 12-45 Status of all solar generation serial queue projects by zone (number of projects): March 31, 2026

		Number of Projects																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	11	28	0	26	5	3	2	7	3	3	79	21	3	56	5	0	1	10	3	6	46	0	318
	Upgrade	2	9	0	6	2	0	1	4	3	1	26	12	2	13	0	0	0	1	0	3	4	0	89
Under Construction	New Generation	2	22	0	3	6	0	1	1	0	0	18	3	2	2	0	0	0	5	0	2	1	0	68
	Upgrade	0	2	0	0	1	0	0	0	0	0	6	2	1	1	0	0	0	2	0	0	0	0	15
Suspended	New Generation	1	15	1	8	3	0	1	1	1	0	10	4	0	1	2	0	0	9	2	5	0	0	64
	Upgrade	0	4	0	0	0	0	1	0	0	0	2	5	0	0	0	0	0	2	0	0	0	0	14
Withdrawn	New Generation	192	164	0	133	39	14	55	31	16	1	293	148	20	199	42	2	12	97	25	73	92	0	1,648
	Upgrade	4	13	0	10	4	0	7	2	0	0	33	4	1	9	2	0	0	9	3	5	3	0	109
Active	New Generation	0	41	0	5	5	0	6	5	1	0	15	1	3	3	1	0	0	11	0	8	0	0	105
	Upgrade	0	10	0	1	0	0	3	2	0	0	8	0	0	0	1	0	0	0	0	8	0	0	33
Total Projects	New Generation	206	270	1	175	58	17	65	45	21	4	415	177	28	261	50	2	13	132	30	94	139	0	2,203
	Upgrade	6	38	0	17	7	0	12	8	3	1	75	23	4	23	3	0	0	14	3	16	7	0	260

Table 12-46 shows the status of all solar projects by MW that entered PJM generation serial queues from January 1, 1997, through July 10, 2023, by zone. Of the 24,559.9 MW of solar projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation serial queue, 11,310.1 MW (46.1 percent) are located in the AEP Zone.

Table 12-46 Status of all solar generation serial queue projects by zone (MW): March 31, 2026

		Project MW																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	67.6	3,383.9	0.0	763.9	597.0	31.1	59.0	699.2	214.9	45.9	4,491.7	529.6	165.0	431.3	160.0	0.0	3.3	338.4	35.6	140.0	241.9	0.0	12,399.2
	Upgrade	0.0	557.0	0.0	60.0	60.0	0.0	50.0	144.8	85.0	8.3	492.8	39.8	40.0	21.9	0.0	0.0	0.0	0.0	0.0	10.0	3.8	0.0	1,573.4
Under Construction	New Generation	11.6	3,347.1	0.0	230.0	328.0	0.0	116.0	300.0	0.0	0.0	2,478.4	257.0	130.0	30.8	0.0	0.0	0.0	263.5	0.0	160.0	6.0	0.0	7,658.4
	Upgrade	0.0	110.0	0.0	0.0	56.0	0.0	0.0	0.0	0.0	0.0	159.9	40.0	40.0	11.0	0.0	0.0	0.0	48.5	0.0	0.0	0.0	0.0	465.4
Suspended	New Generation	149.3	1,750.1	40.0	314.8	212.9	0.0	210.0	40.0	100.0	0.0	996.9	207.6	0.0	7.0	149.6	0.0	0.0	230.1	40.0	97.0	0.0	0.0	4,545.3
	Upgrade	0.0	79.0	0.0	0.0	0.0	0.0	50.0	0.0	0.0	0.0	53.0	94.5	0.0	0.0	0.0	0.0	0.0	30.0	0.0	0.0	0.0	0.0	306.5
Withdrawn	New Generation	2,300.4	12,798.9	0.0	3,775.6	2,259.2	112.3	4,217.1	2,215.5	689.4	20.0	19,157.0	2,564.4	1,266.9	1,641.3	1,249.7	198.0	124.2	3,186.6	283.9	1,894.9	590.2	0.0	60,545.4
	Upgrade	172.5	473.0	0.0	140.7	279.7	0.0	185.0	62.0	0.0	0.0	1,337.6	52.0	70.0	23.8	40.0	0.0	0.0	90.0	3.6	141.0	1.3	0.0	3,072.2
Active	New Generation	0.0	4,966.4	0.0	482.6	714.0	0.0	554.9	407.8	49.0	0.0	1,437.4	4.0	211.0	51.6	55.0	0.0	0.0	526.8	0.0	195.5	0.0	0.0	9,656.0
	Upgrade	0.0	1,057.5	0.0	78.4	0.0	0.0	190.0	58.5	0.0	0.0	368.0	0.0	0.0	0.0	20.0	0.0	0.0	0.0	0.0	155.9	0.0	0.0	1,928.3
Total Projects	New Generation	2,528.9	26,246.4	40.0	5,566.9	4,111.1	143.4	5,157.0	3,662.5	1,053.3	65.9	28,561.4	3,562.6	1,772.9	2,162.0	1,614.3	198.0	127.5	4,545.4	359.5	2,487.4	838.1	0.0	94,804.3
	Upgrade	172.5	2,276.5	0.0	279.1	395.7	0.0	475.0	265.3	85.0	8.3	2,411.3	226.3	150.0	56.7	60.0	0.0	0.0	168.5	3.6	306.9	5.1	0.0	7,345.8

Of the 299 solar units in the serial queue as of March 31, 2026, in the status of active, under construction or suspended, 40 units, representing 2,422.6 MW had a projected in service date prior to January 1, 2026 and 259 units, representing 22,137.3 MW had a projected in service date between January 1, 2025, and December 31, 2031.

Battery Project Analysis

Table 12-47 shows the status of all battery generation projects by number of projects that entered PJM generation serial queues from January 1, 1997, through July 10, 2023, by zone. Of the 43 battery projects currently active, suspended or under construction in the PJM generation serial queue, 12 projects (27.9 percent) are located in the AEP Zone.

Table 12-47 Status of all battery generation serial queue projects by zone (number of projects): March 31, 2026

		Number of Projects																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	0	3	0	2	0	2	7	1	4	0	2	0	0	7	0	0	1	0	0	1	2	0	32
	Upgrade	0	1	0	1	0	0	0	1	1	0	0	0	0	3	0	0	0	2	0	0	0	0	9
Under Construction	New Generation	0	0	0	0	0	0	0	0	0	0	2	0	0	1	0	0	0	0	0	0	0	0	3
	Upgrade	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	1
Suspended	New Generation	0	4	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	1	0	2	0	0	8
	Upgrade	0	1	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	3
Withdrawn	New Generation	12	29	0	5	6	27	21	1	3	2	29	25	2	40	6	0	4	6	2	10	9	0	239
	Upgrade	7	13	0	11	1	0	6	2	1	0	18	3	1	7	4	0	3	11	0	4	0	0	92
Active	New Generation	2	6	0	0	0	0	1	1	0	0	3	0	0	3	0	0	0	0	0	0	4	0	20
	Upgrade	0	1	0	1	0	0	3	1	0	0	1	0	0	0	1	0	0	0	0	0	0	0	8
Total Projects	New Generation	14	42	0	7	6	29	29	3	7	2	36	26	2	51	6	0	5	7	2	13	15	0	302
	Upgrade	7	16	0	13	1	0	10	4	3	0	20	3	1	10	5	0	3	13	0	4	0	0	113

Table 12-48 shows the status of all battery projects by MW that entered PJM generation serial queues from January 1, 1997, through July 10, 2023, by zone. Of the 3,090.4 MW of battery generation currently active, suspended or under construction in the PJM generation serial queue, 819.2 MW (26.5 percent) are located in the AEP Zone.

Table 12-48 Status of all battery generation serial queue projects by zone (MW): March 31, 2026

		Project MW																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	0.0	10.0	0.0	12.5	0.0	3.5	86.0	12.0	16.0	0.0	35.7	0.0	0.0	112.8	0.0	0.0	1.0	0.0	0.0	20.0	3.0	0.0	312.5
	Upgrade	0.0	4.0	0.0	27.4	0.0	0.0	0.0	8.0	4.0	0.0	0.0	0.0	0.0	8.0	0.0	0.0	0.0	28.4	0.0	0.0	0.0	0.0	79.8
Under Construction	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	320.0	0.0	0.0	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	340.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50.0
Suspended	New Generation	0.0	197.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.0	0.0	0.0	0.0	0.0	0.0	160.0	0.0	170.0	0.0	0.0	536.0
	Upgrade	0.0	40.0	0.0	0.0	0.0	0.0	10.0	0.0	52.2	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	102.2
Withdrawn	New Generation	303.0	1,047.4	0.0	237.0	106.1	580.6	387.0	19.9	75.5	75.0	1,190.4	600.5	46.3	976.1	395.9	0.0	4.3	470.8	21.0	424.8	421.5	0.0	7,383.0
	Upgrade	20.0	769.2	0.0	219.0	20.3	0.0	125.3	95.0	20.0	0.0	441.0	54.0	28.0	55.1	174.0	0.0	60.0	76.0	0.0	40.0	0.0	0.0	2,196.9
Active	New Generation	50.0	530.0	0.0	0.0	0.0	0.0	20.0	85.0	0.0	0.0	240.0	0.0	0.0	290.0	0.0	0.0	0.0	0.0	0.0	0.0	525.0	0.0	1,740.0
	Upgrade	0.0	52.2	0.0	20.0	0.0	0.0	150.0	40.0	0.0	0.0	40.0	0.0	0.0	0.0	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	322.2
Total Projects	New Generation	353.0	1,784.4	0.0	249.5	106.1	584.1	493.0	116.9	91.5	75.0	1,786.1	609.5	46.3	1,398.9	395.9	0.0	5.3	630.8	21.0	614.8	949.5	0.0	10,311.5
	Upgrade	20.0	865.4	0.0	266.4	20.3	0.0	285.3	143.0	76.2	0.0	531.0	54.0	28.0	63.1	194.0	0.0	60.0	104.4	0.0	40.0	0.0	0.0	2,751.1

Of the 43 battery units in the serial queue as of March 31, 2026, in the status of active, under construction or suspended, four units, representing 142.2 MW had a projected in service date prior to January 1, 2026, and 39 units, representing 2,948.2 MW had a projected in service date between January 1, 2025, and December 31, 2030.

Renewable Hybrid Project Analysis

Table 12-49 shows the status of all renewable hybrid generation projects (solar + storage, solar + wind and wind + storage) by number of projects that entered PJM generation serial queues from January 1, 1997, through July 10, 2023, by zone.[81] Of the 23 renewable hybrid projects currently active, suspended or under construction in the PJM generation serial queue, five projects (21.7 percent) are located in the DOM Zone, and five projects (21.7 percent) are located in the AEP Zone.

81 PJM does not currently have a definition of a hybrid resource.

Table 12-49 Status of all renewable hybrid generation serial queue projects by zone (number of projects): March 31, 2026

		Number of Projects																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	0	0	0	1	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	5	0	7
	Upgrade	0	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2
Under Construction	New Generation	0	0	0	0	3	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	4
	Upgrade	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Suspended	New Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Withdrawn	New Generation	6	17	0	13	7	0	7	0	0	2	37	1	9	4	11	0	0	12	1	20	9	0	156
	Upgrade	0	1	0	2	0	0	0	0	0	0	1	0	0	0	1	0	0	0	0	1	0	0	6
Active	New Generation	1	4	0	2	0	0	1	0	0	0	4	2	0	1	0	0	0	0	0	2	0	0	17
	Upgrade	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	1
Total Projects	New Generation	7	21	0	16	10	0	8	0	0	2	42	4	9	5	11	0	0	12	1	22	14	0	184
	Upgrade	0	3	0	2	0	0	1	0	0	0	2	0	0	0	1	0	0	0	0	1	0	0	10

Table 12-50 shows the status of all renewable hybrid projects by MW that entered PJM generation serial queues from January 1, 1997, through July 10, 2023, by zone. Of the 1,889.2 MW of renewable hybrid generation currently active, suspended or under construction in the PJM generation serial queue, 659.0 MW (34.9 percent) are located in the AEP Zone.

Table 12-50 Status of all renewable hybrid generation serial queue projects by zone (MW): March 31, 2026

		Project MW																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	0.0	0.0	0.0	186.0	0.0	0.0	0.0	0.0	0.0	0.0	17.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.1	0.0	208.1
	Upgrade	0.0	3.2	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	3.2
Under Construction	New Generation	0.0	0.0	0.0	0.0	57.7	0.0	0.0	0.0	0.0	0.0	0.0	3.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	61.6
	Upgrade	0.0	100.0	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	100.0
Suspended	New Generation	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
	Upgrade	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
Withdrawn	New Generation	114.5	4,703.8	0.0	460.5	659.9	0.0	1,004.9	0.0	0.0	37.5	2,799.2	10.0	1,252.0	110.0	97.1	0.0	0.0	475.0	20.0	195.0	49.9	0.0	11,989.2
	Upgrade	0.0	400.0	0.0	16.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.7	0.0	0.0	0.0	0.0	40.0	0.0	0.0	460.0
Active	New Generation	38.0	559.0	0.0	380.0	0.0	0.0	19.9	0.0	0.0	0.0	494.0	12.7	0.0	70.0	0.0	0.0	0.0	0.0	0.0	60.0	0.0	0.0	1,633.6
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	94.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	94.0
Total Projects	New Generation	152.5	5,262.8	0.0	1,026.5	717.6	0.0	1,024.8	0.0	0.0	37.5	3,310.2	26.5	1,252.0	180.0	97.1	0.0	0.0	475.0	20.0	255.0	54.9	0.0	13,892.4
	Upgrade	0.0	503.2	0.0	16.3	0.0	0.0	0.0	0.0	0.0	0.0	94.0	0.0	0.0	0.0	3.7	0.0	0.0	0.0	0.0	40.0	0.0	0.0	657.2

Of the 23 renewable hybrid units in the serial queue as of March 31, 2026, in the status of active, under construction or suspended, two units, representing 6.6 MW had a projected in service date prior to January 1, 2026, and 21 units, representing 1,882.6 MW had a projected in service date between January 1, 2025, and December 31, 2031.

New Service Requests Cycle Process[82]

Interconnection Process Studies and Agreements

The transition to the new queue process began on July 10, 2023. The new queue process includes modifications to implement a cluster/cycle based processing method to replace the first in/first out processing method.[83] Each cycle consists of the: application phase, phase I, decision point I, phase II, decision point II, phase III, decision point III, and the final agreement negotiation phase.

Application Phase

The application phase includes the submission and review of a new service request. A new service request could be a request to interconnect a new generating facility, a request to increase the capability of an existing generating facility, a request to interconnect a merchant transmission facility, a request to increase the capability of an existing merchant transmission facility, a request to interconnect a generating facility to distribution facilities located in PJM that are to be used for transmission of power in interstate commerce, and to make wholesale sales or a long term firm transmission service request outside of the 18 month available transfer capability (ATC) horizon. The deadline for submitting applications for a new cycle corresponds with the completion of phase II of the previous cycle. For an application to be considered complete, and included in a cycle, PJM must receive a completed and executed application and studies agreement (ASA), required technical information, a wire transfer for the entirety of study deposit, a wire transfer or letter of credit for the entirety of Readiness Deposit No. 1 and, for generation requests, evidence of site control.

Phase I

Phase I of a cycle begins after the application phase of a cycle is completed and a group of valid new service requests is established. During phase I of a cycle, PJM performs a phase I system impact study (SIS). The phase I SIS is conducted on an aggregate basis within a cycle, and results are provided in a single cycle format. The phase I SIS results are posted on PJM's website. The phase I SIS evaluates each new service request on a summer peak, winter peak and light load RTEP base case. PJM only performs a load flow analysis during the phase I system impact study. In phase I of the cycle, PJM also conducts an affected system screen and provides each affected system operator with a list of new service requests within the cycle including potential impacts to their system. During phase I, PJM creates both the short circuit and stability base cases that will be used in the phase II SIS.

Decision Point I

New service requests that are studied in phase I will enter decision point I. After reviewing the results of the phase I SIS, the project developer must decide whether or not to move forward to phase II of the process. Decision point I starts on the first business day following the end of phase I and closes 30 calendar days later. Before the close of decision point I, the project developer can choose to either remain in the cycle by meeting the decision point I requirements or to withdraw its new service request. If a project developer fails to submit all required deposits, evidence, and data before the close of decision point I, the new service request will be terminated and withdrawn.

Phase II

After the decision point I phase of a cycle is completed and a group of valid new service requests is established, phase II of a cycle will begin. During phase II of a cycle, PJM performs the phase II SIS. PJM retools the load flow results from the phase I SIS (summer peak, winter peak and light load) based on decisions made during decision point I. PJM also conducts any required voltage analyses, performs short circuit and stability analyses and coordinates with affected systems to confirm which projects in the cycle will require affected system studies. If the affected system operator indicates that an affected system study is required, PJM notifies the project developer of the need for an affected system study and the requirement to execute an affected system study agreement with the impacted affected system operator. If applicable and available, PJM includes the results of the affected system operator's affected system study in the phase II SIS results.

The phase II SIS includes a facilities study by the affected transmission owner that identifies any required network upgrades. The facilities studies will

82 Material in this section is based on information found in PJM Manual 14H. See "PJM Manual 14H: New Service Requests Cycle Process," Rev. 03 (September 25, 2025).

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

include good faith estimates of the costs to be charged to each affected new service customer for the network upgrades that are necessary to accommodate each new service request evaluated in the study, the time required to complete detailed design and construction of the facilities and upgrades and a description of any site-specific environmental issues or requirements that could reasonably be anticipated to affect the cost or time required to complete construction of such facilities and upgrades.

Decision Point II

New service requests that are studied in phase II will enter decision point II. After reviewing the results of the phase II SIS, the project developer must decide whether or not to move forward to phase III of the process. Decision point II starts on the first business day following the end of phase II and closes 30 calendar days later. Before the close of decision point II, the project developer can choose to either remain in the cycle by meeting the decision point II requirements or to withdraw its new service request. If a project developer fails to submit all required deposits, evidence, and data before the close of decision point II, the new service request will be terminated and withdrawn.

Phase III

After the decision point II phase of a cycle is completed and a group of valid new service requests is established, phase III of a cycle will begin. During phase III of a cycle, PJM performs the phase III SIS. PJM retools the load flow, short circuit and stability results from the phase II SIS based on decisions made during decision point II. PJM also coordinates with affected systems to conduct any studies required to determine the final impact of a new service request on any affected system. If applicable and available, PJM includes the results of the affected system operator's final affected system study in the phase III SIS results.

Decision Point III

New service requests that are studied in phase III will enter decision point III. After reviewing the results of the phase III SIS, the project developer must decide whether or not to move forward to the final agreement negotiation phase. Decision point III starts on the first business day following the end of phase III and runs concurrently with the final agreement negotiation phase. The project developer can choose to either remain in the cycle by meeting the decision point III requirements or to withdraw its new service request. If a project developer fails to submit all required deposits, evidence, and data before the close of decision point III, the new service request will be terminated and withdrawn.

Final Agreement Negotiation Phase

The final agreement negotiation phase starts on the first business day immediately following the end of phase III, and runs concurrently with decision point III. The purpose of the final agreement negotiation phase is to negotiate, execute and enter into the applicable final interconnection related service agreement, conduct any remaining analyses or updated analyses based on new service requests withdrawn during decision point III and adjust the security obligation based on new service requests withdrawn during decision point III and/or during the final agreement negotiation phase. PJM uses reasonable efforts to complete the final agreement negotiation phase within 60 days. Table 12-51 is an overview of the agreements used in the new service requests cycle process.

Table 12-51 Final agreements: new service requests cycle process

Agreement	Purpose
Generation Interconnection Agreement (GIA)	The GIA defines the obligations of the project developer regarding cost responsibility for any required system upgrades. The GIA also confers the rights associated with the interconnection of a generating facility as a capacity resource and any operational restrictions or other limitations on which those rights depend. For transmission project developers, the GIA confers transmission injection and withdrawal rights and applicable incremental delivery rights and incremental auction revenue rights.The GIA further identifies any changes in construction responsibility from the standard option for transmission owner interconnection facilities due to the project developer exercising the negotiated contract option or option to build.
Construction Service Agreement (CSA)	The CSA defines the standard terms and conditions of the interconnection, including construction responsibility, includes a construction schedule and contains notification and insurance obligations.The CSA is included as a schedule within a GIA; however, a stand-alone CSA may be implemented in circumstances in which network upgrades to the system of a transmission owner are required to accommodate the interconnection request of a project developer, whose facilities do not directly interconnect to the transmission owner's system. Examples include project developers who are affected system customers (external to the PJM region), that require network upgrades to be constructed by PJM transmission owners, or project developers requiring upgrades to be constructed by PJM transmission owners, other than their interconnecting transmission owner
Upgrade Construction Service Agreement (USCA)	A new service customer who proposes to make an upgrade to an existing transmission facility or who seeks incremental auction revenue rights (IARRs) will receive an upgrade construction service agreement after their study process is completed.
Network Upgrade Cost Responsibility Agreement (NUCRA)	The NUCRA refers to the agreement entered into by two or more project developers and PJM, relating to construction of common use upgrades (network upgrades needed for the interconnection of generating or merchant transmission facilities for more than one project developer that share cost responsibility) and coordination of the construction and interconnection of associated generating facilities. A separate NUCRA will be executed for each set of common use upgrades on the system of a specific transmission owner that is associated with the interconnection of a generating facility or merchant transmission facility. The NUCRA includes the identified common use upgrades scope and schedule of work, the cost responsibility for the project developers that share cost responsibility, as well as the terms and conditions for the agreement.
Wholesale Market Participation Agreement (WMPA)	Developers interconnecting to non-FERC jurisdictional facilities who intend to participate in the PJM wholesale market will receive a three party agreement (WMPA). The WMPA is a non-Tariff agreement which must be filed with the FERC. The WMPA is essentially an ISA without interconnection provisions.

Transition Cycle 1 (TC1)

On November 29, 2022, the Commission issued an order accepting PJM's tariff revisions to improve the queue process.[84] The new queue process includes modifications to implement a cluster/cycle based processing method to replace the first in/first out processing method.[85] 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.

On May 20, 2024, PJM completed the phase I system impact study for transition cycle 1 (TC1). Developers had 30 days (until June 20, 2024) to decide whether to proceed with their new service requests into the next study phase of TC1 or to withdraw their projects. Continuing with phase II required developers to meet the decision point I requirements (including additional readiness deposits and proof of site control).[86]

84 181 FERC ¶ 61,162 (2022).
85 See "Interconnection Process Reform," presented at April 27, 2022 Members Committee meeting. <https://www.pjm.com/-/media/committees-groups/committees/mc/2022/20220427/20220427-item-01a-1-interconnection-process-reform-presentation.ashx>.
86 See "PJM Manual 14H: New Service Requests Cycle Process," Rev. 03 (September 25, 2025) for a complete list of all readiness requirements.

On December 20, 2024, PJM completed the phase II system impact study for TC1. Developers had 30 days (until January 19, 2025) to decide whether to proceed with their new service requests into the next study phase of TC1 or to withdraw their projects. Continuing with phase III requires developers to meet the decision point II requirements, (including additional readiness deposits and proof of site control).[87]

On April 21, 2025, phase III of TC1 began. During phase III, PJM performed the phase III SIS. PJM retooled the load flow, short circuit and stability results from the phase II SIS based on decisions made during decision point II. PJM also coordinated with affected systems to conduct any studies required to determine the final impact of a new service request on any affected system. Phase III of TC1 completed on September 19, 2025. The TC1 decision point III ran for 30 days, and completed on October 21, 2025. Additionally, the TC1 final agreement phase also began at the completion of phase III, and completed on November 20, 2025.

87 See "PJM Manual 14H: New Service Requests Cycle Process," Rev. 03 (September 25, 2025) for a complete list of all readiness requirements.

Planned Generation Additions

TC1 is comprised of 312 proposed generation projects. Those projects make up 40,650.1 MW. On March 31, 2026, all projects in TC1 were either in the status of active, under construction or were withdrawn from the cycle. Table 12-52 shows each status by unit type. Of the 40,650.1 MW in TC1, 14,120.0 MW (34.7 percent) were active or under construction (10,763.0 MW (26.5 percent) were active and 3,357.0 MW (8.2 percent) were under construction) and 26,530.1 MW (65.3 percent) were withdrawn. Of the 10,763.0 MW in the status of active, 7,336.2 MW (68.2 percent) were solar projects, 1,245.9 MW (11.6 percent) were wind projects, and 1,330.0 MW (12.4 percent) were battery projects.

Table 12-52 Transition cycle 1 project status (MW) by unit type: March 31, 2026

	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
Active	1,330.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7,336.2	851.0	0.0	0.0	0.0	0.0	0.0	1,245.9	0.0	10,763.0
Under Construction	75.0	0.0	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	224.0	0.0	0.0	0.0	0.0	0.0	0.0	2,489.0	0.0	3,357.0
Withdrawn	4,877.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13,369.8	3,257.2	199.0	0.0	0.0	0.0	0.0	4,826.7	0.0	26,530.1
Total	6,282.4	0.0	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20,930.0	4,108.2	199.0	0.0	0.0	0.0	0.0	8,561.6	0.0	40,650.1

Table 12-53 shows the projects in TC1 with a status of active or under construction, by unit type, and control zone. As of March 31, 2026, 14,120.0 MW were in TC1 for construction through 2031. Table 12-53 also shows the planned retirements for each zone.

Table 12-53 Transition cycle 1 totals for projects (active and under construction) by LDA, control zone and unit type (MW): March 31, 2026

LDA	Zone	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total Queue Capacity	Planned Retirements
EMAAC	ACEC	70.0	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	70.0	175.1
	DPL	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	16.4
	JCPLC	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	65.0
	PECO	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	760.0
	PSEG	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	2.0
	REC	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
	EMAAC Total	70.0	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	70.0	1,018.5
SWMAAC	BGE	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	1,975.0
	PEPCO	500.0	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	500.0	0.0
	SWMAAC Total	500.0	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	500.0	1,975.0
WMAAC	MEC	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
	PE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	110.0	245.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	355.0	10.4
	PPL	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
	WMAAC Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	110.0	245.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	355.0	10.4
Non-MAAC	AEP	255.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,115.0	500.0	0.0	0.0	0.0	0.0	0.0	755.0	0.0	2,625.0	2,620.0
	AMPT	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
	APS	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	31.5
	ATSI	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12.0	0.0
	COMED	330.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,853.1	0.0	0.0	0.0	0.0	0.0	0.0	490.9	0.0	4,674.0	2,671.9
	DAY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	206.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	206.6	0.0
	DUKE	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	10.0
	DLCO	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
	DOM	250.0	0.0	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,439.0	0.0	0.0	0.0	0.0	0.0	0.0	2,489.0	0.0	4,747.0	2.0
	EKPC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	824.5	106.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	930.5	116.0
	OVEC	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
	RMU	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-MAAC Total	835.0	0.0	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7,450.2	606.0	0.0	0.0	0.0	0.0	0.0	3,734.9	0.0	13,195.0	5,451.4
Total		1,405.0	0.0	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7,560.2	851.0	0.0	0.0	0.0	0.0	0.0	3,734.9	0.0	14,120.0	8,455.3

Table 12-54 shows that on March 31, 2026, there were 14,120.0 MW, on an energy basis, of which 6,798.9 MW are on a capacity basis that requested CIRs, in TC1 in the status of active or under construction. Table 12-54 also shows the total capacity MW adjusted for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.

Of the 6,798.9 MW, on a capacity basis that requested CIRs in TC1 in the status of active or under construction, 1,741.7 MW (25.6 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.

Of the 569.0 MW, on a capacity basis that requested CIRs, of thermal projects (including CT natural gas projects) requested in TC1 in the status of active or under construction, 381.2 MW (67.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.

Of the 3,727.4 MW, on a capacity basis that requested CIRs, of solar projects requested in TC1 in the status of active or under construction, 372.7 MW (10.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.

Of the 1,022.0 MW, on a capacity basis that requested CIRs, of battery projects requested in TC1 in the status of active or under construction, 603.0 MW (59.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.

Of the 5,207.9 MW, on a capacity basis that requested CIRs, of renewable projects requested in TC1 in the status of active or under construction, 757.5 MW (14.5 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.

Table 12-54 Transition cycle 1 totals for projects (active and under construction) by unit type adjusted for ELCC derates (MW): March 31, 2026

	Energy (MW)		Capacity (MW)
Unit Type	Total	Total	ELCC Adjusted
Battery	1,405.0	1,022.0	603.0
CC	0.0	0.0	0.0
CT - Natural Gas	569.0	569.0	381.2
CT - Oil	0.0	0.0	0.0
CT - Other	0.0	0.0	0.0
Fuel Cell	0.0	0.0	0.0
Hydro - Pumped Storage	0.0	0.0	0.0
Hydro - Run of River	0.0	0.0	0.0
Nuclear	0.0	0.0	0.0
RICE - Natural Gas	0.0	0.0	0.0
RICE - Oil	0.0	0.0	0.0
RICE - Other	0.0	0.0	0.0
Solar	7,560.2	3,727.4	372.7
Solar + Storage	851.0	494.3	49.4
Solar + Wind	0.0	0.0	0.0
Steam - Coal	0.0	0.0	0.0
Steam - Natural Gas	0.0	0.0	0.0
Steam - Oil	0.0	0.0	0.0
Steam - Other	0.0	0.0	0.0
Wind	3,734.9	986.3	335.3
Wind + Storage	0.0	0.0	0.0
Total	14,120.0	6,798.9	1,741.7

Withdrawn Projects

Table 12-55 shows the status of all TC1 projects as they have progressed through the cycle process. Of the 312 projects included in TC1, 121 projects (38.8 percent of all projects and 38.9 percent of the total MW) were withdrawn during phase I or decision point I, 63 projects (20.2 percent of all projects and 17.4 percent of the total MW) were withdrawn during phase II or decision point II, 40 projects (12.8 percent of all projects and 7.1 percent of the total MW) were withdrawn during phase III or decision point III and 5 projects (1.6 percent of all projects and 1.9 percent of the total MW) were withdrawn during the final agreement stage. On March 31, 2026, 83 projects (26.6 percent of all projects and 34.7 percent of the total MW) remain active, have reached the final agreement stage or are under construction in TC1.

Table 12-55 Transition cycle 1 status: March 31, 2026

	Number of Projects	Percent of Projects	MW Energy	Percent of MW Energy
Transition cycle 1 approved projects	312	100.0%	40,650.1	100.0%
Withdrawn prior to start of phase I	0	0.0%	0.0	0.0%
Withdrawn during phase I or decision point I	121	38.8%	15,821.8	38.9%
Withdrawn during phase II or decision point II	63	20.2%	7,067.5	17.4%
Withdrawn during phase III or decision point III	40	12.8%	2,886.5	7.1%
Withdrawn during final agreement stage	5	1.6%	754.2	1.9%
Active as of March 31, 2026	5	1.6%	536.0	1.3%
In final agreement stage as of March 31, 2026	69	22.1%	10,227.0	25.2%
Under construction	9	2.9%	3,357.0	8.3%
In Service	0	0.0%	0.0	0.0%

Table 12-56 shows 40,650.1 MW have entered TC1. Table 12-56 presents totals by fuel type and projected in service date as of March 31, 2026. Of the 40,650.1 MW to enter TC1, 569.0 MW (1.4 percent) were thermal units.

Table 12-56 Transition cycle 1 total (MW Energy) by unit type and projected in service year: March 31, 2026

Year	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
2018	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	90.0	0.0	0.0	0.0	0.0	0.0	0.0	255.0	0.0	345.0
2019	831.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,750.3	1,826.8	0.0	0.0	0.0	0.0	0.0	2,112.2	0.0	7,520.9
2020	4,045.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10,529.6	1,430.4	199.0	0.0	0.0	0.0	0.0	2,459.6	0.0	18,664.2
2021	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
2022	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	216.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	216.0
2023	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.0
2024	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
2025	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
2026	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
2027	55.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	125.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	180.0
2028	70.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	277.1	106.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	453.1
2029	200.0	0.0	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,587.5	745.0	0.0	0.0	0.0	0.0	0.0	1,045.9	0.0	5,147.4
2030	830.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,483.6	0.0	0.0	0.0	0.0	0.0	0.0	200.0	0.0	3,513.6
2031	250.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,351.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,601.0
2032	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	500.0	0.0	0.0	0.0	0.0	0.0	0.0	2,489.0	0.0	2,989.0
Total	6,282.4	0.0	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20,930.0	4,108.2	199.0	0.0	0.0	0.0	0.0	8,561.6	0.0	40,650.1

Table 12-57 shows there were 14,120.0 MW in TC1 in the status of active or under construction as of March 31, 2026. Table 12-57 presents totals by fuel type and projected in service date. Of the 14,120.0 MW, 569.0 MW (4.0 percent) are thermal units.

Table 12-57 Transition cycle 1 total (MW Energy) by unit type and projected in service year (active and under construction): March 31, 2026

Year	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
2018	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
2019	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
2020	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
2021	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
2022	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	216.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	216.0
2023	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.0
2024	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
2025	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
2026	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
2027	55.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	125.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	180.0
2028	70.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	277.1	106.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	453.1
2029	200.0	0.0	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,587.5	745.0	0.0	0.0	0.0	0.0	0.0	1,045.9	0.0	5,147.4
2030	830.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,483.6	0.0	0.0	0.0	0.0	0.0	0.0	200.0	0.0	3,513.6
2031	250.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,351.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,601.0
2032	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	500.0	0.0	0.0	0.0	0.0	0.0	0.0	2,489.0	0.0	2,989.0
Total	1,405.0	0.0	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7,560.2	851.0	0.0	0.0	0.0	0.0	0.0	3,734.9	0.0	14,120.0

Table 12-58 shows there were 26,530.1 MW withdrawn from TC1. Table 12-58 presents totals by fuel type and projected in service date. Of the 26,530.1 MW withdrawn from TC1, none were identified as thermal units.

Table 12-58 Transition cycle 1 total (MW Energy) by unit type and projected in service year (withdrawn): March 31, 2026

Year	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
2018	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	90.0	0.0	0.0	0.0	0.0	0.0	0.0	255.0	0.0	345.0
2019	831.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,750.3	1,826.8	0.0	0.0	0.0	0.0	0.0	2,112.2	0.0	7,520.9
2020	4,045.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10,529.6	1,430.4	199.0	0.0	0.0	0.0	0.0	2,459.6	0.0	18,664.2
2021	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
2022	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
2023	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
2024	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
2025	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
2026	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
2027	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
2028	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
2029	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
2030	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
2031	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
2032	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
Total	4,877.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13,369.8	3,257.2	199.0	0.0	0.0	0.0	0.0	4,826.7	0.0	26,530.1

Analysis by Fuel Group

Table 12-59 shows the number of projects that entered TC1 by year and by fuel group. The fuel groups are nuclear units, renewable units (including hydro run of river, solar and wind units (including renewable solar and wind hybrids), storage units (including battery and pumped storage hydro units), thermal units (including combined cycle, CT natural gas and oil, RICE natural gas and oil and steam coal, natural gas and oil) and other units (all other fuels). The 312 projects submitted to TC1 were made up of 233 renewable projects (74.7 percent), 77 storage projects (24.7 percent) and two thermal projects (0.6 percent).

Table 12-59 Transition cycle 1 number of projects by fuel group: March 31, 2026

	Fuel Group										
Year Entered	Nuclear	Percent Nuclear	Renewable	Percent Renewable	Storage	Percent Storage	Thermal	Percent Thermal	Other	Percent Other	Total
2018	0	0.0%	4	80.0%	0	0.0%	1	20.0%	0	0.00%	5
2019	0	0.0%	57	78.1%	15	20.5%	1	1.4%	0	0.00%	73
2020	0	0.0%	172	73.5%	62	26.5%	0	0.0%	0	0.00%	234
Total	0	0.0%	233	74.7%	77	24.7%	2	0.6%	0	0.00%	312

As of March 31, 2026, there were 83 projects in TC1 in the status of active or under construction. Those 83 projects consisted of 66 renewable projects (79.5 percent of all projects and 86.0 percent of the nameplate MW), 16 storage projects (19.3 percent of all projects and 10.0 percent of the nameplate MW) and one thermal project (1.2 percent of all projects and 4.0 percent of the nameplate MW) (Table 12-60).

Table 12-60 Transition cycle 1 details by fuel group: March 31, 2026

Fuel Group	Number of Projects	Percent of Projects	MW	Percent MW
Nuclear	0	0.0%	0.0	0.0%
Renewable	66	79.5%	12,146.0	86.0%
Storage	16	19.3%	1,405.0	10.0%
Thermal	1	1.2%	569.0	4.0%
Other	0	0.0%	0.0	0.0%
Total	83	100.0%	14,120.0	100.0%

Analysis by Unit Type and Project Classification

Table 12-61 shows the status of all new generation projects in TC1 by unit type and project classification as of March 31, 2026. Project classification is defined as either new generation or an uprate in which existing resources are modified to increase the economic maximum generation capability. There were 312 projects, representing 40,650.1 MW, entered into TC1. Of those, 312 projects, 229 projects, representing 26,530.1 MW (65.3 percent of the MW) withdrew prior to completion.

A total of 222 projects have been classified as new generation and 90 projects have been classified as upgrades. Natural gas, wind, solar and renewable hybrid projects (including solar + storage, solar + wind and wind + storage) have accounted for 235 projects (75.3 percent) of all 312 generation projects to enter TC1.

Table 12-61 Transition Cycle 1 status of all generation projects: March 31, 2026

		Number of Projects																					
Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Under Construction	New Generation	1	0	1	0	0	0	0	0	0	0	0	0	3	0	0	0	0	0	0	3	0	8
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	1
Withdrawn	New Generation	25	0	0	0	0	0	0	0	0	0	0	0	95	27	1	0	0	0	0	14	0	162
	Upgrade	36	0	1	0	0	0	0	0	0	0	0	0	23	4	0	0	0	0	0	3	0	67
Active	New Generation	6	0	0	0	0	0	0	0	0	0	0	0	35	5	0	0	0	0	0	6	0	52
	Upgrade	9	0	0	0	0	0	0	0	0	0	0	0	12	0	0	0	0	0	0	1	0	22
Total Projects	New Generation	32	0	1	0	0	0	0	0	0	0	0	0	133	32	1	0	0	0	0	23	0	222
	Upgrade	45	0	1	0	0	0	0	0	0	0	0	0	36	4	0	0	0	0	0	4	0	90

Table 12-62 shows the totals in Table 12-61 by share of classification as new generation or upgrade. Within a unit type the shares of upgrades add to 100 percent and the shares of new generation add to 100 percent. For example, 20.0 percent of all battery projects in TC1 classified as upgrades were active and 80.0 percent of battery projects classified as upgrades were withdrawn from TC1 as of March 31, 2026.

Table 12-62 Transition Cycle 1 status of all generation projects as a percent of total projects by classification: March 31, 2026

		Percent of Projects																					
Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	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%
	Upgrade	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%
Under Construction	New Generation	3.1%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	13.0%	0.0%	3.6%
	Upgrade	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.1%
Withdrawn	New Generation	78.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	71.4%	84.4%	100.0%	0.0%	0.0%	0.0%	0.0%	60.9%	0.0%	73.0%
	Upgrade	80.0%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	63.9%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	75.0%	0.0%	74.4%
Active	New Generation	18.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	26.3%	15.6%	0.0%	0.0%	0.0%	0.0%	0.0%	26.1%	0.0%	23.4%
	Upgrade	20.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	33.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	25.0%	0.0%	24.4%

Table 12-63 shows the total MW of projects in TC1 by unit type and project classification. For example, the 25 new generation battery projects that have been withdrawn from TC1 as of March 31, 2026, (as shown in Table 12-61) constitute 3,629.7 MW. The 95 new generation solar projects that have been withdrawn in the same time period constitute 11,236.8 MW.

Table 12-63 Transition cycle 1 status of all generation (MW) projects: March 31, 2026

		Project MW																					
Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	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
	Upgrade	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
Under Construction	New Generation	75.0	0.0	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	212.0	0.0	0.0	0.0	0.0	0.0	0.0	2,489.0	0.0	3,345.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12.0
Withdrawn	New Generation	3,629.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11,236.8	2,994.8	199.0	0.0	0.0	0.0	0.0	4,360.2	0.0	22,420.4
	Upgrade	1,247.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,133.0	262.4	0.0	0.0	0.0	0.0	0.0	466.6	0.0	4,109.7
Active	New Generation	920.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6,131.1	851.0	0.0	0.0	0.0	0.0	0.0	1,095.9	0.0	8,997.9
	Upgrade	410.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,205.1	0.0	0.0	0.0	0.0	0.0	0.0	150.0	0.0	1,765.1
Total Projects	New Generation	4,624.7	0.0	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	17,579.9	3,845.8	199.0	0.0	0.0	0.0	0.0	7,945.1	0.0	34,763.4
	Upgrade	1,657.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,350.1	262.4	0.0	0.0	0.0	0.0	0.0	616.6	0.0	5,886.8

Table 12-64 shows the MW totals in Table 12-63 share by classification as new generation or upgrade. Within a unit type the shares of upgrades add to 100 percent and the shares of new generation add to 100 percent. For example, 24.7 percent of all battery project MW in TC1 classified as upgrades were active and 75.3 percent of battery project MW classified as upgrades were withdrawn from TC1 as of March 31, 2026.

Table 12-64 Transition cycle 1 status of all generation projects as percent of total MW in project classification: March 31, 2026

		Percent of Total Projects by Classification																					
Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	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%
	Upgrade	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0t%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Under Construction	New Generation	1.6%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	31.3%	0.0%	9.6%
	Upgrade	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%
Withdrawn	New Generation	78.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	63.9%	77.9%	100.0%	0.0%	0.0%	0.0%	0.0%	54.9%	0.0%	64.5%
	Upgrade	75.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	63.7%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	75.7%	0.0%	69.8%
Active	New Generation	19.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	34.9%	22.1%	0.0%	0.0%	0.0%	0.0%	0.0%	13.8%	0.0%	25.9%
	Upgrade	24.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	36.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	24.3%	0.0%	30.0%

Transition Cycle 2 (TC2) and Reliability Resource Initiative (RRI)

On December 13, 2024, PJM submitted modifications to its Open Access Transmission Tariff to add provisions, through a one-time reliability based expansion of the projects in TC2.[88] The MMU supports the stated goals of the December 13th Filing, and supported approval of the December 13th Filing, but also identified significant flaws that compromise the ability of the proposal to achieve its stated goals.[89] PJM's RRI scoring criteria placed undue emphasis on ELCC values rather than on dispatchability. PJM stated that the goal is to be fuel and technology neutral. That is not the appropriate objective when there are defined differences in reliability and dispatchability across resource types, by fuel and technology. The goal of the December 13th Filing should have been to select

88 See *PJM Interconnection L.LC.* Docket No. ER25-712 (December 13, 2024).
89 See IMM Comments. *PJM Interconnection L.LC.* Docket No. ER25-712

the most reliable fuel and technology combinations. PJM also focused on an arbitrary number of projects (50) that could qualify as RRI projects rather than on a target level of MW needed for reliability. PJM should have identified the number of MW, with the required reliability characteristics, that it believes are needed to address PJM's identified reliability shortfall and use the RRI process to obtain those MW. PJM's RRI scoring criteria should have been a series of thresholds that must be met in sequence rather than a single formula that considers all elements simultaneously and assumes that the criteria are comparable through relative weights. The first threshold should have been that the resource is in the right location to address the identified locational reliability issue. The second threshold should have been that the operational characteristics of the resource fully address the identified reliability issue including technology and fuel source(s). The third threshold should have been commercial viability within a defined time period with detailed tracking and strong financial incentives. No RRI resource should have been approved unless it met all three thresholds.

In addition to the one time RRI process, the MMU recommends that PJM establish an ongoing 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.[90] While it is important to respect the existing, improved PJM queue process, it is also 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 becoming actual in service capacity resources suggests strongly that such incentives have not been provided by the queue process.

90 The MMU has consistently supported a stronger role for PJM in addressing immediate reliability needs. As part of the CIR Transfer Efficiency initiative, the MMU proposed to allow PJM to initiate an expedited fast track process to address PJM identified reliability issues. The proposed expedited process would have allowed PJM to open a limited scope expedited reliability process to select projects that address the reliability issues. See "CIR Transfer Efficiency IMM Package," MMU presentation to the PJM Planning Committee (October 8, 2024), <*https://www.monitoringanalytics.com/reports/Presentations/2024/IMM_PC_CIR_Transfer_Efficiency_IMM_Package_20241008_v2.pdf*>.

On February 11, 2025, the Commission approved the RRI tariff modifications.[91] The proposed RRI Tariff revisions created a second TC2 application window that enabled RRI projects to join TC2 and be studied for interconnection during the transition period.

PJM included a range of important enforceable provisions that help ensure that the selected RRI resources will actually go online as promised. These provisions include a must offer obligation which is essential to the efficacy of the entire filing as capacity resources that do not offer do not help solve the identified problem. The MMU supports these provisions.

PJM received 97 applications (28.6 GW) of RRI projects during the RRI application window. Of these projects, 48 involve uprates, in which existing resources are modified to increase the economic maximum generation capability, and 49 propose building new generation. The RRI application window did not limit the number and type of projects (or any restriction on fuel type of projects) that may apply to enter the RRI process. However, PJM restricted the number of RRI projects to be added to TC2 by scoring all the RRI applications using weighted criteria to determine the 50 projects that best satisfy the need for reliable capacity that can be available relatively quickly. The submitted RRI projects were reviewed to determine which projects will be added to TC2.

PJM reviewed the submitted RRI projects using the Commission approved scoring criteria, and approved 51 projects (11,577.4 MW).[92] Table 12-65 shows the status of the 51 approved RRI projects by unit type. On March 31, 2026, all approved RRI projects were either in the status of active or were withdrawn from the cycle. Of the 11,577.4 MW of approved RRI projects, 7,932.4 MW (68.5 percent) were active and 3,645.0 MW (31.5 percent) were withdrawn. Of the 7,932.4 MW in the status of active, 4,843.6 MW (61.1 percent) were combined cycle projects, and 1,575.0 MW (19.9 percent) were battery projects.

91 190 FERC ¶ 61,084 (February 11, 2025).

92 The RRI proposal was to select the top 50 projects using the approved scoring criteria. The implemented scoring criteria resulted in a tie for the 50th project. This resulted in PJM selecting 51 projects as part of the RRI process.

Table 12-65 RRI project status (MW) by unit type: March 31, 2026

	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
Active	1,575.0	4,843.6	11.0	0.0	0.0	0.0	0.0	0.0	1,502.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7,932.4
Withdrawn	700.0	2,945.0	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	3,645.0
Total	2,275.0	7,788.6	11.0	0.0	0.0	0.0	0.0	0.0	1,502.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11,577.4

Of the 51 approved RRI projects, 10 (19.6 percent) have been withdrawn as of March 31, 2026. These 10 projects were withdrawn at the request of the developer. Withdrawn RRI projects highlight the flaws in the project selection stage. A better approach would have been to select enough projects, using supported commercial operation date as a gating criterion, to meet a desired MW quantity (accounting for expected withdrawals) to ensure a reliable outcome rather than a set number of projects.

Table 12-66 shows that on March 31, 2026, there were 7,932.4 MW, on an energy basis, of which 7,443.8 MW are on a capacity basis that requested CIRs, of RRI projects in the status of active or under construction. Table 12-66 also shows the total capacity MW adjusted for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.

Of the 7,443.8 MW, on a capacity basis that requested CIRs, of RRI projects in the status of active or under construction, 5,737.8 MW (77.1 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.

Of the 4,524.9 MW, on a capacity basis that requested CIRs, of RRI combined cycle projects in the status of active or under construction, 3,529.4 MW (78.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.

Of the 1,575.0 MW, on a capacity basis that requested CIRs, of RRI battery projects in the status of active or under construction, 929.3 MW (59.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.

Table 12-66 RRI totals for projects (active and under construction) by unit type adjusted for ELCC derates (MW): March 31, 2026

	Energy (MW)	Capacity (MW)	
Unit Type	Total	Total	ELCC Adjusted
Battery	1,575.0	1,575.0	929.3
CC	4,843.6	4,524.9	3,529.4
CT - Natural Gas	11.0	38.0	25.5
CT - Oil	0.0	0.0	0.0
CT - Other	0.0	0.0	0.0
Fuel Cell	0.0	0.0	0.0
Hydro - Pumped Storage	0.0	0.0	0.0
Hydro - Run of River	0.0	0.0	0.0
Nuclear	1,502.8	1,305.9	1,253.7
RICE - Natural Gas	0.0	0.0	0.0
RICE - Oil	0.0	0.0	0.0
RICE - Other	0.0	0.0	0.0
Solar	0.0	0.0	0.0
Solar + Storage	0.0	0.0	0.0
Solar + Wind	0.0	0.0	0.0
Steam - Coal	0.0	0.0	0.0
Steam - Natural Gas	0.0	0.0	0.0
Steam - Oil	0.0	0.0	0.0
Steam - Other	0.0	0.0	0.0
Wind	0.0	0.0	0.0
Wind + Storage	0.0	0.0	0.0
Total	7,932.4	7,443.8	5,737.8

The application phase for TC2 opened on June 20, 2024, coincident with the close of phase I of transition cycle 1. The application phase required all active projects in queues AG2 and AH1 to reapply under the new rules. The application phase of TC2 was open for 180 days, and closed on December 17, 2024.

There were 1,347 projects (103,151.7 MW) eligible to resubmit for evaluation in TC2. Of those 1,347 eligible projects, 550 projects (49,168.3 MW) resubmitted and are now being evaluated in TC2. Of the 1,347 eligible projects, 797 projects (53,155.5 MW) did not resubmit, and were withdrawn from the queue.

The TC2 application review stage began at the close of the application phase. PJM reviewed the submissions for required data and deposits and built the models required for the TC2 system impact studies. The TC2 application review stage completed on July 6, 2025.

On October 31, 2025, PJM completed the phase I system impact study for transition cycle 2 (TC2). Developers had 30 days (until December 2, 2025) to decide whether to proceed with their new service requests into the next study phase of TC2 or to withdraw their projects. Continuing with phase II required developers to meet the decision point I requirements (including additional readiness deposits and proof of site control).[93]

93 See "PJM Manual 14H: New Service Requests Cycle Process," Rev. 03 (September 25, 2025) for a complete list of all readiness requirements.

On December 3, 2025, PJM began the phase II system impact study process for TC2. The phase II system impact study process is scheduled for 181 days and is set to close on June 1, 2026.

Planned Generation Additions

TC2 is comprised of 647 proposed generation projects. TC2 includes 550 projects submitted during the TC2 window, and 97 projects submitted through the RRI window. Those projects make up 77,760.6 MW. On March 31, 2026, all projects in TC2 were either in the status of active, under construction or were withdrawn from the cycle. Table 12-67 shows each status by unit type. Of the 77,760.6 MW in TC2, 29,882.6 MW (38.3 percent) were active or under construction (29,742.6 MW (38.2 percent) were active and 80 MW (0.1 percent) were under construction) and 47,938.0 MW (61.6 percent) were withdrawn. Of the 29,742.6 MW in the status of active, 11,646.1 MW (39.2 percent) are solar projects, 468.4 MW (1.6 percent) are wind projects, and 6,335.8 MW (21.3 percent) are battery projects.

Table 12-67 Transition cycle 2 and RRI project status (MW) by unit type: March 31, 2026

	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
Active	6,335.8	6,943.6	763.0	0.0	30.1	5.0	0.0	0.0	1,502.8	0.0	0.0	0.0	11,646.1	2,047.8	0.0	0.0	0.0	0.0	0.0	468.4	0.0	29,742.6
Under Construction	80.0	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	80.0
Withdrawn	13,515.9	13,742.6	0.0	0.0	0.0	0.0	0.0	19.3	0.0	0.0	0.0	0.0	13,687.6	3,465.0	10.0	0.0	0.0	0.0	3.2	3,494.4	0.0	47,938.0
Total	19,931.7	20,686.2	763.0	0.0	30.1	5.0	0.0	19.3	1,502.8	0.0	0.0	0.0	25,333.8	5,512.8	10.0	0.0	0.0	0.0	3.2	3,962.8	0.0	77,760.6

Table 12-68 shows the projects in TC2 with a status of active or under construction, by unit type, and control zone. As of March 31, 2026, 29,822.6 MW were in TC2 for construction through 2031. Table 12-68 also shows the planned retirements for each zone.

Table 12-68 Transition cycle 2 and RRI totals for projects (active and under construction) by LDA, control zone and unit type (MW): March 31, 2026

LDA	Zone	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total Queue Capacity	Planned Retirements
EMAAC	ACEC	300.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	84.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	384.0	175.1
	DPL	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	102.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	122.2	16.4
	JCPLC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	117.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	117.9	65.0
	PECO	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	760.0
	PSEG	0.0	293.2	0.0	0.0	0.0	0.0	0.0	0.0	256.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	550.0	2.0
	REC	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
	EMAAC Total	320.0	293.2	0.0	0.0	0.0	0.0	0.0	0.0	256.8	0.0	0.0	0.0	304.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,174.1	1,018.5
SWMAAC	BGE	635.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	55.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	690.0	1,975.0
	PEPCO	0.0	53.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	110.0	670.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	833.7	0.0
	SWMAAC Total	635.0	53.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	165.0	670.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,523.7	1,975.0
WMAAC	MEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	859.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	859.0	0.0
	PE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	354.0	25.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	379.0	10.4
	PPL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	48.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	48.0	0.0
	WMAAC Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	859.0	0.0	0.0	0.0	402.0	25.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,286.0	10.4
Non-MAAC	AEP	1,703.0	72.0	752.0	0.0	10.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,298.2	565.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6,400.8	2,620.0
	AMPT	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
	APS	390.0	2,370.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	614.9	46.5	0.0	0.0	0.0	0.0	0.0	468.4	0.0	3,890.1	31.5
	ATSI	150.0	1,796.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	170.0	110.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,226.7	0.0
	COMED	1,187.0	0.0	11.0	0.0	0.0	5.0	0.0	0.0	387.0	0.0	0.0	0.0	2,135.0	359.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4,084.8	2,671.9
	DAY	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
	DUKE	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
	DLCO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.7	0.0
	DOM	2,030.8	1,572.0	0.0	0.0	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,610.7	207.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7,441.1	2.0
	EKPC	0.0	786.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	543.0	63.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,392.3	116.0
	OVEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	398.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	398.5	0.0
	RMU	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-MAAC Total	5,460.8	6,597.0	763.0	0.0	30.1	5.0	0.0	0.0	387.0	0.0	0.0	0.0	10,775.0	1,352.6	0.0	0.0	0.0	0.0	0.0	468.4	0.0	25,838.8	5,441.4
Total		6,415.8	6,943.6	763.0	0.0	30.1	5.0	0.0	0.0	1,502.8	0.0	0.0	0.0	11,646.1	2,047.8	0.0	0.0	0.0	0.0	0.0	468.4	0.0	29,822.6	8,445.3

Table 12-69 shows that on March 31, 2026, there were 29,822.6 MW, on an energy basis, of which 21,719.2 MW are on a capacity basis that requested CIRs, in TC2 in the status of active or under construction. Table 12-69 also shows the total capacity MW adjusted for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.

Of the 21,719.2 MW, on a capacity basis that requested CIRs in TC2 in the status of active or under construction, 10,753.4 MW (49.5 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.

Of the 7,337.9 MW, on a capacity basis that requested CIRs, of thermal projects (including combined cycle and CT natural gas projects) requested in TC2 in the status of active or under construction, 5,642.4 MW (76.9 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.

Of the 6,366.4 MW, on a capacity basis that requested CIRs, of solar projects requested in TC2 in the status of active or under construction, 636.6 MW (10.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.

Of the 5,122.3 MW, on a capacity basis that requested CIRs, of battery projects requested in TC2 in the status of active or under construction, 3,022.2 MW (59.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.

Of the 7,919.1 MW, on a capacity basis that requested CIRs, of renewable projects requested in TC2 in the status of active or under construction, 811.2 MW (10.2 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.

Table 12-69 Transition cycle 2 and RRI totals for projects (active and under construction) by unit type adjusted for ELCC derates (MW): March 31, 2026

	Energy (MW)		Capacity (MW)
Unit Type	Total	Total	ELCC Adjusted
Battery	6,415.8	5,122.3	3,022.2
CC	6,943.6	6,599.9	5,147.9
CT - Natural Gas	763.0	738.0	494.5
CT - Oil	0.0	0.0	0.0
CT - Other	30.1	29.1	19.5
Fuel Cell	5.0	5.0	4.6
Hydro - Pumped Storage	0.0	0.0	0.0
Hydro - Run of River	0.0	0.0	0.0
Nuclear	1,502.8	1,305.9	1,253.7
RICE - Natural Gas	0.0	0.0	0.0
RICE - Oil	0.0	0.0	0.0
RICE - Other	0.0	0.0	0.0
Solar	11,646.1	6,366.4	636.6
Solar + Storage	2,047.8	1,472.5	147.2
Solar + Wind	0.0	0.0	0.0
Steam - Coal	0.0	0.0	0.0
Steam - Natural Gas	0.0	0.0	0.0
Steam - Oil	0.0	0.0	0.0
Steam - Other	0.0	0.0	0.0
Wind	468.4	80.2	27.3
Wind + Storage	0.0	0.0	0.0
Total	29,822.6	21,719.2	10,753.4

Withdrawn Projects

Table 12-70 shows the status of all TC2 projects as they have progressed through the cycle process. Of the 647 projects included in TC2, 47 projects (7.1 percent of all projects and 21.9 percent of the total MW) were withdrawn as part of the RRI evaluation, 51 projects (7.9 percent of all projects and 6.7 percent of the total MW) were withdrawn prior to the beginning of phase I, and 272 projects (42.0 percent of all projects and 33.1 percent of the total MW) were withdrawn during phase I or decision point I. On March 31, 2026, 278 projects (43.0 percent of all projects and 38.4 percent of the total MW) remain active in TC2.

Table 12-70 Transition cycle 2 and RRI status: March 31, 2026

	Number of Projects	Percent of Projects	MW Energy	Percent of MW Energy
Transition cycle 2 approved projects	647	100.0%	77,760.6	100.0%
RRI projects not selected	46	7.1%	17,014.8	21.9%
Withdrawn prior to start of phase I	51	7.9%	5,201.1	6.7%
Withdrawn during phase I or decision point I	272	42.0%	25,722.0	33.1%
Withdrawn during phase II or decision point II	0	0.0%	0.0	0.0%
Active as of March 31, 2026	270	41.7%	29,742.6	38.2%
In final agreement stage as of March 31, 2026	4	0.6%	0.0	0.0%
Under Construction	4	0.6%	80.0	0.1%
In Service	0	0.0%	0.0	0.0%

Table 12-71 shows 77,760.6 MW have entered TC2. Table 12-71 presents totals by fuel type and projected in service date as of March 31, 2026. Of the 77,760.6 MW to enter TC2, 21,449.2 MW (27.6 percent) were thermal units.

Table 12-71 Transition cycle 2 and RRI total (MW Energy) by unit type and projected in service year: March 31, 2026

Year	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
2019	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
2020	207.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	523.9	33.0	0.0	0.0	0.0	0.0	0.0	250.0	0.0	1,013.9
2021	7,161.9	0.0	0.0	0.0	0.0	0.0	0.0	19.3	0.0	0.0	0.0	0.0	12,979.7	2,849.0	10.0	0.0	0.0	0.0	0.0	3,244.4	0.0	26,264.3
2022	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
2023	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
2024	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
2025	6,147.0	13,800.6	52.0	0.0	0.0	5.0	0.0	0.0	0.0	0.0	0.0	0.0	202.0	583.0	0.0	0.0	0.0	0.0	3.2	0.0	0.0	20,792.8
2026	0.0	44.0	0.0	0.0	10.1	0.0	0.0	0.0	88.0	0.0	0.0	0.0	140.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	282.2
2027	100.0	167.6	0.0	0.0	20.0	0.0	0.0	0.0	1,245.8	0.0	0.0	0.0	540.7	733.5	0.0	0.0	0.0	0.0	0.0	147.0	0.0	2,954.5
2028	2,125.0	0.0	11.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,797.5	1,265.3	0.0	0.0	0.0	0.0	0.0	321.4	0.0	9,520.2
2029	3,705.0	127.2	700.0	0.0	0.0	0.0	0.0	0.0	169.0	0.0	0.0	0.0	3,712.5	49.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8,462.7
2030	425.0	2,894.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,237.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4,557.2
2031	60.8	3,652.0	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	3,712.8
2032	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	200.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	200.0
Total	19,931.7	20,686.2	763.0	0.0	30.1	5.0	0.0	19.3	1,502.8	0.0	0.0	0.0	25,333.8	5,512.8	10.0	0.0	0.0	0.0	3.2	3,962.8	0.0	77,760.6

Table 12-72 shows there were 29,822.6 MW in TC2 in the status of active or under construction as of March 31, 2026. Table 12-72 presents totals by fuel type and projected in service date. Of the 29,822.6 MW, 7,706.6 MW (25.8 percent) are thermal units.

Table 12-72 Transition cycle 2 and RRI total (MW Energy) by unit type and projected in service year (active and under construction): March 31, 2026

Year	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
2019	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
2020	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
2021	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
2022	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
2023	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
2024	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
2025	0.0	58.0	52.0	0.0	0.0	5.0	0.0	0.0	0.0	0.0	0.0	0.0	18.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	133.0
2026	0.0	44.0	0.0	0.0	10.1	0.0	0.0	0.0	88.0	0.0	0.0	0.0	140.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	282.2
2027	100.0	167.6	0.0	0.0	20.0	0.0	0.0	0.0	1,245.8	0.0	0.0	0.0	540.7	733.5	0.0	0.0	0.0	0.0	0.0	147.0	0.0	2,954.5
2028	2,125.0	0.0	11.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,797.5	1,265.3	0.0	0.0	0.0	0.0	0.0	321.4	0.0	9,520.2
2029	3,705.0	127.2	700.0	0.0	0.0	0.0	0.0	0.0	169.0	0.0	0.0	0.0	3,712.5	49.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8,462.7
2030	425.0	2,894.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,237.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4,557.2
2031	60.8	3,652.0	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	3,712.8
2032	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	200.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	200.0
Total	6,415.8	6,943.6	763.0	0.0	30.1	5.0	0.0	0.0	1,502.8	0.0	0.0	0.0	11,646.1	2,047.8	0.0	0.0	0.0	0.0	0.0	468.4	0.0	29,822.6

Table 12-73 shows there were 47,938.0 MW withdrawn from TC2 as of March 31, 2026. Table 12-73 presents totals by fuel type and projected in service date. Of the 47,938.0 MW withdrawn from TC2, 13,742.6 MW (28.7 percent) were thermal units.

Table 12-73 Transition cycle 2 and RRI total (MW Energy) by unit type and projected in service year (withdrawn): March 31, 2026

Year	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
2019	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
2020	207.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	523.9	33.0	0.0	0.0	0.0	0.0	0.0	250.0	0.0	1,013.9
2021	7,161.9	0.0	0.0	0.0	0.0	0.0	0.0	19.3	0.0	0.0	0.0	0.0	12,979.7	2,849.0	10.0	0.0	0.0	0.0	0.0	3,244.4	0.0	26,264.3
2022	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
2023	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
2024	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
2025	6,147.0	13,742.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	184.0	583.0	0.0	0.0	0.0	0.0	3.2	0.0	0.0	20,659.8
2026	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
2027	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
2028	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
2029	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
2030	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
2031	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
Total	13,515.9	13,742.6	0.0	0.0	0.0	0.0	0.0	19.3	0.0	0.0	0.0	0.0	13,687.6	3,465.0	10.0	0.0	0.0	0.0	3.2	3,494.4	0.0	47,938.0

Analysis by Fuel Group

Table 12-74 shows the number of projects that entered TC2 by year and by fuel group. The fuel groups are nuclear units, renewable units (including hydro run of river, solar and wind units (including renewable solar and wind hybrids), storage units (including battery and pumped storage hydro units), thermal units (including combined cycle, CT natural gas and oil, RICE natural gas and oil and steam coal, natural gas and oil) and other units (all other fuels). The 647 projects submitted to TC2 were made up of 391 renewable projects (60.4 percent), 188 storage projects (29.1 percent), 58 thermal projects (9.0 percent), five nuclear projects (0.8 percent) and five other fuel projects (0.8 percent).

Table 12-74 Transition cycle 2 and RRI number of projects by fuel group: March 31, 2026

	Fuel Group										
Year Entered	Nuclear	Percent Nuclear	Renewable	Percent Renewable	Storage	Percent Storage	Thermal	Percent Thermal	Other	Percent Other	Total
2018	0	0.0%	1	100.0%	0	0.0%	0	0.0%	0	0.0%	1
2019	0	0.0%	2	100.0%	0	0.0%	0	0.0%	0	0.0%	2
2020	0	0.0%	18	72.0%	6	24.0%	0	0.0%	1	4.0%	25
2021	0	0.0%	365	69.9%	150	28.7%	4	0.8%	3	0.6%	522
2022	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0
2023	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0
2024	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0
2025	5	5.2%	5	5.2%	32	33.0%	54	55.7%	1	1.0%	97
Total	5	0.8%	391	60.4%	188	29.1%	58	9.0%	5	0.8%	647

As of March 31, 2026, there were 278 projects in TC2 in the status of active or under construction. Those 278 projects consisted of 172 renewable projects (61.9 percent of all projects and 47.5 percent of the nameplate MW), 62 storage projects (22.3 percent of all projects and 21.5 percent of the nameplate MW), 36 thermal projects (12.9 percent of all projects and 25.8 percent of the nameplate MW), five nuclear projects (1.8 percent of all projects and 5.0 percent of the nameplate MW) and three other fuel type projects (1.1 percent of all projects and 0.01 percent of the nameplate MW) (Table 12-75).

Table 12-75 Transition cycle 2 and RRI details by fuel group: March 31, 2026

Fuel Group	Number of Projects	Percent of Projects	MW	Percent MW
Nuclear	5	1.8%	1,502.8	5.0%
Renewable	172	61.9%	14,162.3	47.5%
Storage	62	22.3%	6,415.8	21.5%
Thermal	36	12.9%	7,706.6	25.8%
Other	3	1.1%	35.1	0.1%
Total	278	100.0%	29,822.6	100.0%

Analysis by Unit Type and Project Classification

Table 12-76 shows the status of all new generation projects in TC2 by unit type and project classification as of March 31, 2026. Project classification is defined as either new generation or an uprate in which existing resources are modified to increase the economic maximum generation capability. There were 647 projects, representing 77,760.6 MW, entered into TC2. Of those, 647 projects, 369 projects, representing 47,938.0 MW (61.6 percent of the MW) withdrew prior to completion.

A total of 424 projects have been classified as new generation and 223 projects have been classified as upgrades. Natural gas, wind, solar and renewable hybrid projects (including solar + storage, solar + wind and wind + storage) have accounted for 446 projects (68.9 percent) of all 647 generation projects to enter TC2.

Table 12-76 Transition Cycle 2 and RRI status of all generation projects: March 31, 2026

		Number of Projects																					
Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Under Construction	New Generation	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Withdrawn	New Generation	67	14	0	0	0	0	0	2	0	0	0	0	130	32	1	0	0	0	1	7	0	254
	Upgrade	59	8	0	0	1	0	0	0	0	0	0	0	41	5	0	0	0	0	0	1	0	115
Active	New Generation	33	5	1	0	1	0	0	0	1	0	0	0	104	18	0	0	0	0	0	3	0	166
	Upgrade	25	18	11	0	1	1	0	0	4	0	0	0	44	2	0	1	0	0	0	1	0	108
Total Projects	New Generation	104	19	1	0	1	0	0	2	1	0	0	0	234	50	1	0	0	0	1	10	0	424
	Upgrade	84	26	11	0	2	1	0	0	4	0	0	0	85	7	0	1	0	0	0	2	0	223

Table 12-77 shows the totals in Table 12-76 by share of classification as new generation or upgrade. Within a unit type the shares of upgrades add to 100 percent and the shares of new generation add to 100 percent. For example, 29.8 percent of all battery projects in TC2 classified as upgrades were active and 70.2 percent of battery projects classified as upgrades were withdrawn from TC2 as of March 31, 2026.

Table 12-77 Transition Cycle 2 and RRI status of all generation projects as a percent of total projects by classification: March 31, 2026

		Percent of Projects																					
Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	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%
	Upgrade	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%
Under Construction	New Generation	3.8%	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%	0.9%
	Upgrade	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%
Withdrawn	New Generation	64.4%	73.7%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	55.6%	64.0%	100.0%	0.0%	0.0%	0.0%	100.0%	70.0%	0.0%	59.9%
	Upgrade	70.2%	30.8%	0.0%	0.0%	50.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	48.2%	71.4%	0.0%	0.0%	0.0%	0.0%	0.0%	50.0%	0.0%	51.6%
Active	New Generation	31.7%	26.3%	100.0%	0.0%	100.0%	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	44.4%	36.0%	0.0%	0.0%	0.0%	0.0%	0.0%	30.0%	0.0%	39.2%
	Upgrade	29.8%	69.2%	100.0%	0.0%	50.0%	100.0%	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	51.8%	28.6%	0.0%	100.0%	0.0%	0.0%	0.0%	50.0%	0.0%	48.4%

Table 12-78 shows the total MW of projects in TC2 by unit type and project classification. For example, the 67 new generation battery projects that have been withdrawn from TC2 as of March 31, 2026, (as shown in Table 12-76) constitute 10,075.1 MW. The 130 new generation solar projects that have been withdrawn in the same time period constitute 10,806.9 MW.

Table 12-78 Transition cycle 2 and RRI status of all generation (MW) projects: March 31, 2026

		Project MW																						
Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	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
	Upgrade	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
Under Construction	New Generation	80.0	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	80.0
	Upgrade	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
Withdrawn	New Generation	10,075.1	13,492.2	0.0	0.0	0.0	0.0	0.0	19.3	0.0	0.0	0.0	0.0	10,806.9	3,097.6	10.0	0.0	0.0	0.0	3.2	3,426.4	0.0	40,930.7
	Upgrade	3,440.8	250.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,880.7	367.4	0.0	0.0	0.0	0.0	0.0	68.0	0.0	7,007.3
Active	New Generation	5,199.4	5,738.0	700.0	0.0	10.1	0.0	0.0	0.0	859.0	0.0	0.0	0.0	9,556.1	1,967.8	0.0	0.0	0.0	0.0	0.0	468.4	0.0	24,498.8
	Upgrade	1,136.4	1,205.6	63.0	0.0	20.0	5.0	0.0	0.0	643.8	0.0	0.0	0.0	2,090.0	80.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,243.8
Total Projects	New Generation	15,354.5	19,230.2	700.0	0.0	10.1	0.0	0.0	19.3	859.0	0.0	0.0	0.0	20,363.1	5,065.4	10.0	0.0	0.0	0.0	3.2	3,894.8	0.0	65,509.4
	Upgrade	4,577.2	1,456.0	63.0	0.0	20.0	5.0	0.0	0.0	643.8	0.0	0.0	0.0	4,970.7	447.4	0.0	0.0	0.0	0.0	0.0	68.0	0.0	12,251.1

Table 12-79 shows the MW totals in Table 12-78 by share by classification as new generation or upgrade. Within a unit type the shares of upgrades add to 100 percent and the shares of new generation add to 100 percent. For example, 24.8 percent of all battery project MW in TC2 classified as upgrades were active and 75.2 percent of battery project MW classified as upgrades were withdrawn from TC2 as of March 31, 2026.

Table 12-79 Transition cycle 2 and RRI status of all generation projects as percent of total MW in project classification: March 31, 2026

		Percent of Total Projects by Classification																					
Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	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%
	Upgrade	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%
Under Construction	New Generation	0.5%	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%	0.1%
	Upgrade	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%
Withdrawn	New Generation	65.6%	70.2%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	53.1%	61.2%	100.0%	0.0%	0.0%	0.0%	100.0%	88.0%	0.0%	62.5%
	Upgrade	75.2%	17.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	58.0%	82.1%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	57.2%
Active	New Generation	33.9%	29.8%	100.0%	0.0%	100.0%	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	46.9%	38.8%	0.0%	0.0%	0.0%	0.0%	0.0%	12.0%	0.0%	37.4%
	Upgrade	24.8%	82.8%	100.0%	0.0%	100.0%	100.0%	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	42.0%	17.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	42.8%

Cycle Process Totals[94]

On March 31, 2026, there were 959 proposed generation projects in the new services cycle process queues. Those projects make up 118,410.7 MW. On March 31, 2026, all projects in the cycle process queues were either in the status of active, under construction or were withdrawn. Table 12-80 shows each status by unit type. Of the 118,410.7 MW in the cycle process queues, 43,942.6 MW (37.1 percent) were active or under construction (40,505.6 MW (34.2 percent) were active and 3,437.0 MW (2.9 percent) were under construction) and 74,468.0 MW (62.9 percent) were withdrawn. Of the 40,505.6 MW in the status of active, 18,982.3 MW (46.9 percent) were solar projects, 1,714.3 MW (4.2 percent) were wind projects, and 7,665.8 MW (18.9 percent) were battery projects.

94 As of March 31, 2026, the cycle process totals include those projects included in TC1 and TC2.

Table 12-80 All cycles (TC1, TC2 and RRI) project status (MW) by unit type: March 31, 2026

	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
Active	7,665.8	6,943.6	763.0	0.0	30.1	5.0	0.0	0.0	1,502.8	0.0	0.0	0.0	18,982.3	2,898.8	0.0	0.0	0.0	0.0	0.0	1,714.3	0.0	40,505.6
Under Construction	155.0	0.0	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	224.0	0.0	0.0	0.0	0.0	0.0	0.0	2,489.0	0.0	3,437.0
Withdrawn	18,393.3	13,742.6	0.0	0.0	0.0	0.0	0.0	19.3	0.0	0.0	0.0	0.0	27,057.4	6,722.2	209.0	0.0	0.0	0.0	3.2	8,321.1	0.0	74,468.0
Total	26,214.1	20,686.2	1,332.0	0.0	30.1	5.0	0.0	19.3	1,502.8	0.0	0.0	0.0	46,263.7	9,620.9	209.0	0.0	0.0	0.0	3.2	12,524.4	0.0	118,410.7

Table 12-81 shows that on March 31, 2026, there were 43,942.6 MW, on an energy basis, of which 28,518.1 MW are on a capacity basis that requested CIRs, in cycle process queues in the status of active or under construction. Table 12-81 also shows the total capacity MW adjusted for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.

Of the 28,518.1 MW, on a capacity basis that requested CIRs in the cycle process queues in the status of active or under construction, 12,495.1 MW (43.8 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.

Of the 7,906.9 MW, on a capacity basis that requested CIRs, of thermal projects (including combined cycle and CT natural gas projects) requested in cycle process queues in the status of active or under construction, 6,023.6 MW (76.2 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.

Of the 10,093.8 MW, on a capacity basis that requested CIRs, of solar projects requested in cycle process queues in the status of active or under construction, 1,09.4 MW (10.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.

Of the 6,144.3 MW, on a capacity basis that requested CIRs, of battery projects requested in cycle process queues in the status of active or under construction, 3,625.1 MW (59.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.

Of the 13,127.0 MW, on a capacity basis that requested CIRs, of renewable projects requested in cycle process queues in the status of active or under construction, 1,568.6 MW (11.9 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2028/2029 Base Residual Auction.

Table 12-81 All cycles (TC1, TC2 and RRI) projects (active and under construction) by unit type adjusted for ELCC derates (MW): March 31, 2026

	Energy (MW)		Capacity (MW)
Unit Type	Total	Total	ELCC Adjusted
Battery	7,820.8	6,144.3	3,625.1
CC	6,943.6	6,599.9	5,147.9
CT - Natural Gas	1,332.0	1,307.0	875.7
CT - Oil	0.0	0.0	0.0
CT - Other	30.1	29.1	19.5
Fuel Cell	5.0	5.0	4.6
Hydro - Pumped Storage	0.0	0.0	0.0
Hydro - Run of River	0.0	0.0	0.0
Nuclear	1,502.8	1,305.9	1,253.7
RICE - Natural Gas	0.0	0.0	0.0
RICE - Oil	0.0	0.0	0.0
RICE - Other	0.0	0.0	0.0
Solar	19,206.3	10,093.8	1,009.4
Solar + Storage	2,898.8	1,966.7	196.7
Solar + Wind	0.0	0.0	0.0
Steam - Coal	0.0	0.0	0.0
Steam - Natural Gas	0.0	0.0	0.0
Steam - Oil	0.0	0.0	0.0
Steam - Other	0.0	0.0	0.0
Wind	4,203.3	1,066.4	362.6
Wind + Storage	0.0	0.0	0.0
Total	43,942.6	28,518.1	12,495.1

Serial and Cycle Process Totals

On July 10, 2023, there were 287,185.2 MW in the status of active, under construction or suspended in the serial queue. As part of the transition to the new cycle process, projects were removed from the queue because developers chose to not resubmit their projects in the TC2 queue, invalid projects were removed and must be resubmitted in Cycle 1, and projects were withdrawn as part of the normal queue process. On March 31, 2026, of the 287,185.2 MW, there were 76,230.9 MW (26.5 percent) in the status of active, in service or under construction, 9,428.1 MW (3.3 percent) went in service, and 201,526.2 MW (70.2 percent) have been withdrawn from the queue.

On March 31, 2026, there were 6,420 proposed generation projects in the combined serial and new services cycle process queues. Those projects make up 727,638.1 MW. On March 31, 2026, projects in the combined serial and cycle process queues were in the status of active, under construction, suspended, in service or were withdrawn. Of the 727,638.1 MW in the combined serial and cycle process queues, 84,163.3 MW (11.6 percent) were active, under construction or suspended (60,431.0 MW (8.3 percent) were active, 16,180.5 MW (2.2 percent) were under construction and 7,551.8 MW (1.0 percent) were suspended), 95,178.1 MW (13.1 percent) were in service and 548,296.7 MW (75.4 percent) were withdrawn.

Of the 84,163.3 MW in the combined serial and cycle process queues in the status of active, under construction or suspended, 13,588.1 MW (16.1 percent) are thermal projects.

Surplus Interconnection Service (SIS)

FERC Order 845 required transmission providers to create a process for interconnection customers to use surplus interconnection service at existing points of interconnection.[95] Surplus interconnection service is defined as "any unneeded portion of interconnection service established in a large generator interconnection agreement (LGIA), such that if surplus interconnection service is utilized, the total amount of interconnection service at the point of interconnection would remain the same."[96] For example, a developer may request SIS to add a solar facility at the location of an existing battery storage facility. In this example, the battery storage facility operates at night only, while the solar facility operates during the day. The net output at the point of interconnection would never exceed the maximum facility output as studied for the existing battery storage facility's generation interconnection agreement.

Surplus interconnection service requests can be made by a project developer or one of its affiliates whose generating facility is already interconnected to the PJM transmission system or has executed (or requested to file unexecuted) an interconnection service agreement (ISA) or generation interconnection agreement (GIA), or by an unaffiliated project developer. The project developer, or one of its affiliates, has priority to use the service. However, if a project developer or affiliate does not submit a request for SIS, an unaffiliated project developer may request service. Under the SIS process, projects that do not trigger transmission system upgrades qualify for expedited review by PJM outside the interconnection queue. In order for a SIS request to be approved, no new network upgrades must be required to accommodate the request.[97]

If surplus interconnection service is requested on a generating facility that is an energy only resource, the generating facility requesting the SIS will also be an energy only resource. If surplus interconnection service is requested on a generating facility that is a capacity resource, the generating facility requesting surplus interconnection service may be an energy resource or a capacity resource, not to exceed the amount of CIRs established in the ISA or GIA. Requests for SIS are not posted publicly by PJM.

Interconnection Costs for New Projects

Any entity that requests interconnection of a new generating facility, including increases to the capacity of an existing generating unit, or that requests interconnection of a merchant transmission facility, must follow the process defined in the PJM tariff to obtain interconnection service.[98] PJM's process is designed to ensure that new generation is added in a reliable and systematic manner. As part of the interconnection planning process, a series of studies

95 See *Reform of Generator Interconnection Procedures and Agreements, Order No. 845*, 163 FERC ¶ 61,043 (2018).
96 Id. At Pg. 373
97 See "PJM Manual 14H: New Service Requests Cycle Process," Rev. 03 (September 25, 2025)
98 See OATT Parts IV & VI.

are performed to determine the feasibility, impact, and cost of interconnecting projects in the queue. Interconnection requests are for energy only resources and for capacity resources.

Interconnecting capacity resources must meet a higher standard than energy only resources. For interconnecting capacity resources, PJM performs deliverability studies that ensure that the energy from the proposed generator can be reliably provided to the PJM region. Deliverability studies identify network upgrades needed to ensure that the transmission system is capable of delivering the aggregate system generating capacity at peak load, including the new resource, with all firm transmission service modeled.[99] The interconnection service agreement identifies the transmission modifications needed to maintain the reliability of the transmission system as a result of a new service request. These identified modifications are known as network upgrades. In general, there are fewer network upgrades associated with energy only resources, as energy only resources are not required to be deliverable to the entire PJM footprint.[100] On March 31, 2026, there were 2,126 active network transmission upgrades. If a project is withdrawn from the queue, the network upgrades associated with that project are no longer required, unless it is required to support another queue project.

While not all projects in the queue require network upgrades, the number of planned network transmission upgrades is strongly correlated with the number of active projects in the queue. The number of planned network upgrades is also strongly correlated with the number of new generation projects requesting interconnection as a capacity resource. After the execution of an interconnection service agreement, queue projects become part of the RTEP study and the costs of any upgrade later necessary to preserve their Capacity Interconnection Rights are included as part of the overall transmission system costs paid by all transmission customers.

The system impact study is a detailed system analysis performed for new service requests that tests deliverability under peak load conditions and light load conditions. The system impact study identifies system constraints caused by the request and the local upgrades and network upgrades required to solve those constraints. The system impact study includes power flow analysis and short circuit analysis. The power flow analysis includes expected output level from the new resource under summer peak and light load system conditions.[101] PJM's recent improvements to the deliverability analyses reflect more accurate information about the expected performance of intermittent resources, by type of resource (solar fixed, solar tracking, onshore wind and offshore wind), by season (summer, winter and light load) and by region (PJM West, Mid-Atlantic and Dominion), under each of these system conditions. Those modifications are necessary to accurately reflect the expected output of intermittent resources under various seasons and system conditions as the penetration and role of intermittents in PJM increases.[102] For example, the expected output of onshore wind varies from its maximum facility output to zero, depending on weather conditions, and the expected output levels are used for each system load condition.[103]

Capacity resources receive Capacity Interconnection Rights (CIRs) based on the deliverable MW which result from a combination of upgrades paid for by each project and existing system capability. Intermittent resources also require CIRs. The level of CIRs required for intermittent resources has been significantly understated because the required CIRs have been based on the derated capacity value of intermittents rather than the maximum energy injections required to achieve the derated value.

After a lengthy stakeholder process, on April 7, 2023, FERC approved updates to PJM's ELCC method that cap the level of an intermittent generator's output used to calculate the generator's reliability contribution (ELCC derated MW) at the generator's CIR level.[104] Rules prior to the FERC order allowed generation at a level greater than the CIR value, and that was therefore not deliverable, to be inappropriately included in the ELCC calculations. For example, if a 100 MW solar resource has CIRs of 60 MW, generation in excess of 60 MW will not be included in the ELCC calculations under the updated rules.

99 See "PJM Manual 14B: PJM Regional Transmission Planning Process," Rev. 58 (December 17, 2025).
100 See "PJM Manual 14G: Generation Interconnection Requests," Rev. 8 (July 26, 2023).

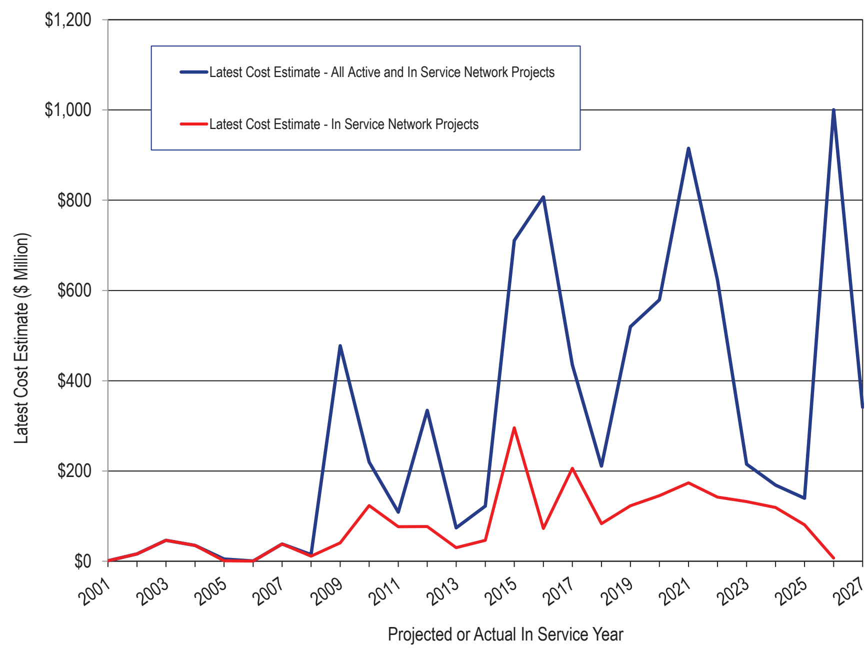
101 Winter peak load is included in the generation deliverability powerflow analysis during the RTEP baseline reliability analysis, but is not currently performed for new interconnection requests. The light load analysis ensures generation deliverability during light load conditions, which is defined as 50 percent of the annual peak demand.
102 See "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 58 (December 17, 2025).
103 See "Generation Deliverability Test Modifications: Light Load, Summer & Winter," presented at January 25, 2023 meeting of the Markets and Reliability Committee <https://www.pjm.com/-/media/committees-groups/committees/mrc/2023/20230125/consent-agenda-c---1-generator-deliverability-test-revisions---presentation.ashx>.
104183 FERC ¶61,009.

Prior to the update, the generation in excess of the CIR level was included, overstating the ELCC ratings and reliability contribution of ELCC resources. The overstatement of intermittent capacity has inefficiently suppressed capacity market clearing prices.[105] [106] In order to retain the prior, incorrectly calculated ELCC values, existing intermittent generating units are required to increase their CIRs by going through an expedited queue process. The ELCC updates established a transitional period during which intermittent generators can be awarded temporary increases in their CIRs based on the availability of transmission system capability.[107] PJM expects a transitional period of four years, beginning with the 2025/2026 Base Residual Auction, to be sufficient time for intermittent resources to reenter the queue and be awarded additional CIRs. New intermittent generators will be required to pay for CIRs consistent with their calculated reliability contribution.

Figure 12-5 shows the latest estimated interconnection costs for new generators (network transmission project cost) by projected and actual in service year for generators that are in service (red line), and for the total of generators in service and still in the queue in active status (blue line). The estimated costs for in service projects (red line) are much lower than the estimated costs that also include all projects in the queue (blue line). The increase in estimated total network upgrade costs for planned projects is a result of the large number of requests in the new services queue and the existing backlog (Figure 12-5). However, as generators withdraw from the queue, the overall network costs decrease. The estimated network upgrade costs for in service projects are much lower. The projected in service dates for network projects are not updated regularly, and therefore, may not be an accurate predictor of when these projects are actually expected to go in service. Figure 12-5 shows a significant level of estimated interconnection costs for resources with projected in service dates as far back as 2008 and a peak for projects with a projected in service date of 2026. Even the costs for projects that are in service are only estimates because PJM does not track final project costs. The final in service costs include only the last estimate provided by PJM before the project went in service. PJM's data collection, management and retention related to transmission spending of all types is inadequate and needs a significant upgrade. The failure to collect data on estimated and final project costs makes it impossible to track transmission project costs for all project types. 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.

105 *See* "Analysis of the 2023/2024 RPM Base Residual Auction," <*http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf*>. (October 28, 2022).
106 *See* "Analysis of the 2022/2023 RPM Base Residual Auction—Revised," <*https://www.monitoringanalytics.com/reports/Reports/2023/IMM_Analysis_of_the_20222023_RPM_BRA_Revised_20230113.pdf*> (January 13, 2023).
107 183 FERC ¶61,009 at 31.

Figure 12-5 Cost estimates of network projects by projected and actual in service year: January 1, 2001 through December 31, 2027



Regional Transmission Expansion Plan (RTEP)[108]

The PJM RTEP process is designed to identify needed transmission system additions and improvements to continue to provide reliable service throughout the RTO. The objective of the RTEP process is to provide PJM with an optimal set of solutions necessary to solve reliability issues, operational performance issues and transmission constraints.

The RTEP process initially considered only factors such as load growth and the generation interconnection requests in its development of the 15 year plan. Currently, the RTEP process includes a broader range of inputs including the effects of public policy, market efficiency, interregional coordination and the effects of aging infrastructure.

RTEP Process

The PJM RTEP process is a 24 month planning process that identifies reliability issues for the next 15 year period. This 24 month planning process includes a process to build power flow models that represent the expected future system topology, studies to identify issues, stakeholder input and PJM Board of Managers approvals. The 24 month planning process is made up of overlapping 18 month planning cycles to identify and develop shorter lead time transmission upgrades and one 24 month planning cycle to provide sufficient time for the identification and development of longer lead time transmission upgrades that may be required to satisfy planning criteria.

Market Efficiency Process

PJM's Regional Transmission Expansion Plan (RTEP) process includes a market efficiency analysis. The stated purpose of the market efficiency analysis is to: determine which reliability based enhancements have economic benefit if accelerated; identify new transmission enhancements that result in economic benefits; and identify economic benefits associated with modification to existing RTEP reliability based enhancements that when modified would relieve one or more economic constraints. The PJM market efficiency analysis is badly flawed and results in concluding there are net benefits when there are not. PJM presents the RTEP market efficiency enhancements to the PJM Board, along with stakeholder input, for Board approval.

To be recommended to the PJM Board of Managers for approval, the relative benefits and costs of the economic based enhancement or expansion of the proposed project must reduce congestion on one or more constraints by at least one dollar, meet a ratio threshold of at least 1.25:1 and have an independent cost review, performed by PJM, if expected costs are over $50 million. PJM provides the review of a project with a projected cost of over $50 million using its own staff or outside consultants. PJM presents its findings to the TEAC where PJM's findings are reviewed by the stakeholders. While stakeholders can comment on the findings, PJM makes the final decision about what costs will be used for the purpose of calculating the benefit/cost ratio for the project. The benefit/cost ratio is the ratio of the present value of the total annual benefit for 15 years to the present value of the total annual cost for the first 15 years of the life of the enhancement or expansion.

The market efficiency process is comprised of a 12 month cycle and a 24 month cycle, both of which begin and end on the calendar year. The 12 month cycle is used for analysis of modifications and accelerations to approved RTEP projects only. The 24 month cycle is used for analysis of new economic transmission projects for years five through 15. This long-term proposal window takes place concurrently with the long-term proposal window for reliability projects.

PJM's first market efficiency analysis was performed in 2013, prior to Order 1000. The 2013 window was open from August 12, 2013, through September 26, 2013. This window accepted proposals to address historical congestion on 25 identified flowgates. PJM received 17 proposals from six entities. One project, submitted by an incumbent transmission owner, was approved by the PJM Board.

The first market efficiency cycle conducted under Order 1000 was performed during the 2014/2015 RTEP long term window. The 2014/2015 long term window was open from November 1, 2014, through February 28, 2015. This window accepted proposals to address historical congestion on 12 identified

108 The material in this section is based in part on the PJM Manual 14B: PJM Region Transmission Planning Process. See PJM. "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 58 (December 17, 2025).

flowgates. PJM received 93 proposals from 19 entities. Thirteen projects, all submitted by an incumbent transmission owner, were approved by the PJM Board.

The second market efficiency cycle was performed during the 2016/2017 RTEP long term window. The 2016/2017 long term window was open from November 1, 2016, through February 28, 2017. This window accepted proposals to address historical congestion on four identified flowgates. PJM received 96 proposals from 20 entities. Four projects, all submitted by an incumbent transmission owner, were approved by the PJM Board.

PJM also held an addendum 2016/2017 long term window. This 2016/2017 1A long term window was open from September 14, 2017, through September 28, 2017. This window accepted proposals to address historical congestion on one identified flowgate. PJM received three proposals from two entities. One project, submitted by an incumbent transmission owner, was approved by the PJM Board.

The fourth market efficiency cycle was performed for the 2018/2019 RTEP long term window. The 2018/2019 long term window was open from November 2, 2018, through March 15, 2019. This window accepted proposals to address historical congestion on one internal and three interregional flowgates. PJM received 33 proposals from 10 entities. One project, submitted by an incumbent transmission owner, was approved by the PJM Board to address the historical congestion on the internal flowgate, and one project, submitted by an incumbent transmission owner, was approved by the PJM Board to address the historical congestion on one of the interregional flowgates.[109]

The fifth market efficiency cycle was performed for the 2020/2021 RTEP long term window. The 2020/2021 RTEP long term window was open from November 11, 2020, through May 11, 2021. This window accepted proposals to address historical congestion on four internal flowgates. PJM received 24 proposals from seven entities. Four projects, all submitted by an incumbent transmission owner, were approved by the PJM Board.

109 No proposals effectively resolved the congestion on two of the three identified interregional market efficiency flowgates.

The sixth market efficiency cycle was performed during the 2022/2023 RTEP long term window. The 2022/2023 RTEP long term window was delayed until the reliability violations for the 2022 Window 3 (Dominion data center loads) could be addressed. On November 21, 2023, PJM requested that the Commission grant a waiver to extend the time for PJM to complete its annual review of the benefit/cost analysis associated with the market efficiency cycle.[110] PJM requested the waiver to remain in effect until PJM completes its 2023 annual review no later than the end of the second quarter of 2024. On December 21, 2023, The Commission approved the waiver request.[111] 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.

In February 2024, PJM completed the 2024/2025 market efficiency base case. In May 2024, PJM posted the 2024/2025 Market Efficiency planning assumptions. The long term market efficiency window opened on April 11, 2025, and closed on June 10, 2025. This window accepted proposals to address historical congestion on three identified flowgates (Museville-Smith Mountain 128 kV in AEP, West Point-Lanexa 115 kV in DOM and Garrett-Garrett Tap 115 kV in PN-APS). PJM received 14 proposals from five entities. Two projects, submitted by incumbent transmission owners, were approved by the PJM Board.[112] There were no projects selected for acceleration in the 2024/2025 market efficiency window.

The Benefit/Cost Evaluation

For an RTEP project to be recommended to the PJM Board of Managers for approval as a market efficiency project, the relative benefits and costs of the economic based enhancement or expansion must meet a benefit/cost ratio threshold of at least 1.25:1.

The total benefit of a project is calculated as the sum of the net present value of calculated energy market benefits and calculated reliability pricing model (RPM) benefits for a 15 year period, starting with the projected in service date

110 See *PJM Interconnection, L.L.C*, Docket No. ER24-477-000 (November 21, 2023).
111 185 FERC ¶61,212.
112 One of the three identified congestion drivers included in the market efficiency window (Garrett-Garrett Tap 115 kV) was addressed in the 2025 RTEP Window 1.

of the project. Depending on the type of project being evaluated PJM may measure benefits as reductions in estimated load charges and production costs in the energy market and reductions in estimated load capacity payments and in system capacity costs in the capacity market, but does not weight increases and decreases in benefits equally. There are significant issues with PJM's definition of benefits. 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. The change in production costs correctly measures the changes in cost to load that result from a project.

The energy market benefit analysis uses an energy market simulation tool that produces an hourly least-cost, security constrained market solution, including total operational costs, hourly LMPs, bus specific injections and bus specific withdrawals for each modeled year with and without the proposed RTEP project. Using the output from the model, PJM calculates changes in energy production costs and load energy payments.

PJM rules require that the energy market benefit simulation maintain sufficient capacity to meet load projections plus installed reserve margins over the 15 year study period.[113] In order to solve the cases, PJM must make assumptions about the existing and future generation to include in the model based on the need to serve load. In the event that the existing installed capacity is not sufficient to meet the load, PJM first adds generation from the queue with signed interconnection service agreements. If this is insufficient, PJM simply adds speculative new generation., based on assumptions about probable projects. In effect, this process could result in approving and building expensive transmission based on speculation about the location and type of capacity additions and load additions. The related impacts are exacerbated by the uncertainty about the actual additions of large data centers. This approach to benefit/cost analysis is inefficient and unsustainable.

The basis for load projections depends primarily on the projections of data center load which are highly uncertain and for which PJM has limited information about exact location and specifications. As made clear in the queue analysis, the actual addition of generation resources by type and location is also highly uncertain. The level of uncertainty makes the value of efficiency projects speculative and not an appropriate basis for investment in transmission projects.

The definition of the energy benefit analysis depends on whether the project is regional or subregional. A regional project is any project rated at or above 230 kV. A subregional project is any project rated at less than 230 kV. For a regional project, the energy benefit for each modeled year is equal to 50 percent of the change in system wide total system energy production costs with and without the project plus 50 percent of the change in zonal load payments with and without the project but, inexplicably, only for those zones where the project reduces the load payments and ignoring zones where the project increases load payments. For subregional projects, the calculation of benefits for each modeled year ignores any impact on system wide energy production costs and is instead based only the change in zonal load energy payments with and without the project, but again only for those zones where the project reduces the load energy payments and ignoring zones where the project increases load payments.

In both the regional and subregional analysis, changes in zonal load energy payments subtract the estimated value of any Auction Revenue Rights (ARR) that sink in that zone. An increase in ARR revenues that result from a project would reduce the benefits of that project to load. If done correctly and if ARRs returned 100 percent of congestion to load, the changes in load payments would equal the change in production costs. However, the calculated ARR credits in the benefit/cost analysis ignore any increases in ARR MW and include only the reduction in the estimated CLMP differences. Estimated ARR credits are calculated for each simulated year using the most recent planning year's actual ARR MW combined with the simulation's CLMP differences between ARR source and sink points. ARR MW are not adjusted to reflect any increase in ARR MW created by the RTEP upgrade. This means that the reduction in the ARR offset value is too large, the reduction in load payments is overstated, and the value of the proposed project is artificially increased.

113 See PJM Operating Agreement Schedule 61.7.7 (i).

The definition of the benefit in the RPM benefit analysis depends on whether the project is regional or subregional. For a regional project, the RPM benefit for each modeled year is equal to 50 percent of the change in system wide total system capacity payments with and without the project plus 50 percent of the change in zonal capacity payments with and without the project, including only those zones where the project reduced the capacity payments. For subregional projects, the reliability pricing model benefits for each modeled year ignores any impact on system wide total capacity payments and is equal to the change in zonal capacity payments with and without the project, including only those zones where the project reduced the capacity payments. As with the miscalculation of the congestion impacts in the energy market, this approach overstates the benefits.

The difference in the benefits calculation used in the regional and subregional benefit/cost threshold tests is related to how the direct costs of the transmission projects are allocated for approved regional and subregional projects. The costs of an approved regional project are allocated so that 50 percent of the total costs are allocated on a system wide load ratio share basis and the remaining 50 percent of the total costs are allocated to zones with projected energy market benefits and reliability pricing model benefits in proportion to those projected positive benefits. The costs of an approved subregional project are allocated so that the total costs of the project is allocated to zones with projected energy market benefits and reliability pricing model benefits in proportion to those projected positive benefits. The allocation will be incorrect to the extent that the benefits calculations are incorrect.

There are significant issues with PJM's benefit/cost analysis. The current rules governing benefit/cost analysis of competing transmission projects do not correctly measure the relative costs and benefits of transmission projects. PJM measures benefits as reductions in estimated load charges and production costs in the energy market and reductions in estimated load capacity payments in the capacity market, but PJM's analysis ignores any increases in costs. This means that PJM's benefit/cost analysis systematically overstates the benefits of transmission projects. ARR MW allocations are not adjusted to reflect any potential changes in ARR MW that result from the RTEP upgrade. This means that the reduction in the ARR offset value is too large, the ARR offset is too small, and the result is to artificially increase the value of the proposed project. The correct metric is the change in production costs. In addition, the current rules do not account for the fact that the benefits of projects are uncertain and highly sensitive to the modeling assumptions used, or for the fact that the project costs are nonbinding estimates, are not subject to cost caps and may significantly exceed the estimated costs. These flaws have contributed to PJM approving market efficiency projects with forecasted benefits that only appear to, but do not actually exceed the forecasted costs. In addition, there is no after the fact analysis to validate the planning assumptions and there is no data gathered on the actual costs and benefits that would permit such an analysis.

Recent proposals to use storage as a transmission asset (SATA) raises a number of additional concerns about PJM's benefit/cost analysis. Storage is a market asset and should not be owned by transmission owners. PJM should not be evaluating SATA at all without a decision from FERC that SATA is allowable in PJM. At present it is not allowed. PJM's benefit/cost analysis uses a 15 year forecast for purposes of evaluating benefits and costs of traditional transmission assets with an expected useful life of 50 years or more. Using the same 15 year horizon does not make sense for SATA resources with an expected useful life of 10 years or less, depending on use. In addition, there is no basis for assuming anything about the actual use of a transmission storage asset and therefor any imputed benefits. Using a 15 year benefit horizon exaggerates the forecasted benefit stream relative to the stream of benefits that could be produced over the expected useful life relative to traditional transmission assets. Further, the rules for how to account for the actual, and forecasted, revenues and charges for operating the SATA to provide transmission load relief have not been established. Without clear rules on how to allocate operational revenues and costs, and without detailed information about exactly the storage would be used, it is impossible to develop forecasted benefits and/or costs of a SATA project.

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 a ssets built under the competitive market paradigm. This is particularly noteworthy for the SATA case in which transmission owners would built market capacity assets under cost of service regulation that competes directly with market assets.

A significant flaw in PJM's benefit/cost analysis is that projected benefits are based on load forecasts which are currently dominated by projected large data center loads that are not verified by PJM and cannot be verified by PJM. That creates a bias towards finding transmission projects beneficial despite the fact that data center loads are imposing transmission costs on other customers as a result.

The MMU recommends that the market efficiency process be eliminated.

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. To qualify as an IMEP project, the project must be evaluated in a joint study process, qualify as an economic transmission enhancement in both PJM and MISO transmission expansion models and meet specific IMEP cost benefit criteria.[114] The allocation of costs to each RTO for IMEPs will be in proportion to the benefits received.

While the IMEP process is a joint effort, PJM and MISO perform their own analysis of benefits to their own system and each uses a different modeling approach and a different metric for determining the benefits of a proposed project. PJM uses the benefit/cost analysis used for its own internal market efficiency projects which will, by definition, overstate project benefits by ignoring areas where energy costs are increased. MISO, on the other hand, measures benefits as changes in projected system wide production cost caused by the project. The use of different approaches to measuring benefits is an issue when studying potential benefits of projects in a joint effort, and when using the defined benefits to allocate the costs of IMEP projects to each RTO. PJM's approach will over allocate the costs of IMEP projects to PJM members and under allocate costs to MISO members.

No interregional constraints were identified in either PJM's or MISO's regional processes. Therefore, an IMEP study was not required during the 2020/2021 IMEP cycle. No interregional constraints were identified in either PJM or MISO's regional processes. Therefore, an IMEP study was not required during the 2022/2023 IMEP cycle.

PJM and MISO began coordinating on interregional congestion issues to identify potential constraints to address in the 2024/2025 IMEP cycle. The joint regional planning committee (JRPC) decided to not initiate a coordinated system plan in 2025, and will instead prioritize the interregional transfer capability study (ITCS).

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. The TMEP process operates on a 12 month study schedule. To qualify as a TMEP project, the project must have an estimated in service date by the third summer peak season from the year the project was approved, have an estimated cost of less than $20 million and must have estimated benefits, based on the projected congestion reduction over a four year period that exceed the expected installed capacity cost of the proposed project.[115] [116] The TMEP process calculates congestion

114 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) <https://www.pjm.com/directory/merged-tariffs/miso-joa.pdf>.

115 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) <https://www.pjm.com/directory/merged-tariffs/miso-joa.pdf>.

116 On November 2, 2017, PJM submitted a compliance filing including additional revisions to the MISO-PJM JOA to include stakeholder feedback in the TMEP project selection process. See *PJM Interconnection, L.L.C*, Docket No. ER17-718-000, et al. (November 2, 2017).

and assigns congestion costs to load but fails to account for the offsetting value of ARRs and FTRs. The current rules incorrectly count congestion as a cost to load without accounting for how the congestion dollars are or are not returned to the load through ARRs and FTRs. The correct benefit metric is the change in production costs.

The benefit of a proposed TMEP project is calculated as the value of reducing congestion on the affected constraint over a four year period. PJM and MISO calculate the estimated value of eliminating congestion by calculating the average congestion for the two prior years prior and multiplying by four. Congestion is correctly calculated as the shadow price (difference in CLMP) times the market flow on the line.

The allocation of costs to each RTO for an approved TMEP project will be in proportion to the benefits, as calculated by PJM and MISO, received by that RTO.[117] The proportion of benefits is calculated using the change in the average shadow price of the constraint times the dfax to the affected downstream buses times the MW of load at the buses. This correctly identifies the proportion of the benefits that go to the load that would benefit from the project. Within an RTO, the RTO's share of the cost of the approved project is allocated to each transmission control area in proportion to the benefits received by each transmission control area.

PJM and MISO did not conduct a TMEP study in 2019. As a result of decreases in M2M congestion and the addition of transmission upgrades already in process that affect the top congested historical M2M flowgates, PJM and MISO did not conduct a TMEP study in 2020. PJM and MISO agreed to assess the impact of planned upgrades and congestion using an additional year of market data. As a result, PJM and MISO did not conduct a TMEP study in 2021. The 2022 TMEP study focused on 23 flowgates as potential TMEP projects. Of the 23 initial flowgates, 19 were eliminated due to their relationship with other existing reliability projects already included in PJM's RTEP or MISO's MTEP plans, or the identified congestion was caused by outages.[118] Two projects were eliminated after studies showed that congestion was not persistent in October 2022, and an additional project was eliminated in December 2022 after further studies showed congestion was not persistent, leaving one TMEP project (Powerton - Towerline 138 kV) that was approved for implementation by the PJM Board on February 15, 2023, and by the MISO Board on March 23, 2023.[119] [120] [121] For both 2023 and 2024, the RTOs decided not to initiate a Coordinated System Plan (CSP) study, and to continue to assess the impact of planned upgrades and congestion persistence with additional market data.

PJM and MISO began coordinating on interregional congestion issues to identify potential constraints to address in the 2024/2025 TMEP cycle. The joint regional planning committee (JRPC) decided to not initiate a coordinated system plan in 2025, and will instead prioritize the interregional transfer capability study (ITCS).

The PJM and MISO TMEP process for measuring the projected benefits of a TMEP transmission projects is flawed. The current rules incorrectly count congestion as a cost to load without accounting for how the congestion dollars are or are not returned to the load through ARRs and FTRs. The benefit of a TMEP transmission upgrade should be the expected difference in the total production cost of energy before and after the upgrade to all affected load. This measurement would include the change in expected LMP of all affected load before and after the upgrade, times the MW of load, plus the change in congestion dollars returned to the affected load before and after the upgrade. Congestion revenue returned to load is not a cost to the load, it is a credit against the overpayment of load payments compared to generation credits caused by the transmission constraint. Ignoring the return of congestion from ARRs/FTRs overstates the potential benefits of eliminating congestion through the TMEP upgrades, and ignores the value of smaller upgrades that may not eliminate a constraint, but may reduce the average cost of energy for load.

117 See *PJM Interconnection, L.L.C*, Docket No. ER17-729-000 (December 30, 2016).
118 See "Interregional Planning Update," presented at the August 9, 2022 meeting of the Transmission Expansion Advisory Committee. <https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20220809/item-01---interregional-planning-update.ashx>.
119 See "Interregional Planning Update," presented at the October 4, 2022 meeting of the Transmission Expansion Advisory Committee. <https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20221004/item-01----interregional-planning-update.ashx>.
120 See "PJM-MISO IPSAC," presented at the December 15, 2022 meeting of the PJM-MISO Inter-regional Planning Stakeholder Advisory Committee <https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/2022/20221215/ipsac-presentation.ashx>.
121 See "PJM-MISO IPSAC," presented at the December 11, 2023 meeting of the PJM-MISO Inter-regional Planning Stakeholder Advisory Committee <https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/2024/20240325/20240325-miso-seam-identified-issues-and-solutions-.ashx>.

PJM MISO Interregional Transfer Capability Study (ITCS)

PJM and MISO are performing an Interregional Transfer Capability Study (ITCS).[122] PJM and MISO are coordinating assumptions and models, but will not perform a joint study. The PJM/MISO Interregional Transfer Capability Study is part of PJM's and MISO's strategy to comply with FERC Order No. 1920. The ITCS study appears to mirror PJM's multi driver RTEP process in that it identifies several drivers (efficiency, reliability, transfer needs) for evaluating the value or need for a project, though neither MISO nor PJM provide any specificity as to the exact metrics for the evaluation of the benefits or costs within each identified driver, how the drivers will be weighted or how costs of potential projects should be allocated. The stated purpose of the PJM/MISO Interregional Transfer Capability Study is to allow PJM and MISO to consider needs, assumptions, cost allocations and analysis outside the limits of the existing PJM/MIO JOA/CSP process. The goal of the PJM and MISO ITCS is to identify opportunities to enhance transfer capability on an incremental basis over and above other JOA/CSP based studies.

The ITCS study is intended to look out through 2032. In its ITCS study, PJM plans to use a model that blends MISO planning models for MISO's footprint and a set of PJM's long-term planning assumptions for PJM's footprint. PJM is calling this a blended model. PJM's blended model will use the 2023 Regional Transmission Expansion Plan (RTEP) topology with 2022 RTEP Window 3 solutions, the PJM 2024 official Load Forecast, retirements due to federal regulations and state laws based on the Independent State Agencies Committee (ISAC) workbook and the assumption of sufficient replacement generation or storage for resource adequacy (i.e. to meet 1-in-10 Loss of Load Expectation) selected from interconnection requests and withdrawals. Although it is a feature of many transmission planning studies, simply assuming specific generating assets is not a reasonable way to do transmission planning with significant cost impacts on customers.

122 See PJM and MISO Interregional Capability Study (ICTS) FAQ <https://www.pjm.com/-/media/DotCom/planning/interregional-planning/pjm-and-miso-interregional-transfer-capability-study-faq.pdf>.

Preliminary results from the ITCS study identified various transfer, reliability and economic issues from both PJM and MISO.[123] PJM and MISO presented results and near and long term actions resulting from the ITCS study on June 25, 2025.[124] Interregional constraints were identified in the 2024/2025 PJM and MISO's joint ITCS analysis.[125] MISO opened a proposal window for the identified MISO and MISO intertie constraints that closed in May of 2025. MISO received 34 unique proposals from eight entities. Based on these proposals MISO developed 54 potential solution ideas for further evaluation by PJM and MISO. PJM and MISO have stated that they do not have a defined project type (and related cost allocation) to address all of the issues/benefits for the solutions identified in the ITCS process. PJM is reviewing the MISO potential solutions to see if any of the proposals are captured in the PJM RTEP reliability, RTEP Market Efficiency and/or the M-3 (Supplemental) process. In the case of any overlaps between RTEP and ITCS, PJM will consider the ITCS needs in RTEP solutions. PJM and MISO are planning for an update in the second quarter of 2026.

Expedited Interconnection Track (EIT)

On February 27, 2026, PJM filed revisions to the tariff to establish an expedited interconnection track (EIT) process for generating facilities.[126] The EIT was designed to expedite the interconnection of new generation that commits to firm commercial in service dates, has a commitment from the relevant siting authority (or a state executive officer in certain circumstances) to expedite consideration of applicable siting, and provides a pathway for new generation. The EIT process would allow PJM to consider up to 10 interconnection requests per calendar year on an expedited basis for large new or uprated resources. The EIT process is designed to help PJM address the need for additional capacity resources. The process is expected to take approximately 10 months for a resource to obtain a generation interconnection agreement (GIA).

123 See "PJM/MISO Interregional Transfer Capability Study," presented at the March 7, 2025 meeting of the PJM/MISO Interregional Planning Stakeholder Advisory Committee <https://www.pjm.com/-/media/DotCom/committees-groups/stakeholder-meetings/ipsac/2025/20250307/20250307-miso-pjm-ipsac-interregional-transfer-capability-study-itcs-to-pjm---working-draft.pdf>.

124 See PJM/MISO Interregional Transfer Capability Study (June 25, 2025) <https://www.pjm.com/-/media/DotCom/committees-groups/stakeholder-meetings/ipsac/2025/20250625/20250625-item-02---interregional-transfer-capability-study-update.pdf>.

125 See PJM/MISO Interregional Transfer Capability Study (June 25, 2025) <https://www.pjm.com/-/media/DotCom/committees-groups/stakeholder-meetings/ipsac/2025/20250625/20250625-item-02---interregional-transfer-capability-study-update.pdf>.

126 See PJM. Docket No. ER26-1563 (February 27, 2026).

Multi Driver Process

On September 12, 2014, PJM filed revisions to the tariff to include provisions allowing PJM to include multi driver projects in its regional transmission expansion plan.[127] When a transmission project addresses a combination of reliability, market efficiency and/or public policy objectives, it is termed a multi driver project. PJM may choose a solution using either the proportional multi driver method or the incremental multi driver method. The proportional method combines separate solutions that address reliability, economics and/or public policy into a single transmission enhancement or expansion project. The incremental method expands a proposed single driver solution to include one or more additional component(s) to address a combination of reliability, economic and/or public policy drivers.[128] On February 20, 2015, the Commission approved the tariff revisions with an effective date of November 12, 2014.[129]

On June 7, 2022, PJM opened its first multi driver proposal window. The window seeks to address reliability and market efficiency needs on three identified facilities. PJM accepted proposed solutions until August 8, 2022. PJM received 14 proposals from three entities. After conducting a cost review, a reliability analysis and a market efficiency analysis on the 14 proposals and a combination of the proposals, PJM proposed a combination of two proposals made by two companies (Project 644 + 908) as its preferred solution. The preferred solution has an estimated capital cost of $82.30 million with a PJM determined expected benefit/cost ratio of 1.99.[130] PJM shared its recommendation with MISO for their evaluation. MISO did not indicate any concern with the proposed solution. On February 7, 2023, the PJM Board approved the recommended solution (Project 644 + 908).

The benefit/cost analysis used in the multi driver review is the same flawed benefit/cost analysis that PJM uses for evaluating Market Efficiency projects. PJM's assumed benefit of the combined project was calculated as the sum of the present value of positive (energy cost reductions to some loads) effects of $169.8 million. The sum of the present value of negative effects (energy cost increases to other loads), which was ignored in the PJM calculation of benefits, was $149.1 million. The total benefit of the proposed multi driver project is therefore only $20.7 million, not the $169.8 asserted by PJM, even ignoring the use of changes in congestion rather than changes in production costs. Using the total positive and negative effects to compare to the net present value of costs in the PJM's analysis, the benefit/cost ratio is 0.24, not 1.99. All $149.1 million of the increases in energy costs (negative benefits) would be paid by load in the ComEd Zone. Based on the requirement of benefit/cost ratio of 1.25, the energy efficiency portion of the multi driver project should have been rejected.

State Agreement Approach (SAA)

PJM's State Agreement Approach (SAA) is a provision in PJM's Operating Agreement that allows states to propose transmission projects for inclusion in PJM's Regional Transmission Expansion Plan if the state agrees to assume the full cost of the proposed transmission projects. The purpose of the SAA is to allow states to pursue their public policy goals without imposing costs on other states. The SAA can also be used by a group of states that agree to a transmission project as part of a collaborative goal. Under the SAA, a state can elect to select the entity to complete the project or the states can request that PJM open a competitive window to seek transmission solutions from developers that address the required upgrades. SAA projects are classified as public policy baseline projects or as supplemental projects developed by the selected PJM Transmission Owner. The state decides whether to pursue a project that comes out of the SAA process.

Five states (Delaware, Maryland, North Carolina, Virginia and New Jersey) made a joint request to PJM to conduct a two phase study (The Offshore Wind Transmission Study) to determine reinforcements to the onshore grid to reliably deliver 6,416 to 17,016 of offshore wind plus additional RPS target requirements.[131] The phase one study, published on October 19, 2021, examined, at a high level, enhancements to the existing infrastructure needed to reliably integrate the proposed offshore wind generation, but did not

127 See PJM. Docket No. ER14-2864 (September 12, 2014).

128 See "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 58 (December 17, 2025).

129 150 FERC ¶ 61,117 (February 20, 2015).

130 See "2022 RTEP Multi-Driver Proposal Window No. 1," presented at the December 6, 2022 meeting of the Transmission Expansion Advisory Committee <https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20221206/item-07---multi-driver-proposal-window-update.ashx>.

131 See Offshore Wind Transmission Study: Phase 1 Results, October 19, 2021 (https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2021/20211019-offshore-wind-transmission-study-phase-1-results.pdf)

include any estimates of the costs of the transmission infrastructure needed. The phase 1 study did not consider any greenfield transmission solutions, instead using existing facilities as potential points on injection (POI) and existing transmission paths as locations for upgrades. The study considered six scenarios.

Scenario 1 focused on a short term window that assumed a wind injection total of 6,416 MW and RPS targets through 2027 with a projected cost of $627 million. Scenario 1 included generator deactivations that were announced as of October 1, 2020, and were included in PJM's RTEP base case that formed the basis of the study. The other scenarios (Scenario 2 through Scenario 6) were longer term studies that looked out through 2035. Scenario 2, with a projected cost of $2,461.4 million, assumed 14,416 MW of offshore wind capacity and the same generator deactivations assumed in Scenario 1. Scenarios 2 through 6 assumed 1,739 MW of additional deactivated generation in addition to what was modeled in Scenario 1 and 2. Scenario 3 was abandoned due to legislation being withdrawn that had required the retirement of specific units. Scenario 4 assumed an increase (relative to Scenario 1) of 2,600 MW additional offshore wind connecting to Virginia POI resulting in projected costs of $3,213.1 million in needed upgrades. Scenario 5 assumed a different POI for Scenario 1 New Jersey offshore wind and cost $2,591.8 million in expected upgrade costs. Scenario 6 removed 2,000 MW of New Jersey offshore wind from Scenario 2 resulting in $2,164.3 million in projected upgrade costs.

The states decided to not pursue a joint Phase 2 study.

Delaware Offshore Wind

Delaware does not have any offshore wind projects. Delaware is the point of interconnection for Maryland's MarWin and Momentum Wind offshore wind projects being developed by US Wind. In January 2025, US Wind entered into a contract with Delaware to provide 150,000 offshore renewable energy credits (ORECs) over the life of the two projects, which will be transferred to Delaware utilities to help them meet clean energy requirements. The MarWin and Momentum Wind projects will be the source of these credits. Both the MarWin and Momentum Wind projects are being developed in Maryland through the SAA process.

New Jersey State Agreement Approach (SAA) for Offshore Wind

In 2021, the New Jersey Board of Public Utilities (NJ BPU) initiated a proposal window under the SAA to meet New Jersey's goal of interconnecting up to 7,500 MW of offshore wind.[132] PJM received 80 proposals covering solutions that addressed onshore and offshore reliability criteria and transmission connections. The NJ BPU selected a proposal to interconnect 3,742 MW of offshore wind to central New Jersey at a total estimated cost for the project of $1.1 billion, with construction expected to start in 2027 and finish in 2029, with in service dates from December 2027 through June 2030. The costs for the NJ BPU offshore wind project would be recovered from customers in the state of New Jersey. On December 6, 2022, the PJM Board approved the BPU's proposal.

On October 31, 2023, Danish wind power developer Ørsted announced that it was canceling two major offshore wind projects, Ocean Wind 1 (1,100 MW) and Ocean Wind 2 (1,148 MW), that were planned off the coast of New Jersey. Prior this announcement, on September 22, 2023, Public Service Electric and Gas Company filed an application for an abandoned plant incentive to recover costs associated with the canceled wind projects.[133] The filing seeks "authorization for the ability to recover 100 percent of prudently incurred costs for certain transmission upgrades that PSE&G will construct in the event that the [offshore wind] transmission upgrades are abandoned or cancelled (in whole or in part) for reasons that are outside of PSE&G's control." Ørsted is taking a $2.9 billion impairment attributed to Ocean Wind 1.[134]

On March 31, 2026, only two New Jersey offshore wind projects remained, both in the serial queue and both suspended.

132 See PJM Operating Agreement, Schedule 6, Section 1.5.9
133 See *Public Service Electric and Gas Company*, Docket No. ER23-2916 (September 22, 2023).
134 Ørsted, Ørsted ceases development of its US offshore wind projects Ocean Wind 1 and 2, takes final investment decision on Revolution Wind, and recognises DKK 28.4 billion impairments (October 31, 2023) <*https://orsted.com/en/company-announcement-list/2023/10/oersted-ceases-development-of-its-us-offshore-wind-73751*>.

Maryland State Agreement Approach (SAA) for Offshore Wind

On December 5, 2024, the Maryland Public Service Commission (MD PSC) requested that PJM conduct analysis of Maryland's 8,500 MW offshore wind target, assuming three different point of interconnection scenarios, in response to the Maryland POWER Act of 2023. PJM provided the requested study on March 21, 2025.[135] On June 23, 2025, the Maryland Public Service Commission requested that PJM issue a competitive solicitation for proposals under the SAA process for onshore injection of 2,000 MW of offshore wind at Indian River by 2028 (DP&L), 1,500 MW of offshore wind at Cool Spring by 2030 (DP&L), 1,500 MW of offshore wind at Piney Grove by 2030 (DP&L), 1,500 MW of offshore wind at Nelson by 2030 (DP&L) and 2,000 MW of offshore wind at Calvert Cliffs by 2031 (PEPCO).[136] PJM is currently working with the MD PSC to draft a SAA study agreement, which must be filed and approved by the Federal Energy Regulatory Commission (FERC).

Maryland has three offshore wind projects. Of the three projects, two have been bid on. The first project, MarWin (300 MW), was won by US Wind and Skipjack Energy in 2017. The second project, Momentum Wind (808 MW), was won by US Wind and Skipjack Energy in 2021. The State of Maryland signed offtake agreements to purchase the output from two projects and awarded OREC (Offshore Renewable Energy Credits) to US Wind and Skipjack Energy. Skipjack Wind subsequently backed out due to financing issues and relinquished the ORECs it had been awarded. To replace Skipjack's share, Maryland opened bidding which US Wind won. US Wind will construct a 1,710-megawatt (MW) project developed in four phases that will consist of 114 15 MW turbines. Phase 1 has an expected commercial operation date of 2029 while Phases 2, 3, and 4 have an anticipated commercial operating date of December 2030, with the first year of the OREC schedules beginning in January 2031. The project plan calls for direct connections from the Maryland projects to substations along the shore of the state of Delaware.

The Maryland Offshore Wind Project (the MarWin and Momentum Wind phases) received federal approval for its Construction and Operations Plan (COP) as of December 3, 2024. In December 2025, the Trump administration ordered construction to stop on five major US offshore wind projects citing national security concerns, including The Maryland Offshore Wind Project. The developers of the five offshore projects (including US Wind) challenged the move in court and secured injunctions allowing work to continue. The projects were put on hold in September 2025 when the U.S. Bureau of Ocean Energy Management (BOEM) vacated the federal permit for the project.

On March 31, 2026, only two Maryland offshore wind projects remained, both in the serial queue and both suspended.

Virginia's Coastal Virginia Offshore Wind (CVOW)

The Coastal Virginia Offshore Wind (CVOW) project is owned and operated by Dominion Energy. The project consists of 176 wind turbine generators, three offshore substations and nine buried submarine cables that will connect the wind turbines to the State Military Reservation in Virginia Beach, Virginia. With the exception of the near shore portion of the submarine cable length (within 3 miles of shore), the offshore project components will be located in federal waters. The CVOW project, designed to provide 2,600 MW of offshore wind, was scheduled for completion in 2026.

On January 20, 2025, the Trump Administration issued an executive order that temporarily prevented "consideration of any area in the OCS for any new or renewed wind energy leasing for the purposes of generation of electricity or any other such use derived from the use of wind."[137] The order stated that "[n]othing in this withdrawal affects rights under existing leases in the withdrawn areas." The order called for the Secretary of the Interior to conduct a comprehensive review of the ecological, economic, and environmental necessity of terminating or amending any existing wind energy leases. On December 8, 2025, a federal judge vacated the executive order.

On December 22, 2025, the US Interior Department, Bureau of Energy Management, issued a 90 day suspension of five offshore wind leases,

135 See Maryland Offshore Wind Information Study Results, (March 21, 2025) <https://webpscxb.psc.state.md.us/DMS/case/9800>.
136 See Maryland PSC Request Letter, (June 23, 2025) <https://webpscxb.psc.state.md.us/DMS/case/9800>.

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

including the lease associated with the CVOW project. Dominion filed a lawsuit on December 23, 2025, asking the court to reject the pause.[138] As of December 31, 2025, work on the CVOW was on pause.[139]

On March 31, 2026, only three Dominion offshore wind projects remained, all in the cycle queue and all under construction. On March 23, 2025, the first commercial turbine (14.7 MW) of Dominion's Coastal Virginia Offshore Wind project started producing power. As of March 31, 2026, two turbines of the Coastal Virginia Offshore Wind project have been constructed. The second turbine is not currently producing power. The entire project is scheduled to be completed in 2027.

Long Term Regional Transmission Planning

On May 13, 2024, the Commission issued Order No. 1920 which requires public utility transmission providers to engage in long-term regional transmission planning over a 20-year planning horizon, develop long-term scenarios to identify long-term transmission needs and enable the identification and evaluation of transmission facilities to meet those transmission needs. Order No. 1920 also requires transmission providers to determine a cost allocation method for long-term regional transmission facilities, make other reforms to enhance transparency in local transmission planning, to correctly size transmission projects and include interregional transmission coordination to support the development of cost-effective projects.[140]

On November 21, 2024, the Commission issued Order No. 1920-A.[141] Order No. 1920-A significantly expanded the role of States in the long-term regional transmission planning. Order No. 1920-A requires states' input into regional transmission planning and cost allocation processes, both in the transmission providers' development of Order No. 1920 compliance filings and the ongoing implementation of these reforms in the future. Order No. 1920-A also increases the states' role in: (i) developing long term scenarios; (ii) requesting additional scenarios beyond the three Long-Term Scenarios required by Order No. 1920; (iii) developing the evaluation processes and criteria for selecting new transmission facilities in the long-term regional transmission; (iv) developing cost allocation approaches for selected transmission facilities; and (v) voluntary funding opportunities.

PJM requested that the Commission extend PJM's deadline to comply with Order No. 1920's compliance directives by six months, (to December 12, 2025), while leaving the implementation deadline of two years after the initial due date of the compliance filing (June 12, 2027) unchanged. The extension was requested to accommodate the States' broader role required by Order No. 1920-A in developing Order No. 1920-compliant Long-Term Regional Transmission Planning protocols.[142] On December 12, 2025, PJM submitted its compliance filing.[143]

Supplemental Transmission Projects

Supplemental projects are asserted 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."[144] Attachment M-3 of the PJM OATT defines the process that Transmission Owners (TO) must follow in adding Supplemental Projects in their local plan.

The M-3 Process requires TOs to present the criteria, assumptions and models that they will use to plan and identify Supplemental Projects on a yearly basis. The criteria identified for Supplemental Projects are very broad and include: equipment material condition, performance and risk, operational flexibility and efficiency, infrastructure resilience, customer service or other, as well as asset management.

While the identification of the criteria violations and solutions are reviewed, and stakeholders have the opportunity to comment, the solution that is submitted

138 Case No. 2:25-cv-00830-JKW-LRL (USDC E.D. Va.).
139 See Monthly Mariner's Update Costal Virginia Offshore Wind (CVOW), (January 1, 2026) <(https://coastalvawind.com/resources/docs/20260101_january_mariner_update.pdf>.
140 See *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation, Order No. 1920*, 187 FERC ¶ 61,068 (2022).
141 See *Order on rehearing and clarification, Order No. 1920-A*, 189 FERC ¶ 61,126 (2024).
142 See PJM Interconnection, L.L.C., Docket No. RM21-17-000 (December 20, 2024).
143 See PJM Interconnection, L.L.C., Docket No. ER26-750-000 (December 12, 2025).
144 See PJM. Planning. "Transmission Construction Status," (Accessed on March 31, 2026) <https://www.pjm.com/planning/project-construction>.

in the Local Plan is the Transmission Owner's decision. PJM conducts a do no harm analysis to ensure the Supplemental Projects do not negatively affect the reliability of the system. Supplemental Projects are ultimately included in PJM's Regional Transmission Expansion Plan and are allocated 100 percent to the zone in which the transmission facilities are located. Supplemental Projects may displace projects that would have otherwise been implemented through the RTEP process.

Supplemental projects are currently exempt from the Order No. 1000 competitive process.[145] Transmission owners have a clear incentive to increase investments in rate base given that transmission owners are paid for these projects on a cost of service basis.

Figure 12-6 shows the latest cost estimate of all baseline and supplemental projects by expected in service year. Baseline projects are RTEP projects needed for reliability. FERC Order No. 890 was issued on February 16, 2007, and implemented in PJM starting in 2008. Order No. 890 required Transmission Providers to participate in a coordinated, open and transparent planning process. Prior to the implementation of Order No. 890, there were transmission projects planned by transmission owners and included in the PJM planning models that were not included in the totals shown in Figure 12-6, Table 12-82 and Table 12-83 because PJM did not track or report such projects. There has been a significant increase in supplemental projects coincident with the implementation of Order No. 890 starting in 2008 and the competitive planning process introduced by FERC Order No. 1000 starting in 2011.

PJM's data collection, management and retention related to transmission spending of all types is inadequate and needs a significant upgrade. The failure to collect data on estimated and final project costs makes it impossible to track transmission project costs for all project types. 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.

145 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).

Figure 12-6 Cost estimate of baseline and supplemental projects by expected in service year: January 1, 1998 through December 31, 2026

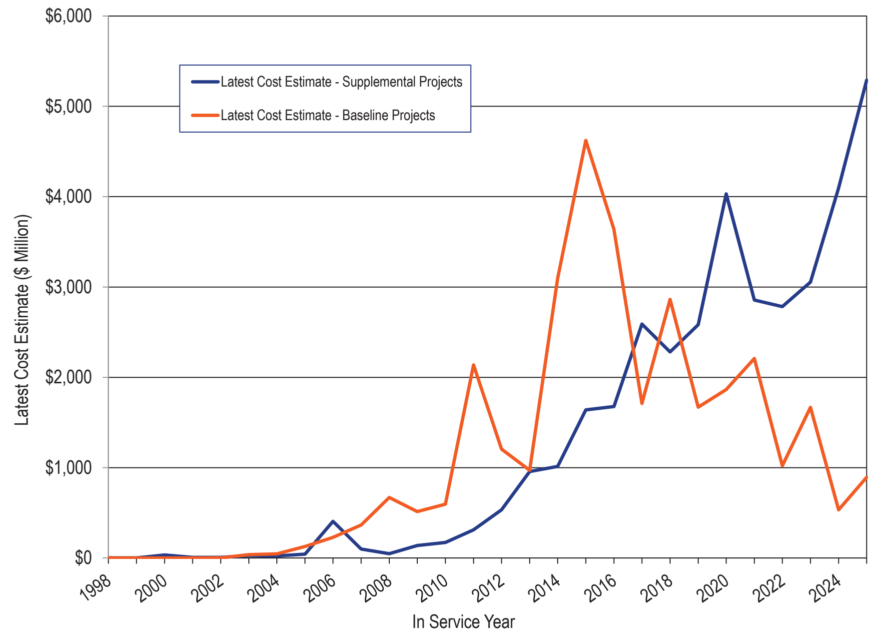


Table 12-82 shows the number of supplemental projects by expected in service year for each transmission zone. The average number of supplemental projects in each expected in service year increased by 1,155.0 percent, from 20 for years 1998 through 2007 (pre Order No. 890) to 251 for years 2008 through 2026 (post Order No. 890). As of March 31, 2026, there were 1,792 supplemental projects with expected in service dates between January 1, 2026 and December 31, 2036.

Table 12-82 Number of supplemental projects by expected in service year and zone: 1998 through 2050

Year	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	NEET	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
1998	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1.67	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1.67
1999	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.77	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.77
2000	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$32.94	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$32.94
2001	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$6.79	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$6.79
2002	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$6.99	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$6.99
2003	$7.42	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$8.77	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$9.60	$0.00	$0.00	$0.00	$0.00	$25.79
2004	$4.45	$0.00	$0.00	$10.00	$0.00	$0.00	$0.82	$0.00	$0.00	$0.00	$0.00	$7.33	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$22.60
2005	$4.06	$14.66	$0.00	$10.12	$0.00	$0.00	$2.57	$0.00	$0.00	$0.00	$0.02	$10.98	$0.00	$0.00	$0.00	$0.00	$0.00	$0.50	$0.00	$0.00	$0.00	$0.00	$0.00	$42.91
2006	$4.03	$309.70	$0.00	$0.93	$0.00	$0.00	$48.93	$0.00	$0.00	$0.00	$0.00	$11.62	$0.00	$6.00	$0.00	$0.00	$0.00	$0.00	$1.50	$0.00	$4.63	$18.80	$0.00	$406.14
2007	$0.56	$2.06	$0.00	$9.85	$0.00	$37.61	$4.64	$0.00	$0.00	$31.75	$0.00	$9.71	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.34	$2.28	$0.00	$98.80
2008	$2.36	$0.00	$0.00	$12.03	$0.00	$0.45	$7.61	$0.00	$0.00	$7.00	$14.01	$2.27	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1.59	$0.00	$0.00	$47.32
2009	$0.77	$0.90	$0.00	$12.22	$0.00	$5.00	$21.11	$0.00	$0.00	$19.60	$2.12	$7.35	$0.00	$0.00	$0.00	$0.00	$0.00	$48.10	$2.73	$0.00	$0.16	$17.60	$0.00	$137.66
2010	$0.00	$34.36	$0.00	$12.13	$0.00	$18.90	$1.38	$0.00	$0.00	$34.45	$14.98	$0.00	$0.00	$0.03	$4.58	$0.00	$0.00	$31.80	$0.00	$0.00	$1.86	$17.72	$0.00	$172.19
2011	$0.00	$37.60	$0.00	$9.30	$0.00	$0.00	$1.00	$0.00	$0.00	$16.72	$85.67	$0.00	$0.00	$1.16	$0.00	$0.00	$0.00	$113.30	$0.00	$0.00	$11.87	$34.60	$0.00	$311.22
2012	$0.00	$46.00	$0.00	$5.12	$0.35	$2.20	$12.60	$0.00	$26.06	$11.60	$165.74	$0.99	$0.00	$6.61	$0.00	$0.00	$0.00	$12.60	$0.00	$0.00	$19.66	$223.01	$0.00	$532.54
2013	$3.15	$134.93	$0.00	$1.10	$33.68	$0.00	$59.25	$0.00	$9.93	$79.10	$25.03	$0.99	$0.00	$0.05	$4.10	$0.00	$0.00	$22.50	$0.00	$2.40	$76.70	$503.72	$0.00	$956.63
2014	$8.03	$387.00	$0.00	$5.97	$58.70	$21.20	$60.37	$0.00	$2.43	$14.90	$88.61	$5.96	$0.72	$5.60	$0.00	$0.00	$0.00	$13.30	$1.30	$0.00	$33.47	$305.30	$0.00	$1,012.86
2015	$3.73	$237.45	$0.00	$3.80	$21.90	$2.00	$376.00	$0.00	$14.12	$4.53	$113.53	$13.06	$1.22	$0.30	$0.00	$0.00	$0.00	$33.80	$0.00	$42.50	$50.17	$721.91	$0.00	$1,640.02
2016	$74.54	$84.13	$0.00	$18.40	$182.70	$0.00	$308.15	$0.00	$15.13	$26.95	$40.68	$26.60	$0.25	$0.00	$2.37	$0.00	$0.00	$86.40	$0.40	$7.80	$58.76	$742.48	$0.00	$1,675.74
2017	$66.28	$648.74	$0.00	$8.60	$164.45	$0.09	$145.97	$0.00	$64.31	$3.62	$104.25	$92.29	$2.21	$0.00	$14.70	$0.00	$0.00	$0.00	$8.30	$12.00	$264.34	$988.92	$0.00	$2,589.07
2018	$66.55	$818.03	$0.00	$14.60	$42.12	$4.08	$80.94	$0.00	$69.80	$3.13	$162.94	$68.94	$10.87	$0.00	$0.00	$0.00	$0.00	$47.60	$0.00	$156.00	$197.34	$537.85	$0.00	$2,280.79
2019	$64.30	$1,114.64	$0.00	$11.97	$190.40	$76.55	$90.19	$0.30	$90.69	$0.30	$90.14	$33.55	$23.67	$0.90	$62.30	$0.00	$0.00	$2.00	$75.80	$0.00	$298.00	$356.41	$0.00	$2,582.11
2020	$59.58	$920.44	$0.00	$0.30	$115.41	$62.58	$78.09	$14.36	$72.06	$6.40	$258.72	$39.50	$25.61	$2.30	$23.10	$0.00	$0.00	$2.40	$72.70	$102.70	$215.29	$1,959.38	$0.00	$4,030.92
2021	$86.54	$1,195.03	$0.00	$9.50	$184.21	$32.52	$140.90	$17.79	$117.39	$18.90	$98.40	$0.00	$25.67	$47.84	$85.89	$0.00	$0.00	$73.40	$63.48	$0.00	$197.67	$460.84	$0.00	$2,855.97
2022	$81.40	$805.01	$0.00	$19.32	$205.52	$190.13	$147.60	$21.46	$64.32	$45.00	$194.60	$9.38	$22.12	$34.84	$127.04	$0.00	$0.00	$72.80	$59.79	$0.00	$231.92	$450.83	$0.00	$2,783.08
2023	$59.10	$852.55	$0.00	$49.09	$160.41	$18.35	$48.34	$25.60	$112.27	$0.00	$333.30	$87.57	$29.77	$3.41	$130.50	$68.77	$0.00	$24.40	$20.07	$218.84	$183.73	$628.26	$0.00	$3,054.33
2024	$87.60	$1,399.86	$20.00	$69.91	$199.70	$23.84	$219.60	$202.60	$31.73	$0.00	$498.66	$95.30	$61.42	$87.73	$103.80	$0.00	$0.00	$173.57	$63.18	$5.12	$235.95	$517.54	$0.00	$4,097.11
2025	$40.00	$1,999.45	$18.00	$116.70	$490.88	$123.82	$15.35	$58.75	$109.56	$50.55	$414.41	$0.00	$62.66	$83.21	$194.25	$0.00	$0.00	$13.39	$152.16	$594.13	$353.45	$398.90	$0.00	$5,289.62
2026	$14.08	$2,237.71	$25.54	$265.66	$344.28	$427.43	$547.05	$123.72	$127.42	$0.00	$1,271.48	$63.40	$14.93	$169.16	$149.17	$0.00	$0.00	$25.90	$65.37	$13.30	$498.45	$262.20	$0.00	$6,646.25
2027	$91.30	$1,381.80	$78.50	$187.58	$471.96	$0.00	$745.90	$124.60	$60.15	$168.50	$1,269.34	$14.10	$94.65	$188.23	$168.33	$0.00	$0.00	$54.40	$197.31	$4.96	$1,028.23	$407.92	$0.00	$6,737.76
2028	$83.06	$1,190.94	$66.60	$158.54	$449.53	$407.25	$576.90	$52.50	$89.65	$0.00	$1,071.95	$73.78	$31.13	$102.74	$153.70	$0.00	$4.40	$61.40	$247.00	$0.00	$523.56	$656.15	$0.00	$6,000.78
2029	$181.67	$697.90	$0.00	$208.84	$142.22	$84.30	$0.00	$46.20	$84.43	$0.00	$1,007.02	$37.50	$53.20	$44.26	$58.75	$0.00	$0.00	$36.00	$158.50	$1.00	$311.90	$987.00	$0.00	$4,140.69
2030	$271.30	$537.86	$29.00	$38.80	$49.50	$0.00	$0.00	$74.30	$0.00	$0.00	$411.55	$0.00	$37.76	$16.92	$0.00	$0.00	$0.00	$0.00	$0.00	$22.00	$58.75	$107.70	$0.00	$1,655.44
2031	$31.50	$942.58	$0.00	$18.80	$453.70	$276.00	$0.00	$0.00	$11.00	$0.00	$0.00	$42.50	$0.00	$8.00	$0.00	$0.00	$0.00	$82.00	$21.40	$0.00	$0.00	$0.00	$0.00	$1,887.48
2032	$84.00	$285.05	$0.00	$5.38	$0.00	$0.00	$0.00	$0.00	$5.30	$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	$379.73
2033	$0.00	$0.00	$0.00	$1.90	$0.00	$0.00	$0.00	$0.00	$0.00	$30.40	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$242.17	$0.00	$0.00	$274.47
2034	$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	$443.00	$0.00	$89.40	$0.00	$0.00	$532.40
2035	$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
2036	$0.00	$166.60	$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	$166.60
2037	$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
2038	$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
2039	$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
2040	$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
2041	$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
2042	$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
2043	$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
2044	$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
2045	$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
2046	$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
2047	$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
2048	$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
2049	$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
2050	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$7.50	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$7.50
Total	$1,481.36	$18,482.98	$237.64	$1,296.46	$3,961.62	$1,814.30	$3,741.26	$762.18	$1,177.75	$573.40	$7,744.65	$812.60	$497.86	$809.29	$1,282.58	$68.77	$4.40	$1,031.56	$1,663.59	$1,182.75	$5,189.36	$11,307.32	$0.00	$65,123.68

Table 12-83 shows the latest cost estimate of supplemental projects by expected in service year for each transmission zone. The average cost of supplemental projects in each expected in service year increased by 3,311.0 percent, from $64.5 million for years 1998 through 2007 (pre Order No. 890) to $2.2 billion for years 2008 through 2026 (post Order No. 890). As of March 31, 2026, the 1,792 supplemental projects with expected in service dates between January 1, 2026 and December 31, 2036, have a total cost estimate of $28.4 billion.

Table 12-83 Latest cost estimate by expected in service year and zone ($ millions): 1998 through 2050

Year	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	NEET	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
1998	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1.67	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1.67
1999	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.77	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.77
2000	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$32.94	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$32.94
2001	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$6.79	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$6.79
2002	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$6.99	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$6.99
2003	$7.42	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$8.77	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$9.60	$0.00	$0.00	$0.00	$0.00	$25.79
2004	$4.45	$0.00	$0.00	$10.00	$0.00	$0.00	$0.82	$0.00	$0.00	$0.00	$0.00	$7.33	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$22.60
2005	$4.06	$14.66	$0.00	$10.12	$0.00	$0.00	$2.57	$0.00	$0.00	$0.00	$0.02	$10.98	$0.00	$0.00	$0.00	$0.00	$0.00	$0.50	$0.00	$0.00	$0.00	$0.00	$0.00	$42.91
2006	$4.03	$309.70	$0.00	$0.93	$0.00	$0.00	$48.93	$0.00	$0.00	$0.00	$0.00	$11.62	$0.00	$6.00	$0.00	$0.00	$0.00	$0.00	$1.50	$0.00	$4.63	$18.80	$0.00	$406.14
2007	$0.56	$2.06	$0.00	$9.85	$0.00	$37.61	$4.64	$0.00	$0.00	$31.75	$0.00	$9.71	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.34	$2.28	$0.00	$98.80
2008	$2.36	$0.00	$0.00	$12.03	$0.00	$0.45	$7.61	$0.00	$0.00	$7.00	$14.01	$2.27	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1.59	$0.00	$0.00	$47.32
2009	$0.77	$0.90	$0.00	$12.22	$0.00	$5.00	$21.11	$0.00	$0.00	$19.60	$2.12	$7.35	$0.00	$0.00	$0.00	$0.00	$0.00	$48.10	$2.73	$0.00	$0.16	$17.60	$0.00	$137.66
2010	$0.00	$34.36	$0.00	$12.13	$0.00	$18.90	$1.38	$0.00	$0.00	$34.45	$14.98	$0.00	$0.00	$0.03	$4.58	$0.00	$0.00	$31.80	$0.00	$0.00	$1.86	$17.72	$0.00	$172.19
2011	$0.00	$37.60	$0.00	$9.30	$0.00	$0.00	$1.00	$0.00	$0.00	$16.72	$85.67	$0.00	$0.00	$1.16	$0.00	$0.00	$0.00	$113.30	$0.00	$0.00	$11.87	$34.60	$0.00	$311.22
2012	$0.00	$46.00	$0.00	$5.12	$0.35	$2.20	$12.60	$0.00	$26.06	$11.60	$165.74	$0.99	$0.00	$6.61	$0.00	$0.00	$0.00	$12.60	$0.00	$0.00	$19.66	$223.01	$0.00	$532.54
2013	$3.15	$134.93	$0.00	$1.10	$33.68	$0.00	$59.25	$0.00	$9.93	$79.10	$25.03	$0.99	$0.00	$0.05	$4.10	$0.00	$0.00	$22.50	$0.00	$2.40	$76.70	$503.72	$0.00	$956.63
2014	$8.03	$387.00	$0.00	$5.97	$58.70	$21.20	$60.37	$0.00	$2.43	$14.90	$88.61	$5.96	$0.72	$5.60	$0.00	$0.00	$0.00	$13.30	$1.30	$0.00	$33.47	$305.30	$0.00	$1,012.86
2015	$3.73	$237.45	$0.00	$3.80	$21.90	$2.00	$376.00	$0.00	$14.12	$4.53	$113.53	$13.06	$1.22	$0.30	$0.00	$0.00	$0.00	$33.80	$0.00	$42.50	$50.17	$721.91	$0.00	$1,640.02
2016	$74.54	$84.13	$0.00	$18.40	$182.70	$0.00	$308.15	$0.00	$15.13	$26.95	$40.68	$26.60	$0.25	$0.00	$2.37	$0.00	$0.00	$86.40	$0.40	$7.80	$58.76	$742.48	$0.00	$1,675.74
2017	$66.28	$648.74	$0.00	$8.60	$164.45	$0.09	$145.97	$0.00	$64.31	$3.62	$104.25	$92.29	$2.21	$0.00	$14.70	$0.00	$0.00	$0.00	$8.30	$12.00	$264.34	$988.92	$0.00	$2,589.07
2018	$66.55	$818.03	$0.00	$14.60	$42.12	$4.08	$80.94	$0.00	$69.80	$3.13	$162.94	$68.94	$10.87	$0.00	$0.00	$0.00	$0.00	$47.60	$0.00	$156.00	$197.34	$537.85	$0.00	$2,280.79
2019	$64.30	$1,114.64	$0.00	$11.97	$190.40	$76.55	$90.19	$0.30	$90.69	$0.30	$90.14	$33.55	$23.67	$0.90	$62.30	$0.00	$0.00	$2.00	$75.80	$0.00	$298.00	$356.41	$0.00	$2,582.11
2020	$59.58	$920.44	$0.00	$0.30	$115.41	$62.58	$78.09	$14.36	$72.06	$6.40	$258.72	$39.50	$25.61	$2.30	$23.10	$0.00	$0.00	$2.40	$72.70	$102.70	$215.29	$1,959.38	$0.00	$4,030.92
2021	$86.54	$1,195.03	$0.00	$9.50	$184.21	$32.52	$140.90	$17.79	$117.39	$18.90	$98.40	$0.00	$25.67	$47.84	$85.89	$0.00	$0.00	$73.40	$63.48	$0.00	$197.67	$460.84	$0.00	$2,855.97
2022	$81.40	$805.01	$0.00	$19.32	$205.52	$190.13	$147.60	$21.46	$64.32	$45.00	$194.60	$9.38	$22.12	$34.84	$127.04	$0.00	$0.00	$72.80	$59.79	$0.00	$231.92	$450.83	$0.00	$2,783.08
2023	$59.10	$852.55	$0.00	$49.09	$160.41	$18.35	$48.34	$25.60	$112.27	$0.00	$333.30	$87.57	$29.77	$3.41	$130.50	$68.77	$0.00	$24.40	$20.07	$218.84	$183.73	$628.26	$0.00	$3,054.33
2024	$87.60	$1,399.86	$20.00	$69.91	$199.70	$23.84	$219.60	$202.60	$31.73	$0.00	$498.66	$95.30	$61.42	$87.73	$103.80	$0.00	$0.00	$173.57	$63.18	$5.12	$235.95	$517.54	$0.00	$4,097.11
2025	$40.00	$1,999.45	$18.00	$116.70	$490.88	$123.82	$15.35	$58.75	$109.56	$50.55	$414.41	$0.00	$62.66	$83.21	$194.25	$0.00	$0.00	$13.39	$152.16	$594.13	$353.45	$398.90	$0.00	$5,289.62
2026	$14.08	$2,237.71	$25.54	$265.66	$344.28	$427.43	$547.05	$123.72	$127.42	$0.00	$1,271.48	$63.40	$14.93	$169.16	$149.17	$0.00	$0.00	$25.90	$65.37	$13.30	$498.45	$262.20	$0.00	$6,646.25
2027	$91.30	$1,381.80	$78.50	$187.58	$471.96	$0.00	$745.90	$124.60	$60.15	$168.50	$1,269.34	$14.10	$94.65	$188.23	$168.33	$0.00	$0.00	$54.40	$197.31	$4.96	$1,028.23	$407.92	$0.00	$6,737.76
2028	$83.06	$1,190.94	$66.60	$158.54	$449.53	$407.25	$576.90	$52.50	$89.65	$0.00	$1,071.95	$73.78	$31.13	$102.74	$153.70	$0.00	$4.40	$61.40	$247.00	$0.00	$523.56	$656.15	$0.00	$6,000.78
2029	$181.67	$697.90	$0.00	$208.84	$142.22	$84.30	$0.00	$46.20	$84.43	$0.00	$1,007.02	$37.50	$53.20	$44.26	$58.75	$0.00	$0.00	$36.00	$158.50	$1.00	$311.90	$987.00	$0.00	$4,140.69
2030	$271.30	$537.86	$29.00	$38.80	$49.50	$0.00	$0.00	$74.30	$0.00	$0.00	$411.55	$0.00	$37.76	$16.92	$0.00	$0.00	$0.00	$0.00	$0.00	$22.00	$58.75	$107.70	$0.00	$1,655.44
2031	$31.50	$942.58	$0.00	$18.80	$453.70	$276.00	$0.00	$0.00	$11.00	$0.00	$0.00	$42.50	$0.00	$8.00	$0.00	$0.00	$0.00	$82.00	$21.40	$0.00	$0.00	$0.00	$0.00	$1,887.48
2032	$84.00	$285.05	$0.00	$5.38	$0.00	$0.00	$0.00	$0.00	$5.30	$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	$379.73
2033	$0.00	$0.00	$0.00	$1.90	$0.00	$0.00	$0.00	$0.00	$0.00	$30.40	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$242.17	$0.00	$0.00	$274.47
2034	$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	$443.00	$0.00	$89.40	$0.00	$0.00	$532.40
2035	$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
2036	$0.00	$166.60	$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	$166.60
2037	$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
2038	$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
2039	$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
2040	$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
2041	$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
2042	$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
2043	$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
2044	$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
2045	$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
2046	$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
2047	$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
2048	$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
2049	$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
2050	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$7.50	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$7.50
Total	$1,481.36	$18,482.98	$237.64	$1,296.46	$3,961.62	$1,814.30	$3,741.26	$762.18	$1,177.75	$573.40	$7,744.65	$812.60	$497.86	$809.29	$1,282.58	$68.77	$4.40	$1,031.56	$1,663.59	$1,182.75	$5,189.36	$11,307.32	$0.00	$65,123.68

On September 28, 2023, the Office of Ohio Consumers' Counsel filed a complaint regarding the impact of the volume and costs of supplemental projects on consumers. The complaint requests that the Commission develop a mechanism, to be included in the PJM Tariff and Operating Agreement, whereby "FERC would review the need, prudence and cost-effectiveness of local transmission projects in Ohio." The complaint also requests the Commission to appoint an Independent Transmission Monitor (ITM) to assist "in reviewing the planning, need, prudence and cost-effectiveness of local transmission projects for consumers in Ohio", and to "consider precluding the Ohio Transmission Utilities from using formula rates for establishing transmission rates."[146] The Office of Ohio Consumers' Counsel's complaint is pending.

On December 19, 2024, a group of consumer interests filed against multiple transmission owners and RTOs/ISOs.[147] The complaint alleges that provisions in the tariffs of the transmission owning utilities and the RTOs/ISOs inappropriately authorize individual transmission owners to plan facilities rated at 100 kilovolts kV and above without regard to efficiency or cost-effectiveness. The complaint does not challenge the rates for any specific locally planned projects, but, rather, alleges that the cumulative effect of tariff provisions allowing local planning of transmission projects rated at 100 kV and above results in unjust and unreasonable transmission rates.[148] The complaint requests issuance of an order that, for transmission facilities rated at 100 kV and above, requires: (i) removal of planning from transmission owner tariffs (and RTO tariffs that confirm such transmission owner planning); (ii) amendment of regional planning tariffs to require that all planning be done at the regional or interregional level (specifying facilities reaching the end of operational life); and (iii) amendment of regional planning tariffs be to require that the regional planning within the existing Order No. 1000 regions be conducted by independent transmission system planners.[149] The complaint recommends that independent transmission planners be structured similar to independent market monitors or be included in an expanded market monitoring function.[150] The consumer interests' planning complaint is pending.

The MMU recommends, to increase the role of competition, that the exemption of supplemental projects from the Order No. 1000 competitive process be terminated.

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. Under the current process, end of life transmission projects are not subject to the RTEP open window process and have become a form of supplemental project that is exempt from competition under the existing rules.[151]

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.

Competitive Planning Process Exclusions

There are several project types that are currently exempt from the competitive planning process. These project types include:

- **Immediate Need Exclusion**. If the violation needs to be resolved within three years or less, all such projects are excluded from competition. The local Transmission Owner is the Designated Entity.[152]

  On October 17, 2019, the Commission issued an Order Instituting Section 206 Proceedings to determine if RTOs have implemented the exemption in a manner consistent with the Commission's directives under Order

146 See Office of the Ohio Consumers' Counsel v. PJM, et al., Docket No. EL23-105 (September 28, 2023).
147 See Industrial Energy Consumers of America v. PJM, et al., Docket No. EL25-44-000 (December 19, 2024).
148 *Id.* at 11.
149 *Id.* at 42–43.
150 *Id.*, Attachment C (Declaration of Michael A. Giberson) at 36:11–37:8.
151 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).
152 See OA Schedule 6 § 1.5.8(m).

1000.[153] Some supplemental projects are in this category. In a decision issued August 19, 2022, the U.S. Court of Appeals for the D.C Circuit found that FERC reasonably approved MISO's Immediate Need Reliability Exception.[154] The Court rejected arguments challenging the MISO rule because (i) the definition of projects eligible for the exception was insufficiently limited and (ii) the rule allows for designating the incumbent developer before posting of the basis for the exception.[155] The decision was largely based on deference to FERC expertise.[156]

- **Below 200kV**. All projects at voltages less than 200kV are excluded from competition. The local Transmission Owner is the Designated Entity.[157] Some supplemental projects are in this category.
- **Substation Equipment**. If the limiting element(s) is substation equipment, such projects are excluded from competition. The local Transmission Owner is the Designated Entity.[158] Some supplemental projects are in this category.

While the PJM Operating Agreement defines the Designated Entity for projects that are excluded from the competitive planning process, neither the PJM Operating Agreement nor the various commission orders on transmission competition prohibit PJM from permitting competition to provide financing for such projects. 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. In addition, the criteria for and need for all exclusions from the competitive process should be reviewed. There does not appear to be any market reason to exclude transmission projects from competition for any of these exclusion categories.

153 169 FERC ¶ 61,054 (2019).
154 LSP Transmission Holdings II, LLC v. FERC, 45 F.4th 979.
155 *Id.* at 999.
156 *Id.*
157 See OA Schedule 6 § 1.5.8(n).
158 See OA Schedule 6 § 1.5.8(p).

Dominion Data Center Alley Immediate Need and Long Term Solution

Dominion presented 44 supplemental project requests to serve new data center load through the summer of 2025. PJM identified the need for additional baseline reinforcements to support the load growth. Rather than a competitive process, PJM decided to designate the upgrades as immediate need and allowed Dominion to construct these lines.[159] [160]

The 2022 RTEP Window 3 addressed long term reliability needs as well as the additional baseline reinforcements for Data Center Alley. The proposal window was open from February 24, 2023, to May 31, 2023, and received 72 submissions from 10 entities. The cost estimate for the total scope of work was $5.1 billion, $1.4 billion of which was for the necessary baseline upgrades specific to the Data Center Alley reinforcements.[161] The proposed Data Center Alley solution includes 500kV and 230kV lines extensions, the reconductoring of multiple 230kV lines and substation work.[162]

On December 8, 2023, the Maryland Office of People's Counsel (MDOPC) submitted a letter to the PJM Board.[163] The letter requested that the PJM Board defer the December 11, 2023, vote on the 2022 RTEP Window 3 proposal. The MDOPC letter cited concerns regarding the scale, scope and cost of the proposal. Additionally, the MDOPC expressed concerns that "the current failure to unpack the relative contribution of each of the "drivers" of the need for the W3 projects makes it impossible for the public to understand how cost causation principles apply to the projects." On December 11, 2023, the PJM Board approved the recommended solution. PJM filed the RTEP on January 10, 2024, and the Commission accepted it by order issued April 8, 2024.[164]

159 See "Dominion Northern Virginia Area Violations," presented at the July 12, 2022 meeting of the Transmission Expansion Advisory Committee. <https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20220712/item-08---dominion-northern-virginia-area-violations---need-statement.ashx>.
160 See "Dominion Northern Virginia Area Immediate Need," presented at the July 12, 2022 meeting of the Transmission Expansion Advisory Committee. <https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20220712/item-08---dominion-northern-virginia---immediate-need.ashx>.
161 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>.
162 See "*Reliability Analysis Report: 2022 RTEP Window 3*," December 8, 2023. <https://www.pjm.com/-/media/committees-groups/committees/teac/2023/20231205/20231205-2022-rtep-window-3-reliability-analysis-report.ashx.
163 See "MD Office of People's Counsel Letter regarding 2022 RTEP Window 3 Procurement," <https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20231208-pjm-board-letter-2023-12-08-md-opc-final.ashx>.
164 See 187 FERC ¶ 61,012. Maryland Office of the People's Counsel filed a protest, which the Commission determined was outside of the scope of the RTEP filing.

Comparative Cost Framework

The MMU recommended that rules be implemented to require that project cost caps on new transmission projects be part of the evaluation of competing projects. 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 cost framework to evaluate the quality and effectiveness of binding cost containment proposals versus proposals without cost containment provisions. On March 20, 2020, the Commission approved PJM's filing to amend the PJM Operating Agreement to incorporate this requirement.[165]

The 2020 RTEP Window 1 was the first open window that received cost capping proposals to be evaluated under the comparative cost framework. PJM has not provided the requested data to the MMU to allow for an analysis of their financial review process. Without this data and analysis, the MMU cannot verify that the analysis performed under the comparative cost framework was sufficient or adequately followed the process defined in the PJM manual.[166] The existing proposal templates do not provide enough information to adequately perform a financial analysis. 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.

Storage As A Transmission Asset (SATA)

The PJM Planning Committee considered whether storage devices should be included in the RTEP process as transmission assets.[167] On February 24, 2021, the Markets and Reliability Committee (MRC) voted to defer endorsement of governing document language associated with Storage as a Transmission Asset in reliability planning. The MRC chose to defer the language until a comprehensive proposal addressing all aspects of incorporation of storage resources into markets, operations and planning.

165 See 170 FERC ¶ 61,243 (2020).
166 See "PJM Manual 14F: Competitive Planning Process," Rev. 10 (October 30, 2024).
167 See PJM. "*Storage As A Transmission Asset: Problem / Opportunity Statement,*" <https://pjm.com/-/media/committees-groups/committees/pc/2020/20200605-special/20200605-item-02a-storage-as-a-transmission-asset-problem-statement-clean.ashx>.

Transmission and generation have, and have always had, a symbiotic relationship in the provision of wholesale power. Transmission needs generation to function and generation needs transmission to function. Transmission can substitute for generation at the margin and generation can substitute for transmission at the margin. This relationship has always been a relatively unexamined area in the design of competitive wholesale power markets. For example, there is little if any explicit consideration of the impact of transmission planning on competitive generation investment in RTO/ISO market rules. Improvement is needed in these areas. Introducing confusion about what assets are classified as generation and what assets are classified as transmission frustrates potential reform and undermines the competitive markets.

On July 22, 2020, through the supplemental planning process, American Electric Power Service Corporation (AEP) filed, on behalf of Kentucky Power Company (Kentucky Power), a Petition for Declaratory Order seeking confirmation that its Middle Creek energy storage project is eligible for cost of service recovery through AEP's formula rates.[168] AEP's Middle Creek energy storage project was a proposed battery storage device that would discharge energy to serve retail load at the Middle Creek substation in the event of a transmission outage. On December 21, 2020, the Commission ruled that the Middle Creek energy storage project did not perform a transmission function, and was ineligible to recover its costs through formula rates.[169]

Storage devices like batteries that are defined to be part of PJM markets should not be treated as transmission assets. These devices should be treated as market assets. The MMU recommends that storage resources not be includable as transmission assets for any reason.

Board Authorized Transmission Upgrades

The Transmission Expansion Advisory Committee (TEAC) regularly reviews internal and external proposals to improve transmission reliability throughout PJM. These proposals, which include reliability baseline, network, market efficiency and targeted market efficiency projects, as well as scope changes

168 See *AEP*, Docket No. EL20-58 (July 22, 2020).
169 173 FERC ¶ 61,264 (2020).

and project cancellations, but exclude supplemental and end of life projects, are periodically presented to the PJM Board of Managers for authorization.[170]

An RTEP project can be approved by the PJM Board if the project ensures compliance with NERC, regional and local transmission owner planning criteria or to address market efficiency congestion relief. These projects are considered Baseline Projects. PJM Board approved RTEP projects that are necessary to allow new generation to interconnect reliably are considered Network Projects.

In the first three months of 2026, the PJM Board approved a net change of $12.2 billion in transmission upgrades. As of March 31, 2026, the PJM Board had approved $70.8 billion in transmission system enhancements since 1999.

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.

If a QTU that was cleared in a Base Residual Auction (BRA) or Incremental Auction (IA) is not completed by the start of the Delivery Year, the submitting party is required to provide replacement 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, 2026, no QTUs have cleared a BRA or IA.

Cost Allocation

Required transmission enhancements are categorized as: supplemental, network or baseline upgrades. The cost allocation of the transmission enhancements depends on the category of upgrades.

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

Supplemental Upgrade Cost Allocation

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."[171] Supplemental projects are exempt from competition. The costs of supplemental projects are allocated 100 percent to the zone in which the transmission facilities are located.[172]

Network Upgrade Cost Allocation

Any entity that requests interconnection of a new generating facility, including increases to the capacity of an existing generating unit, or that requests interconnection of a merchant transmission facility, must follow the process defined in the PJM tariff to obtain interconnection service.[173] PJM's process is designed to ensure that new generation is added in a reliable and systematic manner. The process assigns the upgrade costs to the project or projects that are causing the costs to be incurred. As part of the interconnection planning process, a series of studies are performed to determine the feasibility, impact, and cost of interconnecting projects in the queue. The interconnection service agreement identifies the transmission modifications needed to maintain the reliability of the transmission system as a result of a new service request. These identified modifications are known as network upgrades. For required network upgrades under the new cluster based service request cycles, the costs of the network upgrades are assigned to individual projects that caused the costs to be incurred.[174]

Baseline Upgrade Cost Allocation

The PJM RTEP process is designed to identify needed transmission system additions and improvements to continue to provide reliable service throughout the RTO. Typically, load growth creates conditions that may create violations

171 See PJM. "Transmission Construction Status," (Accessed on March 31, 2026) <https://www.pjm.com/planning/m/project-construction>.
172 See OATT Schedule 12(a)(iii).
173 See OATT Parts IV & VI.
174 See "PJM Manual 14H: New Service Requests Cycle Process," Rev. 03 (September 25, 2025).

of reliability criteria, which in turn require upgrades. The PJM RTEP identifies necessary upgrades to remain compliant with national and regional reliability standards. These modifications are baseline upgrades. Baseline upgrades can also include market efficiency projects.

The costs of regional baseline facilities are allocated 50 percent on a load-ratio share and 50 percent on a directionally weighted solution based DFAX method.[175]

The costs of the necessary lower voltage facilities required to support the regional baseline facilities with estimated costs greater than or equal to $5 million are assigned on a directionally weighted solution based DFAX method.

The costs of the necessary lower voltage facilities required to support the regional baseline facilities with estimated costs below $5 million are assigned to the zone where the upgrade is located.

In response to complaints against PJM RTEP Baseline Upgrade Filings in 2014 that included cost allocations for $1.5 billion in baseline transmission enhancements and expansions, on November 24, 2015, FERC issued an order directing investigation of "whether there is a definable category of reliability projects within PJM for which the solution-based DFAX cost allocation method may not be just and reasonable, such as projects addressing reliability violations that are not related to flow on the planned transmission facility, and whether an alternative just and reasonable *ex ante* cost allocation method could be established for any such category of projects."[176] FERC convened a technical conference on January 12, 2016, to address the complaints in multiple proceedings and to address these two core issues.[177]

The issues identified in the complaints and at the technical conference included: whether the solutions based allocation method is appropriate for upgrades not related to transmission overload issues; whether the solutions based allocation method correctly identifies all the beneficiaries of the upgrades; whether it is reasonable to allocate a level of costs to a merchant transmission project that could force bankruptcy; and whether the significant shifts in allocation that result from use of the 0.01 distribution factor cutoff are appropriate.

On February 20, 2020, the Commission issued an Order denying rehearing requests.[178] The Commission found that PJM's solution based dfax method for regional cost allocation, including the 0.01 distribution cutoff factor, is just and reasonable.

On appeal, the U.S. Court of Appeals for the D.C. Circuit in 2022 found that FERC had failed to explain its distinction between the projects eligible to use the dfax method and those not eligible.[179] The Court objected that without adequate explanation: "The Bergen project 'addresses a non-flow related reliability issue,' just like the non-flow-based stability issue in Artificial Island, but FERC had treated the two projects differently."[180] The Court also rejected the 0.01 distribution cutoff factor as "absurd."[181] The Court remanded issues concerning PJM's solution based dfax method to FERC, where the matter is now pending.[182]

It is clear that the allocation issues are difficult. Nonetheless, allocation methods affect the efficiency of the markets. Allocation methods also affect the degree to which transmission upgrades required to serve data center load are allocated to other customers. The MMU recommends a comprehensive review of the ways in which the solution based dfax 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 are thoroughly reviewed.

As an example, the use of the arbitrary 0.01 distribution factor cutoff can result in large and inappropriate shifts in cost allocation. If the intent of the use of the 0.01 cutoff is to help eliminate small, arbitrary cost allocations to

175 See "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 58 (December 17, 2025) for a complete explanation of the directionally weighted solution based DFAX method.
176 153 FERC ¶ 61,245 at P 35 (2015).
177 See Docket Nos. EL15-18-000 (ConEd), EL15-67-000 (Linden), and EL15-95-000 (Artificial Island).
178 See 170 FERC ¶ 61,122 (2020).
179 See *Consolidated Edison v. FERC et al.*, 45 F.4th 265 (D.C. Cir. August 9, 2022).
180 *Id.* at 9.
181 See *id.*
182 See FERC Docket Nos. EL21-39-000, et al.

geographically distant areas, this could be achieved by adding a threshold for a minimum usage impact on the line. The MMU recommends changing the minimum distribution factor in the allocation from 0.01 to 0.00 and adding a threshold minimum impact on the load on the line based on a complete analysis of the intent of the allocation and the impacts of the allocation.

By order issued March 6, 2026, the Commission issued an order finding the distribution factor cutoff unjust and unreasonable, consistent with the MMU's recommendation on this issue.[183] The order also found that "additional record evidence is necessary to determine whether the existing rate, in which PJM uses the solution-based DFAX method to allocate either 50% or 100% of the costs of transmission projects that address short circuit reliability issues, is unjust and unreasonable."[184] The order establishes paper hearing procedures to further develop the record on this issue.[185]

Transmission Line Ratings

Transmission line ratings, and more broadly transmission facility ratings, are the metric for the ability of transmission lines to transmit power from one point to another. Transmission line ratings have significant and frequently underappreciated impacts on competitive wholesale power markets like PJM. Line ratings directly affect energy and capacity prices, the frequency and level of congestion in the day-ahead and real-time energy market, day-ahead nodal price differences and the associated value of FTRs, locational price differences in the capacity market, the need to invest in additional transmission capacity, the need to invest in additional generation capacity, the location of new power plants, and the costs for the interconnection of new power plants. The impact of transmission facility ratings on markets is a function both of the line ratings directly and the use of those ratings by the RTO/ISO.

Congestion payments by load result when lower cost generation is not available to meet all the load in an area as a result of limits on the transmission system. When higher cost local generation is needed to meet part of the local load because of transmission limits, 100 percent of the local load pays the higher price while only the local generation receives the higher price. The difference between what the load pays and generators receive is congestion. Since 2008, congestion costs in PJM have ranged from $0.5 billion to $2.05 billion per year. The fact that PJM rules continue to fail to ensure the return of 100 percent of congestion costs to the load that pays them means that higher congestion increases costs to load.

LMP may, at times, be set by transmission constraint penalty factors. When a transmission constraint is binding and there are no generation alternatives to resolve the constraint, system operators may allow the transmission limit to be violated. When this occurs, the shadow price of the constraint is set by transmission constraint penalty factors. The shadow price directly affects the LMP. Transmission constraint penalty factors were fully implemented in PJM pricing effective February 1, 2019.[186]

Transmission line ratings can result in short term, significant increases in prices as a result of the application of transmission constraint penalty factors. For example, violation of a transmission constraint, meaning that the flow exceeds the line limit, generally results in at least a $2,000 per MWh price. As the power flows approach their rated limits, PJM dispatchers often reduce the control percent on transmission limits applied in SCED by the setting the limit to an average of 95 percent of its actual limit.[187] Violation of these reduced control percent line ratings results in penalty factors setting prices in SCED.[188]

Holding aside the issues with operators reducing the control percent in SCED, the more important point is that the underlying line ratings have a significant impact on the cost of energy and capacity but have never been reviewed or standardized by ISOs/RTOs or by regulators. The line ratings issues will begin to be addressed beginning on July 12, 2025. [189]

Capacity market prices separate locally when transmission capability into Locational Deliverable Areas (LDA) is not adequate to meet the LDA capacity

183 See 194 FERC ¶ 61,179 at PP 54–63 (2026).
184 *Id.* at P 72.
185 *Id.*

186 For more information, see the *2024 Annual State of the Market Report for PJM*, Section 3: Energy Market.
187 See "Transmission Constraint Control Logic and Penalty Factors," presented at the May 10, 2018, meeting of the Markets Implementation Committee Special Session:Transmission Constraint Penalty Factors at p14. <https://www.pjm.com/-/media/committees-groups/committees/mic/20180510-special/20180510-item-03-transmission-constraint-penalty-factor-education.ashx>.
188 See the *2024 Annual State of the Market Report for PJM*, Section 3: Energy Market.
189 *Managing Transmission Line Ratings*, Order No. 881, 177 FERC ¶ 61,179 at P 39 (2021) ("Order No. 881"), *order on reh'g*, Order No. 881-A, 179 FERC ¶ 61,125 (2022) ("Order No. 881-A").

requirement with the lowest cost capacity. The available transmission capability into LDAs is defined as the Capacity Emergency Transfer Limit (CETL). Higher cost LDAs are the equivalent in the capacity market of congestion in the energy market. Load in the higher cost LDAs pay more for capacity than those in lower cost LDAs. For example, the clearing price for the BGE LDA in the 2021/2022 Base Residual Auction was $200.30 per MW-day. The clearing price for the EMAAC LDA was $165.73 per MW-day.[190]

Transmission line ratings for a given transmission facility vary by the duration of the power flow, by ambient temperatures, by wind speed and by other conditions. Transmission lines can operate with higher loads for shorter periods of time. This is significant when a contingency is expected to last for only a short period. The transmission line rating can mean the difference between substantial congestion costs and no congestion costs. The transmission line rating can mean the difference between a transmission penalty factor and no penalty factor.

In PJM, transmission owners use a range of ratings by duration.[191] PJM requires transmission owners to provide thermal ratings under normal operating conditions, long term emergency operating conditions, short term emergency operating conditions and the extreme load dump conditions. But there is no requirement that the ratings differ for these operating conditions. PJM typically uses normal line ratings for precontingency (base case) constraints and long term emergency line ratings (four hours) for contingency constraints. PJM requires transmission owners to provide temperature based line ratings separately for night and day times. The temperature ranges from 32 degree Fahrenheit or below to 95 degree Fahrenheit or above in nine degree increments. But there is no requirement that the ratings differ for these operating condition temperatures. In PJM, transmission owners are responsible for developing their own methods to compute line ratings subject to a range of NERC guidelines and requirements. PJM does not review or verify the accuracy of transmission owners' methods to compute line ratings. In PJM, transmission owners have substantial discretion in the approach to line ratings.[192]

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.

Line ratings determine the actual value of transmission in market operations. Yet the methods for defining line ratings remain opaque and vary significantly across transmission owners. Under defining line ratings results in over building transmission. Dynamic line ratings are essential to reflect the actual availability of transmission in real time as ambient conditions change. Ensuring that system operators have accurate information about line ratings, including a wide range of line ratings by duration of load, are essential to ensure that all market participants receive the maximum value from the investment in the transmission system.

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. In PJM, real-time prices are calculated every five minutes for thousands of nodes. PJM prices are extremely sensitive to transmission line ratings.

The MMU recommends that all PJM transmission owners use the same methods to define line ratings and implement dynamic line ratings (DLR), subject to NERC standards and guidelines, subject to review by NERC, PJM and the

190 See the "Analysis of the 2021/2022 RPM Base Residual Auction," <https://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).
191 See "PJM Manual 03: Transmission Operations," Rev. 70 (March 4, 2026) § 2.1.1, at p 30.
192 PJM presentation to the Planning Committee (PC) (May 3, 2018) "Transmission Owner Ratings Development and Reporting in PJM" ("There are no requirements for PJM to approve or verify a TO's ratings or do any kind of consistency check.") at 24.

MMU, and approval by FERC. The same facilities should have the same basic ratings under the same operating conditions regardless of the transmission owner. Transmission owner discretion should be minimized or eliminated. The line rating methods should be based on the basic engineering facts of the transmission system components and reflect the impact of actual operating conditions on the ratings of transmission facilities, including ambient temperatures and wind speed when relevant.[193] The line rating methods should be public and fully transparent.

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.[194] All line rating changes and the detailed reasons for those changes should be public and fully transparent.

The Commission adopted rules that enhance the ability of PJM and the MMU to understand and monitor line ratings on the PJM grid. Order No. 881, issued December 16, 2021, requires that: transmission providers implement ambient adjusted ratings on transmission lines; RTOs/ISOs implement the systems and procedures necessary for hourly ratings updates; transmission providers use uniquely determined emergency ratings; transmission owners share transmission line ratings and transmission line rating methods with RTOs/ISOs and market monitors; transmission providers maintain a database of transmission line ratings and transmission line rating methods on OASIS or other password-protected website.[195] [196]

On rehearing, the Commission provided clarification of market monitors' ability to take action based on information received about transmission line ratings: "We expect that market monitors may use the transmission line rating information available to them in furtherance of their existing responsibilities, which are set forth in the Commission's regulations and the relevant tariffs of each RTO/ISO."[197]

193 *See* "Transmission Owner Ratings Development and Reporting in PJM," presented at May 3, 2018 meeting of the Planning Committee.
194 *See* the *2024 Annual State of the Market Report for PJM*, Section 3: Energy Market.
195 *Managing Transmission Line Ratings*, Order No. 881, 177 FERC ¶ 61,179 at P 39 (2021) ("Order No. 881"), *order on reh'g*, Order No. 881-A, 179 FERC ¶ 61,125 (2022) ("Order No. 881-A").
196 *See* 18 CFR § 35.28(c)(5)&(g)(13).
197 Order No. 881-A at P 91.

Order No. 881 enhances transparency of information on line ratings and how they are determined. Requiring ambient and hourly adjustments constitutes substantive improvement. Continued reform consistent with the MMU's recommendations is needed in order to ensure consistent and accurate transmission line ratings in PJM.

By letter order issued November 22, 2023, the Commission accepted PJM's filing in compliance with Order Nos. 881 and 881-A, to be implemented no later than July 12, 2025.[198]

On February 28, 2025, PJM requested that the Commission extend PJM's deadline to comply with Order No. 881 compliance directives by nine months, (to no later than April 15, 2026).[199] The extension was requested to allow for required software development and testing. On March 31, 2025, the Commission approved the implementation extension request.[200] PJM implemented Order 881 on March 4, 2026.

Order No. 881 did not require the use of dynamic line ratings ("DLR") based on an insufficient record.[201] On June 27, 2024, the Commission issued an Advanced Notice of Proposed Rulemaking in Docket RM24-6 on the implementation of dynamic line ratings.[202]

Dynamic Line Ratings (DLR) and Grid Enhancing Technology (GETs)

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. The relevant real-time conditions include ambient air temperature, wind speeds, solar heating, transmission line tension, and transmission line sag. The widespread adoption of dynamic line ratings should be pursued. The adoption of dynamic line ratings does not require the exorbitant incentives proposed by some. Dynamic line rating technology (DLR) and other Grid Enhancing Technology (GET) should be subject to competition and the costs

198 See Docket No. ER22-2359-000. PJM must notify the Commission of the effective date no later than November 12, 2024.
199 See PJM, Docket No. ER22-2359-000. (February 28, 2025).
200 See 190 FERC ¶ 61,204 (March 31, 2025).
201 Order No. 881 at PP 25, 254.
202 See 187 FERC ¶ 61,201.

of implementation should be capped at the costs that would result from the current cost of service method applied to transmission owners. The proposal that providers of GET should receive a share of forecast benefits is not consistent with competition, would pay rates of return many multiples of market rates of return and suffers from the same intractable problem of defining speculative benefits for long periods.

As a first small step towards broader implementation of DLR by all transmission owners in PJM, PPL Electric Utilities, on its own initiative, implemented DLR for three 230 KV transmission lines in northeastern Pennsylvania on October 6, 2022, that have experienced congestion. (The two circuit Susquehanna-Harwood path and the Juniata-Cumberland line.) PPL provides streaming data from the DLR system to PJM operators.

PJM developed technical reference guides to aid in the understanding and consideration of grid enhancing technologies on the PJM system. The technical reference guides provide additional information on dynamic line ratings, advanced power flow controllers, topology control and optimization and advanced conductors.[203]

Transmission Facility Outages

Scheduling Transmission Facility Outage Requests

A transmission facility is designated as reportable by PJM if a change in its status can affect a transmission constraint on any Monitored Transmission Facility or could impede free flowing ties within the PJM RTO and/or adjacent areas.[204] When a reportable transmission facility needs to be taken out of service, the transmission owner is required to submit an outage request as early as possible.[205] The specific timeline is shown in Table 12-85.[206]

Transmission outages have significant impacts on PJM markets, including impacts on FTR auctions, on congestion, and on expected market outcomes in the day-ahead and real-time markets. The efficient functioning of the markets depends on clear, enforceable rules governing transmission outages.

The outage data for the FTR market are for outages scheduled to occur in the 2024/2025 planning period and the first 10 months of the 2025/2026 planning period, regardless of when they were initially submitted.[207] The outage data for the day-ahead market are for outages scheduled to occur from January 2015 through March 2026.

Transmission outages are categorized by duration: greater than 30 calendar days; less than or equal to 30 calendar days; greater than five calendar days; less than or equal to five calendar days.[208] Table 12-84 shows that 74.6 percent of requested outages were planned for less than or equal to five days and 10.1 percent of requested outages were planned for greater than 30 days in the first 10 months of the 2025/2026 planning period. Table 12-84 also shows that 75.2 percent of the requested outages were planned for less than or equal to five days and 9.2 percent of requested outages were planned for greater than 30 days in the 2024/2025 planning period.

Table 12-84 Transmission facility outage request summary by planned duration: June 2024 through March 2026

	2024/2025 (12 months)		2025/2026 (10 months)	
Planned Duration (Days)	Outage Requests	Percent of Total	Outage Requests	Percent of Total
<=5	15,091	75.2%	13,130	74.6%
>5 & <=30	3,148	15.7%	2,666	15.2%
>30	1,842	9.2%	1,797	10.2%
Total	20,081	100.0%	17,593	100.0%

After receiving a transmission facility outage request from a TO, PJM assigns a received status to the request based on its submission date and outage planned duration. The received status can be On Time or Late, as defined in Table 12-85.[209]

203 See PJM. About PJM "Grid Optimization Solutions," <https://www.pjm.com/markets-and-operations/grid-optimization-solutions>.
204 If a transmission facility is not modeled in the PJM EMS or the facility is not expected to significantly impact PJM system security or congestion management, it is not reportable. See PJM, "Manual 3: Transmission Operations," Rev. 70 (Mar. 4, 2026).
205 See PJM, "Manual 3: Transmission Operations," Rev. 70 (Mar. 4, 2026).
206 See PJM, "Manual 3: Transmission Operations," Rev. 70 (Mar. 4, 2026).
207 The hotline tickets, EMS tripping tickets or test outage tickets were excluded. The analysis includes only the transmission outage tickets submitted by PJM companies which are currently active.
208 *Id.* at 70.
209 See PJM, "Manual 3: Transmission Operations," Rev. 70 (Mar. 4, 2026).

The purpose of the rules defined in Table 12-85 is to require the TOs to submit transmission facility outages prior to the Financial Transmission Right (FTR) auctions so that market participants have complete information about market conditions on which to base their FTR bids and PJM can accurately model market conditions.[210]

Table 12-85 Transmission facility outage request received status definition

Planned Duration (Calendar Days)	Request Submitted	Received Status
<=5	Before the first of the month one month prior to the starting month of the outage	On Time
	After or on the first of the month one month prior to the starting month of the outage	Late
> 5 & <=30	Before the first of the month six months prior to the starting month of the outage	On Time
	After or on the first of the month six months prior to the starting month of the outage	Late
>30	Before the earlier of 1) February 1, 2) the first of the month six months prior to the starting month of the outage	On Time
	After or on the earlier of 1) February 1, 2) the first of the month six months prior to the starting month of the outage	Late

Table 12-86 shows a summary of requests by received status. In the first 10 months of the 2025/2026 planning period, 41.8 percent of outage requests received were late. In the 2024/2025 planning period, 40.5 percent of outage requests received were late.

Table 12-86 Transmission facility outage requests by received status: June 2024 through March 2026

	2024/2025 (12 months)				2025/2026 (10 months)			
Planned Duration (Days)	On Time	Late	Total	Percent Late	On Time	Late	Total	Percent Late
<=5	9,556	5,535	15,091	36.7%	8,126	5,004	13,130	38.1%
>5 & <=30	1,684	1,464	3,148	46.5%	1,419	1,247	2,666	46.8%
>30	705	1,137	1,842	61.7%	690	1,107	1,797	61.6%
Total	11,945	8,136	20,081	40.5%	10,235	7,358	17,593	41.8%

Once received, PJM processes outage requests in priority order: emergency transmission outage request; transmission outage request submitted on time; and transmission outage request submitted late. Transmission outage requests that are submitted late may be approved if the outage does not affect the reliability of PJM or cause congestion in the system.[211]

Outages with emergency status will be approved even if submitted late after PJM determines that the outage does not result in Emergency Procedures. PJM cancels or withholds approval of any outage that results in Emergency Procedures.[212] Table 12-87 is a summary of outage requests by emergency status. Of all outage requests scheduled to occur in the first 10 months of the 2025/2026 planning period, 13.1 percent were for emergency outages. Of all outage requests scheduled to occur in the 2024/2025 planning period, 12.1 percent were for emergency outages.

Table 12-87 Transmission facility outage requests by emergency: June 2024 through March 2026

	2024/2025 (12 months)				2025/2026 (10 months)			
Planned Duration (Days)	Emergency	Non Emergency	Total	Percent Emergency	Emergency	Non Emergency	Total	Percent Emergency
<=5	1,709	13,382	15,091	11.3%	1,667	11,463	13,130	12.7%
>5 & <=30	400	2,748	3,148	12.7%	333	2,333	2,666	12.5%
>30	325	1,517	1,842	17.6%	304	1,493	1,797	16.9%
Total	2,434	17,647	20,081	12.1%	2,304	15,289	17,593	13.1%

PJM will approve all transmission outage requests that are submitted on time and do not jeopardize the reliability of the PJM system. PJM will approve all transmission outage requests that are submitted late and are not expected to cause congestion on the PJM system and do not jeopardize the reliability of the PJM system. Each outage is studied and if it is expected to cause a constraint to exceed a limit, PJM will flag the outage ticket as "congestion expected."[213]

After PJM determines that a late request may cause congestion, PJM informs the transmission owner of solutions available to eliminate the congestion. For

210 See "Report of PJM Interconnection, L.L.C. on Transmission Oversight Procedures," Docket No. EL01-122-000 (November 2, 2001).

211 See PJM, "Manual 3: Transmission Operations," Rev. 70 (Mar. 4, 2026). The following language was removed from Manual 3 Rev. 50: PJM retains the right to deny all jobs submitted after 8 a.m. three days prior to the requested start date unless the request is an emergency job or an exception request (i.e. a generator tripped and the Transmission Owner is taking advantage of a situation that was not available before the unit trip).

212 PJM, "Manual 3: Transmission Operations," Rev. 70 (Mar. 4, 2026).

213 PJM added this definition to Manual 38 in February 2017. PJM, "Manual 38: Operations Planning," Rev. 20 (Jan. 22, 2026).

example, if a generator planned or maintenance outage request is contributing to the congestion, PJM can request that the generation owner defer the outage. If no solutions are available, PJM may require the transmission owner to reschedule or cancel the outage.

Table 12-88 is a summary of outage requests by congestion status. Of all outage requests submitted to occur in the first 10 months of the 2025/2026 planning period, 9.7 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 5.2 percent (88 out of 1,702) were denied by PJM in the first 10 months of the 2025/2026 planning period and 16.5 percent (242 out of 1,467) were cancelled (Table 12-90). Of all outage requests submitted to occur in the 2024/2025 planning period, 9.1 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 5.2 percent (94 out of 1,818) were denied by PJM in the 2024/2025 planning period and 20.5 percent (373 out of 1,818) were cancelled (Table 12-90).

Table 12-88 Transmission facility outage requests by congestion: June 2024 through March 2026

	2024/2025 (12 months)				2025/2026 (10 months)			
Planned Duration (Days)	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected
<=5	1,242	13,849	15,091	8.2%	1,131	11,999	13,130	8.6%
>5 & <=30	388	2,760	3,148	12.3%	361	2,305	2,666	13.5%
>30	188	1,654	1,842	10.2%	211	1,586	1,797	11.7%
Total	1,818	18,263	20,081	9.1%	1,703	15,890	17,593	9.7%

Table 12-89 shows the outage requests summary by received status, congestion status and emergency status. In the first 10 months of the 2025/2026 planning period, 29.0 percent of requests were submitted late and were nonemergency while 1.7 percent of requests (302 out of 17,593) were late, nonemergency, and expected to cause congestion. In the 2024/2025 planning period, 28.5 percent of requests were submitted late and were nonemergency while 1.6 percent of requests (325 out of 20,081) were late, nonemergency, and expected to cause congestion.

Table 12-89 Transmission facility outage requests by received status, emergency and congestion: June 2024 through March 2026

		2024/2025 (12 months)				2025/2026 (10 months)			
Received Status		Congestion Expected	No Congestion Expected	Total	Percent of Total	Congestion Expected	No Congestion Expected	Total	Percent of Total
Late	Emergency	121	2,286	2,407	12.0%	118	2,144	2,262	12.9%
	Non Emergency	325	5,404	5,729	28.5%	302	4,794	5,096	29.0%
On Time	Emergency	2	25	27	0.1%	8	34	42	0.2%
	Non Emergency	1,370	10,548	11,918	59.3%	1,275	8,918	10,193	57.9%
Total		1,818	18,263	20,081	100.0%	1,703	15,890	17,593	100.0%

Once PJM processes an outage request, the outage request is labelled as Submitted, Received, Denied, Approved, Cancelled by Company, PJM Admin Closure, Revised, Active or Complete according to the processed stage of a request.[214] Table 12-90 shows the detailed process status for outage requests only for the outage requests that are expected to cause congestion. Status Submitted and status Received are in the In Process category and status Cancelled by Company and status PJM Admin Closure are in the Cancelled category in Table 12-90. Table 12-90 shows that of all the outage requests that were expected to cause congestion, 5.2 percent (88 out of 1,702) were denied by PJM in the first 10 months of the 2025/2026 planning period, 64.7 percent were complete and 20.0 percent (340 out of 1,702) were cancelled. Of all the outage requests that were expected to cause congestion, 5.2 percent (94 out of 1,818) were denied by PJM in the 2024/2025 planning period, 67.5 percent were complete and 20.5 percent (373 out of 1,818) were cancelled.

214 See PJM Markets & Operations, PJM Tools "Outage Information," <http://www.pjm.com/markets-and-operations/etools/oasis/system-information/outage-info.aspx> (2019).

Table 12-90 Transmission facility outage requests by processed status[215]:June 2024 through March 2026

		2024/2025 (12 months)						2025/2026 (10 months)					
Received Status		Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete	Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete
Late	Emergency	12	104	3	1	121	86.0%	8	104	4	2	118	88.1%
	Non Emergency	63	222	9	28	325	68.3%	57	197	14	25	302	65.2%
On Time	Emergency	1	1	0	0	2	50.0%	1	5	2	0	8	62.5%
	Non Emergency	297	902	94	65	1,370	65.8%	274	804	120	61	1,275	63.1%
Total		373	1,229	106	94	1,818	67.6%	340	1,110	140	88	1,703	65.2%

There are clear rules defined for assigning On Time or Late status for submitted outage requests in both the PJM tariff and PJM manuals.[216] The On Time or Late status affects the way in which PJM addresses the potential to exceed transmission limits. Table 12-90 shows that in the first 10 months of the 2025/2026 planning period, 302 nonemergency outage requests were submitted late and expected to cause congestion. The expected impact on congestion and the options for controlling that congestion is the basis for PJM's treatment of late outage requests.

The definition of this congestion analysis in the PJM manuals is about physical limits and not about economic congestion. PJM approves on time outages based solely on whether limits are exceeded and available controlling actions, without regard to the resulting level of economic congestion. The MMU recommends that PJM draft a definition of the 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.[217]

215 The number of denied transmission outage requests is lower than calculated by PJM the MMU includes only the transmission outage requests with "Denied" as a final status, while PJM included both transmission outage requests with "Denied" as a final status and transmission outage requests with "Denied" as an intermediate status.
216 OA Schedule 1 § 1.9.2.
217 "PJM Manual 38: Operations Planning," Rev. 20 (Jan. 22, 2026).. p 21. Manual 38 states: "The outages are analyzed for reliability and expected off-costs. Each outage is studied and any constraints (actual or facility/contingency pair) trending toward a limit or exceeding a limit is noted in eDART. The trending or exceeding of a limit in the study is referred to as potential "congestion". The limit may be any or a combination of thermal, voltage, or stability issues. If there is an expected constraint, PJM will mark the corresponding eDART ticket as "congestion expected". The "congestion expected" flag is used to indicate a potential issue that may occur in the Day-Ahead Market or in Real-time Operations. If there are non-cost controlling actions, changes to the generation pattern, or changes to system conditions, the noted congestion may not occur in the Day-Ahead Market or in Real-time Operations. For "On-time" outages, PJM ensures the constraint can be mitigated by applying both non-cost and off-cost operations. If there are no limit exceedances as a result, the outage will be approved. For "Late" outages, PJM will apply only non-cost operations."

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. It is not clear that PJM's analysis of expected congestion identified or highlighted the magnitude of the economic impact. Dominion Virginia Power did not stage the outage so as to minimize market disruption and congestion. After high congestion costs of Greys Point - Harmony Village constraint and market participant manipulative behavior caused by the outage were identified by the end of January, on February 11, 2022 Dominion decided to temporarily terminate the outage in March in order to work on upgrading Greys Point, Harmony Village and White Stone path. The Greys Point - Harmony Village Line has not been binding since March 14, 2022. It indicates that if the market impact of the outage was identified during PJM outage analysis process and action was taken because of the analysis result, the high congestion costs and manipulative behavior could have been prevented.

Rescheduling Transmission Facility Outage Requests

A TO can reschedule or cancel an outage after initial submission. Table 12-91 is a summary of all the outage requests planned for the 2024/2025 planning period and the first 10 months of the 2025/2026 planning period which were approved and then cancelled or rescheduled by TOs at least once. If an outage request was submitted, approved and subsequently rescheduled at least once, the outage request will be counted as Approved and Rescheduled. If an outage request was submitted, approved and subsequently cancelled at least once, the outage request will be counted as Approved and Cancelled. In the first 10 months of the 2025/2026 planning period, 26.6 percent of transmission outage requests were approved by PJM and then rescheduled by the TOs, and 10.1 percent of the transmission outages were approved by PJM and subsequently cancelled by the TOs. In the 2024/2025 planning period, 30.1 percent of transmission outage requests were approved by PJM and then rescheduled by the TOs, and 12.5 percent of the transmission outages were approved by PJM and subsequently cancelled by the TOs.[218]

Table 12-91 Rescheduled and cancelled transmission outage requests: June 2024 through March 2026

	2024/2025 (12 months)					2025/2026 (10 months)				
Planned Duration (Days)	Outage Requests	Approved and Rescheduled	Percent Approved and Rescheduled	Approved and Cancelled	Percent Approved and Cancelled	Outage Requests	Approved and Rescheduled	Percent Approved and Rescheduled	Approved and Cancelled	Percent Approved and Cancelled
<=5	15,091	3,071	20.3%	2,154	14.3%	13,130	2,428	18.5%	1,520	11.6%
>5 & <=30	3,148	1,809	57.5%	260	8.3%	2,666	1,286	48.2%	183	6.9%
>30	1,842	1,212	65.8%	96	5.2%	1,797	985	54.8%	80	4.5%
Total	20,081	6,092	30.3%	2,510	12.5%	17,593	4,699	26.7%	1,783	10.1%

If a requested outage is determined to be late and TO reschedules the outage, the outage will be revaluated by PJM again as On Time or Late.

A transmission outage ticket with duration of five days or less with an On Time status can retain its On Time status if the outage is rescheduled within the original scheduled month.[219] This rule allows a TO to reschedule within the same month with very little notice.

A transmission outage ticket with a duration exceeding five days with an On Time status can retain its On Time status if the outage is rescheduled to a future month, and the revision is submitted by the first of the month prior to the revised month in which the outage will occur.[220] This rescheduling rule is much less strict than the rule that applies to the first submission of outage requests with similar duration. When first submitted, the outage request with a duration exceeding five days needs to be submitted before the first of the month six months prior to the month in which the outage was expected to occur. The rescheduling rule allows TOs to avoid the timing requirements associated with outages exceeding five days.

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.

Long Duration Transmission Facility Outage Requests

PJM rules (Table 12-85) define a transmission outage request as On Time or Late based on the planned outage duration and the time of submission. The rule has stricter submission requirements for transmission outage requests planned for longer than 30 days. In order to avoid the stricter submission requirement, some transmission owners divided the duration of outage requests longer than 30 days into shorter segments for the same equipment and submitted one request for each segment. The MMU recommends that PJM not permit

218 The number of tickets in each category can change over time. For example, a ticket initially classified as canceled or denied may be resubmitted at a later date for a different date range. Once approved the resubmitted ticket overrides the original ticket dates and details.
219 PJM, "Manual 3: Transmission Operations," Rev. 70 (Mar. 4, 2026).
220 *Id.*

transmission owners to divide long duration outages into smaller segments to avoid complying with the requirements for long duration outages.

More than one outage request can be submitted for the same transmission equipment. In order to accurately present the results, Table 12-92 shows equipment outages by the equipment instead of by outage request.

Table 12-92 shows that there were 11,630 transmission equipment planned outages in the first 10 months of the 2025/2026 planning period, of which 1,542 or 13.3 percent were longer than 30 days, and of which 199 or 1.7 percent were scheduled longer than 30 days when the duration of all the outage requests are combined for the same equipment.

Table 12-92 Transmission equipment outages: June 2024 through March 2026

		2024/2025 (12 months)		2025/2026 (10 months)	
Planned Duration (Days)	Divided into Shorter Periods	Count of Equipment with Planned Outages	Percent of Total	Count of Equipment with Planned Outages	Percent of Total
> 30	No	1,588	12.3%	1,552	13.3%
	Yes	251	1.9%	196	1.7%
<= 30		11,043	85.7%	9,882	85.0%
Total		12,882	100.0%	11,630	100.0%

Table 12-93 shows the details of long duration (> 30 days) outages when combining the duration of the outage requests for the same equipment.[221] The actual duration of scheduled outages would be longer than 30 days if the duration of the outage requests was appropriately combined for the same equipment. An effective duration was calculated for each piece of equipment by subtracting the start date of the earliest outage request from the end date of the latest outage request of the equipment. In the first 10 months of the 2025/2026 planning period, with an effective duration greater than a month and shorter than two months, there were 32 outages with a combined duration longer than 30 days.[222]

221 A transmission facility is modeled as equipment in the EMS model. Equipment has three identifiers: location (B1), voltage level (B2) and equipment name (B3). The types of equipment include, for example, lines, transformers, and capacitors. There can be multiple outage requests associated with the same equipment.

222 The length of a planned equipment outage can be modified by editing an existing ticket for the equipment outage or by adding new equipment outage tickets for the same equipment.

Table 12-93 Transmission equipment outages by effective duration: June 2024 through March 2026

	2024/2025 (12 months)		2025/2026 (10 months)	
Effective Duration of Outage	Count of Equipment with Planned Outages	Percent of Total	Count of Equipment with Planned Outages	Percent of Total
<=31	9	3.6%	4	2.0%
>31 & <=62	33	13.1%	31	15.8%
>62 & <=93	18	7.2%	32	16.3%
>93	191	76.1%	129	65.8%
Total	251	100.0%	196	100.0%

Transmission Facility Outage Analysis for the FTR Market

Transmission facility outages affect the price and quantity outcomes of FTR Auctions. The purpose of the rules governing outage reporting is to ensure that outages are known with enough lead time prior to FTR Auctions so that market participants can understand market conditions and PJM can accurately model market conditions.

There are Long Term, Annual and Monthly Balance of Planning Period auctions in the FTR Market. For each type of auction, PJM includes a set of outages to be modeled.

Annual FTR Market

The Annual FTR Market includes the Annual ARR Allocation and the Annual FTR Auction. When determining transmission outages to be modeled in the simultaneous feasibility test used in the Annual FTR Market, PJM considers all outages with planned duration longer than or equal to two weeks as an initial list. Then PJM may exercise significant discretion in selecting outages to be modeled in the final model. PJM posts the final FTR outage list to the FTR web page usually at least one week before the auction bidding opening day.[223]

In the first 10 months of the 2025/2026 planning period, 166 outage requests were included in the annual FTR market outage list and 11,972 outage requests

223 PJM Financial Transmission Rights, "Annual ARR Allocation and FTR Auction Transmission Outage Modeling," <https://www.pjm.com/-/media/markets-ops/ftr/annual-ftr-auction/2018-2019/2018-2019-annual-outage-modeling.ashx?la=en> (April 5, 2018). There is no documentation on the deadline for when modeling outages should be posted on the PJM website.

were not included.[224] In the 2024/2025 planning period, 436 outage requests were included in the annual FTR market outage list and 19,644 outage requests were not included. Table 12-94, Table 12-95, Table 12-96 and Table 12-97 show the summary information on the modeled outage requests and Table 12-98 and Table 12-99 show the summary information on outages that were not included in the Annual FTR Market.

Table 12-94 shows that 14.9 percent of the outage requests modeled in the Annual FTR Market for the first 10 months of the 2025/2026 planning period had a planned duration of less than two weeks and that 14.9 percent of the outage requests (30 out of 201) modeled in the Annual FTR Market for the planning period were submitted late according to outage submission rules. It also shows that 23.2 percent of the outage requests modeled in the Annual FTR Market for the 2024/2025 planning period had a planned duration of less than two weeks and that 17.9 percent of the outage requests (78 out of 436) modeled in the Annual FTR Market for the planning period were submitted late according to outage submission rules.

Table 12-94 Annual FTR market modeled transmission facility outage requests by received status: June 2024 through March 2026

	2024/2025 (12 months)				2025/2026 (10 months)			
Planned Duration	On Time	Late	Total	Percent of Total	On Time	Late	Total	Percent of Total
<2 weeks	93	8	101	23.2%	24	8	32	15.8%
>=2 weeks & <2 months	142	20	162	37.2%	45	2	47	23.2%
>=2 months	123	50	173	39.7%	96	28	124	61.1%
Total	358	78	436	100.0%	165	38	203	100.0%

Table 12-95 shows the annual FTR market modeled outage requests summary by emergency status and received status. Two of the annual FTR market modeled outages expected to occur in the first 10 months of the 2025/2026 planning period were emergency outages. Three of the modeled outages expected to occur in the 2024/2025 planning period were emergency outages.

Table 12-95 Annual FTR market modeled transmission facility outage requests by emergency: June 2024 through March 2026

		2024/2025 (12 months)				2025/2026 (10 months)			
Received Status	Planned Duration	Emergency	Non Emergency	Total	Percent Non Emergency	Emergency	Non Emergency	Total	Percent Non Emergency
On Time	<2 weeks	0	93	93	100.0%	0	24	24	100.0%
	>=2 weeks & <2 months	1	141	142	99.3%	0	45	45	100.0%
	>=2 months	0	123	123	100.0%	0	96	96	100.0%
	Total	1	357	358	99.7%	0	165	165	100.0%
Late	<2 weeks	0	8	8	100.0%	0	8	8	100.0%
	>=2 weeks & <2 months	0	20	20	100.0%	0	2	2	100.0%
	>=2 months	3	47	50	94.0%	2	26	28	92.9%
	Total	3	75	78	96.2%	2	36	38	94.7%

PJM determines expected congestion for both On Time and Late outage requests. A Late outage request may be denied or cancelled if it is expected to cause congestion. Table 12-96 shows a summary of requests by expected congestion and received status. Of all the annual FTR market modeled outages expected to occur in the first 10 months of the 2025/2026 planning period and submitted late, 15.8 percent (6 out of 38) were expected to cause congestion. Of all the annual FTR market modeled outages expected to occur in the 2024/2025 planning period and submitted late, 20.5 percent (16 out of 78) were expected to cause congestion.

Table 12-96 Annual FTR market modeled transmission facility outage requests by congestion: June 2024 through March 2026

		2024/2025 (12 months)				2025/2026 (10 months)			
Received Status	Planned Duration	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected
On Time	<2 weeks	23	70	93	24.7%	7	17	24	29.2%
	>=2 weeks & <2 months	33	109	142	23.2%	25	20	45	55.6%
	>=2 months	32	91	123	26.0%	24	72	96	25.0%
	Total	88	270	358	24.6%	56	109	165	33.9%
Late	<2 weeks	2	6	8	25.0%	1	7	8	12.5%
	>=2 weeks & <2 months	4	16	20	20.0%	0	2	2	0.0%
	>=2 months	10	40	50	20.0%	5	23	28	17.9%
	Total	16	62	78	20.5%	6	32	38	15.8%

224 PJM's treatment of transmission outages in the FTR models is discussed in the *2024 Quarterly State of the Market Report for PJM: January through June,* Section 13: FTRs and ARRs, Supply and Demand.

Table 12-97 shows that 14.9 percent of outage requests modeled in the annual FTR market for the first 10 months of the 2025/2026 planning period and with a duration of two weeks or longer but shorter than two months were cancelled after the FTR auction was open, compared to 24.1 percent for the 2024/2025 planning period. Table 12-97 also shows that 13.7 percent of outages requests modeled in the Annual FTR Market for the first 10 months of the 2025/2026 planning period and with a duration of two months or longer were cancelled, compared to 19.1 percent for the 2024/2025 planning period.

Table 12-97 Annual FTR market modeled transmission facility outage requests by processed status: June 2024 through March 2026

		2024/2025 (12 months)		2025/2026 (10 months)	
Planned Duration	Processed Status	Outage Requests	Percent	Outage Requests	Percent
<2 weeks	In Progress	8	7.9%	3	9.4%
	Denied	1	1.0%	0	0.0%
	Approved	0	0.0%	1	3.1%
	Cancelled	28	27.7%	10	31.3%
	Revised	1	1.0%	0	0.0%
	Active	0	0.0%	0	0.0%
	Completed	63	62.4%	18	56.3%
	Total	101	100.0%	32	100.0%
>=2 weeks & <2 months	In Progress	25	15.4%	9	19.1%
	Denied	0	0.0%	1	2.1%
	Approved	2	1.2%	0	0.0%
	Cancelled	39	24.1%	7	14.9%
	Revised	0	0.0%	0	0.0%
	Active	0	0.0%	0	0.0%
	Completed	96	59.3%	30	63.8%
	Total	162	100.0%	47	100.0%
>=2 months	In Progress	24	13.9%	30	24.2%
	Denied	1	0.6%	2	1.6%
	Approved	1	0.6%	0	0.0%
	Cancelled	33	19.1%	17	13.7%
	Revised	0	0.0%	0	0.0%
	Active	8	4.6%	29	23.4%
	Completed	106	61.3%	46	37.1%
	Total	173	100.0%	124	100.0%
Total Cancelled		100	22.9%	34	16.7%
Grand Total		436		203	

More outage requests were not modeled in the Annual FTR Market than were modeled in the Annual FTR Market. In the first 10 months of the 2025/2026 planning period, 201 outage requests were modeled and 17,392 outage requests were not modeled in the Annual FTR Market. In the 2024/2025 planning period, 436 outage requests were modeled and 19,640 outage requests were not modeled in the Annual FTR Market.

Table 12-98 shows that 16.2 percent of outage requests not modeled in the Annual FTR Auction with duration longer than or equal to two months, labeled On Time according to the rules, were submitted or rescheduled after the Annual FTR Auction bidding opening date in the first 10 months of the 2025/2026 planning period, compared to 20.3 percent in the 2024/2025 planning period.

Table 12-98 Transmission facility outage requests not modeled in Annual FTR Auction: June 2024 through March 2026

	2024/2025 (12 months)						2025/2026 (10 months)					
	On Time			Late			On Time			Late		
Planned Duration	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After
<2 weeks	1,812	8,473	82.4%	202	6,163	96.8%	1,821	6,947	79.2%	562	5,167	90.2%
>=2 weeks & <2 months	663	399	37.6%	163	862	84.1%	777	232	23.0%	199	677	77.3%
>=2 months	188	52	21.7%	252	416	62.3%	243	50	17.1%	362	353	49.4%
Total	2,663	8,924	77.0%	617	7,441	92.3%	2,841	7,229	71.8%	1,123	6,197	84.7%

Table 12-99 shows that 91.2 percent of late outage requests that were submitted after the Annual FTR Auction bidding opening date, were not modeled in the Annual FTR Auction, and had a duration longer than or equal to two months, were completed in the first 10 months of the 2025/2026 planning period. It also shows that 90.6 percent of late outage requests which were not modeled in the Annual FTR Auction with duration longer than or equal to two months and submitted after the Annual FTR Auction bidding opening date were active or completed in the 2024/2025 planning period.

Table 12-99 Late transmission facility outage requests: June 2024 through March 2026

	2024/2025 (12 months)			2025/2026 (10 months)		
Planned Duration	Completed Outages	Total	Percent Complete	Completed Outages	Total	Percent Complete
<2 weeks	5,210	6,163	84.5%	4,361	5,167	84.4%
>=2 weeks & <2 months	725	862	84.1%	571	677	84.3%
>=2 months	377	416	90.6%	322	353	91.2%
Total	6,312	7,441	84.8%	5,254	6,197	84.8%

Although the definition of late outages was developed in order to prevent outages for the planning period being submitted after the opening of bidding in the Annual FTR Auction, the rules have not functioned effectively because the rule has no direct connection to the date on which bidding opens for the Annual FTR Auction. By requiring all long-duration transmission outages to be submitted before February 1, PJM outage submission rules only prevent long-duration transmission outages from being submitted late. The rule does not address the situation in which long-duration transmission outages are submitted on time, but are rescheduled so that they are late. There is no rule to address the situation in which short-duration outages (duration <= 5 days) are submitted on time, but are changed to long-duration transmission outages after the outages are approved and active. The Annual FTR Auction model may consider transmission outages planned for longer than two weeks but less than two months. Those outages not only include long duration outages but also include outages shorter than 30 days. In those cases, PJM outage submission rules failed to prevent those transmission outages from being submitted late. 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 opening date, based on those options.

Monthly FTR Market

When determining transmission outages to be modeled in the Monthly Balance of Planning Period FTR Auction, PJM considers all outages with planned duration longer than five days and may consider outages with planned durations less than or equal to five days. PJM exercises significant discretion in selecting outages to be modeled. PJM posts an FTR outage list to the FTR webpage usually at least one week before the auction bidding opening day.[225] Table 12-100 and Table 12-101 show the summary information on outage requests modeled in the Monthly Balance of Planning Period FTR Auction and Table 12-102 and Table 12-103 show the summary information on outage requests not modeled in the Monthly Balance of Planning Period FTR Auction.

225 PJM Financial Transmission Rights, "2015/2016 Monthly FTR Auction Transmission Outage Modeling," <http://www.pjm.com/-/media/markets-ops/ftr/ftr-allocation/monthly-ftr-auctions/2015-2016-monthly-transmission-outages-that-may-cause-infeasibilities.ashx?la=en> (December 9, 2015).

Table 12-100 shows that on average, 28.4 percent of the outage requests modeled in the Monthly Balance of Planning Period FTR Auction were submitted late according to outage submission rules in the first 10 months of the 2025/2026 planning period. On average, 28.8 percent of the outage requests modeled in the Monthly Balance of Planning Period FTR Auction were submitted late according to outage submission rules in the 2024/2025 planning period.

Table 12-100 Monthly Balance of Planning Period FTR Auction modeled transmission facility outage requests by received status: June 2024 through March 2026

			2024/2025				2025/2026	
				Percent				Percent
Month	On Time	Late	Total	Late	On Time	Late	Total	Late
Jun	272	134	406	33.0%	296	126	422	29.9%
Jul	154	100	254	39.4%	183	116	299	38.8%
Aug	211	101	312	32.4%	201	107	308	34.7%
Sep	488	175	663	26.4%	527	151	678	22.3%
Oct	542	190	732	26.0%	673	198	871	22.7%
Nov	511	197	708	27.8%	515	188	703	26.7%
Dec	359	127	486	26.1%	445	158	603	26.2%
Jan	239	80	319	25.1%	252	99	351	28.2%
Feb	275	103	378	27.2%	315	126	441	28.6%
Mar	477	158	635	24.9%	527	183	710	25.8%
Apr	515	192	707	27.2%				
May	482	203	685	29.6%				
Average	377	147	524	28.8%	406	149	539	28.4%

Table 12-101 shows that on average, 17.6 percent of outage requests modeled in the Monthly Balance of Planning Period FTR Auction were cancelled in the first 10 months of the 2025/2026 planning period. On average, 20.1 percent of outage requests modeled in the Monthly Balance of Planning Period FTR Auction were cancelled in the 2024/2025 planning period.

Table 12-101 Monthly Balance of Planning Period FTR Auction modeled transmission facility outage requests by processed status: June 2024 through March 2026

Planning Year	Month	In Process	Denied	Approved	Cancelled	Revised	Active	Complete	Total	Percent Cancelled
2024/2025	Jun	28	13	16	93	0	90	166	406	22.9%
	Jul	22	8	15	41	0	97	71	254	16.1%
	Aug	18	16	10	68	0	81	119	312	21.8%
	Sep	70	7	30	111	0	192	253	663	16.7%
	Oct	60	1	19	174	2	209	267	732	23.8%
	Nov	63	5	23	124	0	185	308	708	17.5%
	Dec	40	16	8	101	0	101	220	486	20.8%
	Jan	41	9	9	67	0	110	83	319	21.0%
	Feb	27	6	11	79	0	116	139	378	20.9%
	Mar	62	5	19	139	1	164	245	635	21.9%
	Apr	61	6	18	133	0	200	289	707	18.8%
	May	43	11	17	135	1	123	355	685	19.7%
	Average	45	9	16	105	0	139	210	524	20.1%
2025/2026	Jun	50	20	15	72	0	91	174	422	17.1%
	Jul	29	17	10	52	0	97	94	299	17.4%
	Aug	39	9	8	49	0	84	119	308	15.9%
	Sep	73	6	25	128	1	204	241	678	18.9%
	Oct	91	3	32	177	1	233	334	871	20.3%
	Nov	59	10	16	126	0	186	306	703	17.9%
	Dec	58	15	8	128	0	99	295	603	21.2%
	Jan	57	34	14	57	4	85	100	351	16.2%
	Feb	85	2	21	65	0	125	143	441	14.7%
	Mar	82	7	31	155	0	183	252	710	21.8%
	Average	48	13	15	75	0	119	157	427	17.6%

Table 12-102 shows that on average, 12.0 percent of outage requests not modeled in the Monthly Balance of Planning Period FTR Auction, labeled On Time according to the rules, were submitted after the monthly FTR auction bidding opening dates in the first 10 months of the 2025/2026 planning period, compared to 14.0 percent in the 2024/2025 planning period. On average, 54.4 percent of outage requests not modeled in the Monthly Balance of Planning Period FTR Auction, labeled Late according to the rules, were submitted after the Monthly Balance of Planning Period FTR Auction bidding opening dates in the first 10 months of the 2025/2026 planning period, compared to 57.2 percent in the 2024/2025 planning period.

Table 12-102 Transmission facility outage requests not modeled in Monthly Balance of Planning Period FTR Auction: June 2024 through March 2026

	2024/2025						2025/2026					
	On Time			Late			On Time			Late		
	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After
Jun	683	152	18.2%	376	566	60.1%	695	148	17.6%	424	732	63.3%
Jul	438	152	25.8%	304	541	64.0%	455	136	23.0%	341	655	65.8%
Aug	453	107	19.1%	296	482	62.0%	440	105	19.3%	349	631	64.4%
Sep	981	107	9.8%	335	530	61.3%	1,040	95	8.4%	402	600	59.9%
Oct	1,113	131	10.5%	412	733	64.0%	1,100	81	6.9%	435	735	62.8%
Nov	717	81	10.2%	443	530	54.5%	823	88	9.7%	491	609	55.4%
Dec	597	122	17.0%	428	487	53.2%	685	86	11.2%	419	554	56.9%
Jan	484	138	22.2%	368	546	59.7%	1,368	156	10.2%	1,222	566	31.7%
Feb	625	102	14.0%	410	530	56.4%	764	122	13.8%	405	721	64.0%
Mar	1,217	144	10.6%	433	785	64.4%	1,645	10	0.6%	952	255	21.1%
Apr	1,307	146	10.0%	504	696	58.0%						
May	1,112	157	12.4%	510	739	59.2%						
Average	811	128	15.0%	402	597	59.7%	902	103	12.0%	544	606	54.5%

Table 12-103 shows that on average, 67.0 percent of late outage requests which were not modeled in the Monthly Balance of Planning Period FTR Auction, submitted after the Monthly Balance of Planning Period FTR Auction bidding opening dates, were approved and completed in the first 10 months of the 2025/2026 planning period, compared to 67.0 percent in the 2024/2025 planning period.

Table 12-103 Late transmission facility outage requests: June 2024 through March 2026

	2024/2025			2025/2026		
	Completed Outages	Total	Percent Complete	Completed Outages	Total	Percent Complete
Jun	361	566	63.8%	494	732	67.5%
Jul	380	541	70.2%	421	655	64.3%
Aug	359	482	74.5%	482	631	76.4%
Sep	360	530	67.9%	386	600	64.3%
Oct	472	733	64.4%	463	735	63.0%
Nov	367	530	69.2%	454	609	74.5%
Dec	324	487	66.5%	371	554	67.0%
Jan	348	546	63.7%	297	566	52.5%
Feb	341	530	64.3%	534	721	74.1%
Mar	496	785	63.2%	168	255	65.9%
Apr	438	696	62.9%			
May	537	739	72.7%			
Average	399	597	67.0%	407	606	66.9%

Table 12-103 shows that only 1.1 percent of all outage requests were modeled in the Annual FTR Auction in the first 10 months of the 2025/2026 planning period, and 2.2 percent were modeled in the 2024/2025 planning period. For Monthly FTR Auctions in the first 10 months of the 2025/2026 planning period, an average of 18.4 percent of all outage requests were modeled, and 25.7 percent were modeled in the 2024/2025 planning period.

Table 12-104 FTR market modeled transmission facility outage requests: June 2024 through March 2026

	2024/2025 (12 months)			2025/2026 (10 months)		
Planned Duration	Annual Modeled	Monthly Modeled	Total	Annual Modeled	Monthly Modeled	Total
<2 weeks	101	3,220	3,321	30	1,995	2,025
>=2 weeks & <2 months	162	1,305	1,467	47	789	836
>=2 months	173	644	817	124	447	571
Total	436	5,169	5,605	201	3,231	3,432
All outage requests			20,081			17,593
Percent of Modeled	2.2%	25.7%	27.9%	1.1%	18.4%	19.5%

Transmission Facility Outage Analysis in the Day-Ahead Energy Market

Transmission facility outages also affect the energy market. Just as with the FTR market, it is critical that outages that affect the operating day are known prior to the submission of offers in the day-ahead energy market so that market participants can understand market conditions and PJM can accurately model market conditions in the day-ahead market. PJM requires transmission owners to submit changes to outages scheduled for the next two days no later than 09:30 am. [226]

There are three relevant time periods for the analysis of the impact of transmission outages on the energy market: before the day-ahead market is closed; when the day-ahead market save cases are created; and during the operating day. The list of approved or active outage requests before the day-ahead market is closed is available to market participants in eDART. The day-ahead market model uses outages included in the day-ahead market save cases as an input. The outages that actually occurred during the operating day are the outages that affect the real-time market. If the three sets of outages are the same, there is no potential impact on markets. If the three sets of outages differ, there is a potential negative impact on markets. For example, if the list of outages before the day-ahead market was closed was different from the list of outages that included in the day-ahead market save cases, the day-ahead market participant would have inconsistent outage information as what day-ahead market model used.

For example for the operating day of June 30, 2025, Figure 12-7 shows that: there were 278 approved or active outages seen by market participants before the day-ahead market was closed; there were 363 outage requests included in the day-ahead market model; there were 344 outage requests included in both sets of outages; there were 85 outage requests approved or active before the day-ahead market was closed but not included as inputs in day-ahead market model; and there were 65 outage requests included in day-ahead market model but not available to market participants prior to the day-ahead market.

226 PJM, "Manual 3: Transmission Operations," Rev. 70 (Mar. 4, 2026).

Figure 12-7 Illustration of day-ahead market analysis: June 30, 2025

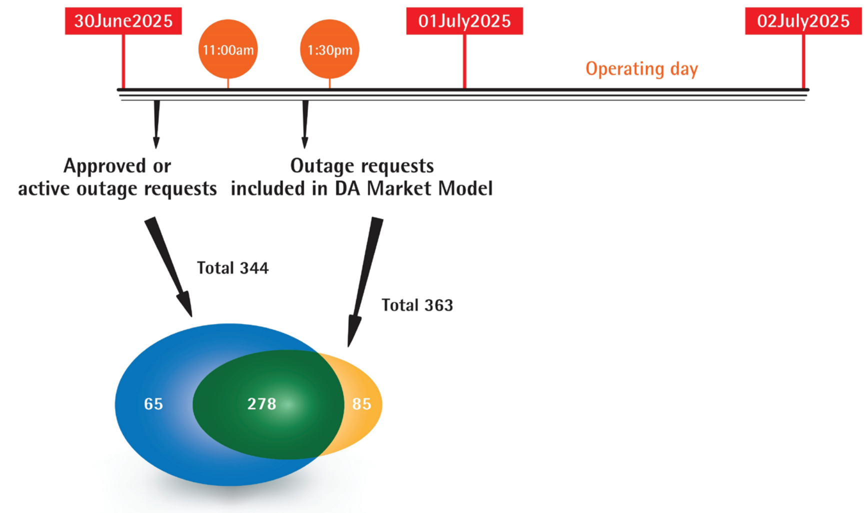


Figure 12-8 compares the weekly average number of active or approved outages available to market participants prior to the close of the day-ahead market with the outages included as inputs to the day-ahead market by PJM.[227] Figure 12-8 shows that the number of outages modeled in the day-ahead market during the spring and fall has increased since 2021 (blue line), but many of these outages were not visible to market participants (gray line).

227 The analysis and figures in this report (Figure 12-8, Figure 12-9, and Figure 12-10) are based on a revised method (relative to the method used in prior State of the Market Reports) that correctly accounts for outages that did not, at the time the outage was active, have an end date specified on the outage ticket.

Figure 12-8 Approved or active outage requests: January 2015 through March 2026

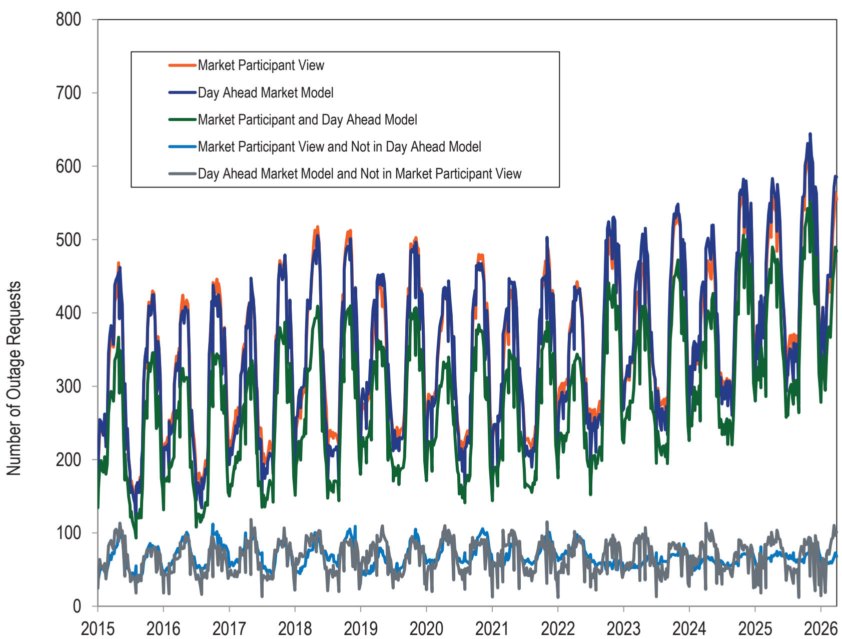


Figure 12-9 compares the weekly average number of outages included in the day-ahead market with the outages that actually occurred during the operating day. Figure 12-9 shows that beginning in 2021, the weekly average number of outages included in the day-ahead market (dark blue line) was higher in the spring and fall than previous years, but many of these outages did not actually occur in the real-time market (gray line). For example, some outages were scheduled to occur in day-ahead based on the information provided in eDART, but were cancelled or rescheduled in real time due to weather, equipment availability, reliability concerns, or the discretion of the transmission owner.

Figure 12-9 Day-ahead market model outages: January 2015 through March 2026

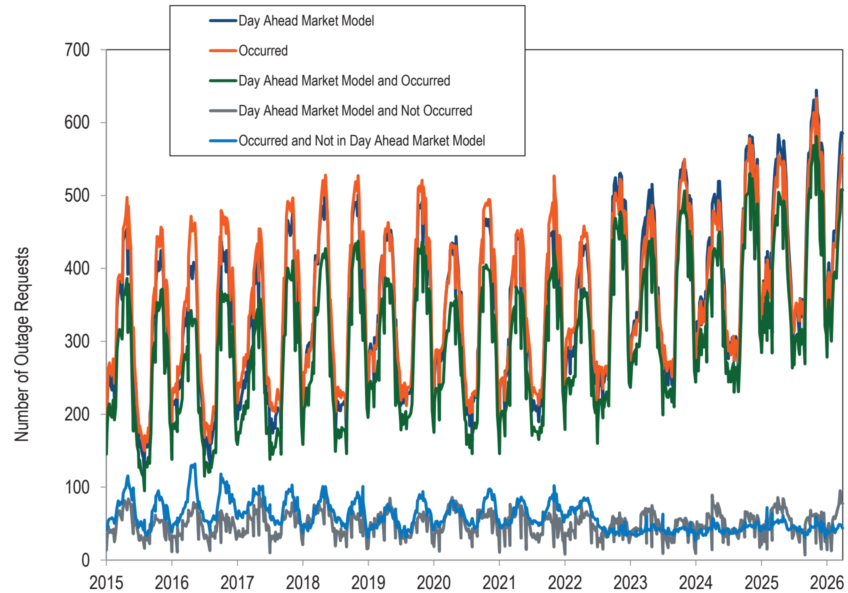


Figure 12-10 compares the weekly average number of active or approved outages for which information was visible to market participants through eDART prior to the close of the day-ahead market with the outages that actually occurred in the real-time market during the operating day. Figure 12-10 shows the number of outages visible to market participants in eDART, but not actually occurring in the real-time market, varies from less than 10 to over 100 in any given week.

Figure 12-10 Approved or active outage requests: January 2015 through March 2026

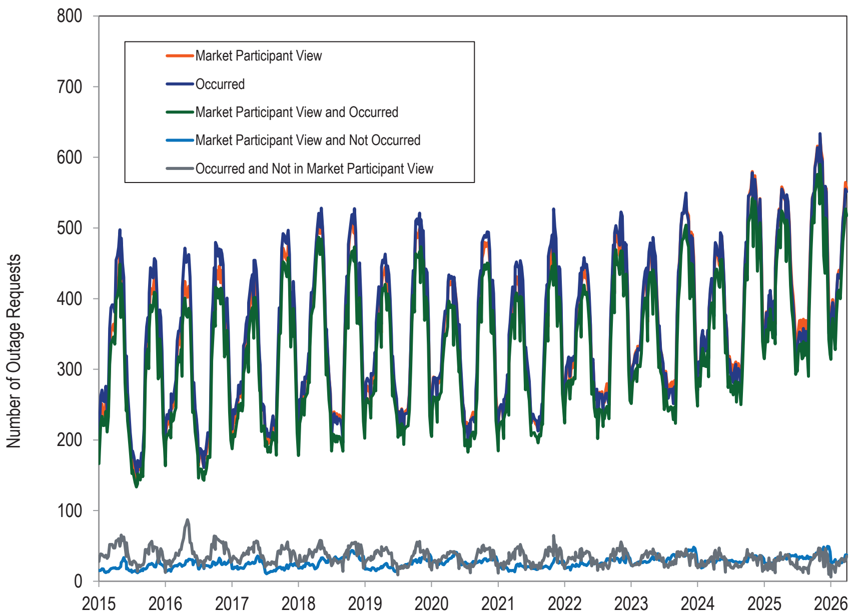


Figure 12-8, Figure 12-9, and Figure 12-10 show that on a weekly average basis, for the full years 2023, 2024, 2025, and the first three months of 2026, the active or approved outages for which information was visible to day-ahead market participants, the outages included as inputs in the day-ahead market model and the outages that actually occurred in real time are not consistent.

13 Financial Transmission and Auction Revenue Rights

In an LMP market, the lowest cost generation is dispatched to meet the load, but when there are transmission constraints, load pays the high local price for all generation, including the low cost generation serving part of that load. The low cost generation receives payment only for its low local price and does not receive the payment made by load for the output of the low cost generation at the high local price. The result is that load pays the correct local price but pays too much in total for energy because it is paying more for the low cost generation than the low cost generation receives. Load pays the difference between the high local price and the low local price of the low cost generation. That payment is appropriately not made to the low cost generation which is paid its LMP. In an LMP market, load pays more than generation receives. FTRs are the mechanism for returning those excess payments to load. But the current FTR mechanism in PJM does not and cannot return all the excess payments to load. The FTR mechanism in PJM needs a significant redesign in order to achieve that objective. The FTR mechanism has become unduly complicated and has deviated significantly from its original purpose. Return of all the excess payments to load would result in a perfect hedge against congestion. The current FTR mechanism has significantly attenuated the value of the FTR/ARR design as a hedge against congestion for load.

The FTR mechanism should be a simple accounting method for assigning congestion rights to load. But PJM has added increasingly complex rules and regularly intervenes in the FTR mechanism as the PJM FTR design has moved further and further from these economic fundamentals. Some market participants have profited in various ways from these design flaws and those market participants now strongly defend the current design in the PJM stakeholder process and at FERC. The customers who ultimately pay congestion are generally not aware of the current, flawed FTR design and do not understand the extent to which the current design fails to offset their congestion payments compared to a fundamentally correct FTR design that would return congestion to load.

When the lowest cost generation is remote from load centers, the physical transmission system permits that lowest cost generation to be delivered to load, subject to transmission limits. This was true prior to the introduction of LMP markets and continues to be true in LMP markets.

After the introduction of LMP markets in PJM, financial transmission rights (FTRs) were introduced, effective April 1, 1999, for the real-time market and June 1, 2000, for the combined day-ahead and real-time (balancing) markets. FTRs permitted the loads, which pay for the transmission system, to continue to receive the economic benefits of access to either local or remote low cost generation by returning congestion to the load.[1] FTRs and the associated congestion revenues were directly provided to load in recognition of the fact that, as a result of LMP, load was required to pay more for low cost generation than is paid to low cost generation. But there was a flaw built in from the very beginning of the PJM FTR design that had no significant impact initially but which was ultimately the source of all the issues with the FTR mechanism. That flaw was the idea that congestion was based on contract paths in a network system rather than a result of the actual operation of the complex network. Prior to the introduction of LMP markets, payment for the delivery of low cost generation to load was based both on intrazonal generation and intrazonal transmission, both under cost of service rates, and on contracts with specific remote generation outside the local zone and the associated point to point transmission contracts. Most load was served by intrazonal generation. In both cases, customers paid for the physical rights associated with the transmission system used to provide for the delivery of low cost generation to load. There was no congestion revenue because customers paid only the actual cost of the low cost generation. The flawed idea that congestion is based on contract paths was inconsistent with the most basic logic of LMP and the resultant fissure has continued to widen. FTRs were a core part of the LMP design. FTRs ensured that the introduction of locational marginal pricing would not result in overpayments by load. The origin of FTRs was the recognition that the way to hold load harmless from making the excess payments created by the LMP system was to return the excess payments to load. The rights to congestion belong to load. If implemented

1 See 81 FERC ¶ 61,257 at 62,241 (1997).

correctly, FTRs would be the financial equivalent of firm transmission service for load. If implemented correctly, FTRs would be a perfect hedge against congestion for load. The result of the current FTR mechanism is a significant reduction in the value of FTRs as a hedge for load. The current FTR mechanism results in significant wealth transfers from the load that pays congestion to traders of FTRs and traders of virtuals. The current FTR mechanism results in uneven and arbitrary differences in the share of congestion returned to load, depending on location and PJM's assignment of ARRs.

The notion that FTRs exist in order to provide a hedge for generation is a fallacy. In an LMP system, the basic incentive structure for generation derives from the fact that generation is paid the LMP at the generator bus. If generation were to be guaranteed a price at a distant constrained load bus rather than at the generation bus, there would be no incentive for generation to locate where it is needed on the system. In addition, the payment of the price at the generator bus is fundamental to the logic of locational marginal pricing which produces local prices equal to the marginal value of generation at every point. There is no logical or theoretical basis in locational marginal pricing for the assertion that generation at low price nodes is underpaid and should be paid more from congestion dollars. Generation does not pay congestion. Some generation receives a price lower than the system marginal price (SMP) and some generation receives a price greater than SMP, but that does not mean that generation is paying congestion. It means that generation is being paid an LMP that is higher or lower than the system load-weighted average LMP. If a generating unit wants a hedge, it may enter into an arm's length transaction with a willing counter party as a hedge. That is the way hedges work in markets. That is not the purpose of FTRs.

In an LMP system, the only way to ensure that load receives the benefits associated with the use of the transmission system to deliver low cost energy is to use FTRs, or an equivalent mechanism, to pay back to load the difference between the total load payments and the total generation revenues. FTRs are a core theoretical part of the LMP design and were included in the PJM market design to offset the congestion costs that load pays in an LMP market. Congestion revenues are the source of the funds to pay FTRs. Congestion revenues should be assigned to the load that paid them through FTRs.[2] The only way to ensure that load receives the benefits associated with the use of the transmission system to deliver low cost energy is to ensure that all congestion revenues are returned to load or, more precisely, that the rights to all congestion revenues are assigned to load. In order to do that, congestion payments must be defined correctly based on the way that power actually flows in the PJM network and not based on arbitrary contract paths.

Effective April 1, 1999, when FTRs were introduced with the LMP market, there was a real-time market but no day-ahead market, and FTRs returned real-time congestion revenue to load. Effective June 1, 2000, the day-ahead market was introduced and FTRs returned total congestion including day-ahead and real-time (balancing) congestion to load.[3] Congestion is the sum of day-ahead and balancing congestion. Effective June 1, 2003, PJM replaced the direct allocation of FTRs to load with an allocation of Auction Revenue Rights (ARRs). Under the ARR design, the load still owns the rights to congestion revenue, but the ARR design allows load to either claim the FTRs directly (through a process called self scheduling), or to sell the rights to congestion revenue in the FTR auction in exchange for a revenue stream based on the auction clearing prices of the FTRs. Under the ARR design, the right to all congestion revenues should belong to load and load should have the ability to retain or sell the congestion revenue rights on terms that load defines and accepts. The actual ARR implementation produces a very different result and fails to assign all congestion revenue rights to load.

ARRs were an add on concept, defined based on a misunderstanding of FTRs, which had its roots in the assignment of congestion to load using contract paths (generation to load paths) rather than on the calculation of congestion actually paid. Contract paths are a fiction in a network. ARRs used assumed contract paths to assign congestion to load. The use of contract paths for ARRs was a more critical mistake than using contract paths for FTRs because contract paths did not, do not, and cannot account for all congestion. The use of contract paths led to the mistaken conclusion that there was some excess congestion that did not belong to load and could be sold to FTR buyers. The

2 See *id.* at 62, 259–62,260 & n. 123
3 PJM refers to the combination of the day-ahead and real-time (balancing) markets as a two settlement system.

ARR concept, as it is currently implemented, does not allow the FTR sellers, load, to establish a price at which they are willing to sell, but forces load to accept whatever prices buyers are willing to pay. The revenue from the sale of congestion rights is not even paid in full to ARR holders. Sellers are required to return some of the cleared auction revenue to FTR buyers when FTR payments are less than target allocations. So called surplus revenue is paid to FTR holders to ensure payment, despite the fact that willing FTR buyers paid the revenues in the auction for the rights to an uncertain level of congestion.

The use of generation to load contract paths, rather than the direct calculation of congestion, led to an increased divergence between FTR target allocations on the generation to load contract paths and actual total congestion. This divergence between actual network use and historic contract paths was exacerbated as new zones were added with their own historic generation to load contract paths and as significant numbers of generating units retired and new units were added.[4] Rather than understanding that the divergence resulted from the fact that a contract path based approach did not correctly calculate congestion in a network system, especially as the system grew significantly, the issue was characterized as the existence of excess capacity on the transmission system. But congestion was never about capacity on the transmission system. Prior to the introduction of ARRs, the so called excess congestion that exceeded the congestion on the defined contract paths was returned to load, regardless of its source. There is no such thing as excess congestion. Congestion is congestion. In a well designed LMP/FTR system, all congestion is returned to load, neither more nor less. The overlay of ARRs on the FTR concept did not change the fundamental logic of congestion, but permitted the introduction of a system in which the divergence was formally created between the amount of congestion paid by load and the amount of congestion returned to load. Congestion belongs to the load, by definition. The introduction of ARRs based on the contract path fiction undermined the assignment of all congestion rights to load.

4 For a comprehensive report on capacity retirements and capacity additions in PJM, see: "2020 PJM Generation Capacity and Funding Sources: 2007/2008 through 2021/2022," (September 15, 2020) available at <http://www.monitoringanalytics.com/reports/Reports/2020/Constraint_Based_Congestion_Calculations_20200722.pdf>.

FTR revenue adequacy, like surplus congestion revenue, is a misnomer. FTR revenue adequacy, as defined in PJM rules, is an artifact of the flawed design of the current approach to FTR/ARRs. If FTRs only returned congestion to FTR holders, there could be no such thing as revenue inadequacy. As currently defined in PJM, FTR revenue adequacy simply compares day-ahead congestion revenues to FTR target allocations. (Target allocations are the day-ahead CLMP differences, shadow prices, between the source and sink of the FTR times the MW of the FTR.) There is no reason to expect congestion revenues to equal FTR target allocations under the path based approach. There are systematic differences between FTR target allocations and actual congestion in aggregate and on a path by path basis. Revenue adequacy is not a benchmark for how well the FTR process is working. Target allocations are not congestion. FTR revenue adequacy is not equivalent to the adequacy of ARRs as an offset for load against total congestion. A path specific target allocation is not a guarantee of payment. Yet PJM treats target allocations as a guarantee of payment and takes what is termed surplus auction revenue from ARR holders (load) and gives it to FTR holders when day-ahead congestion revenues are not enough to cover all FTR target allocations.

The contract path fiction is also the source of the incorrect definition of the product that is bought and sold as FTRs, the available supply of the product and the price paid to the buyers of the product. The FTR product is defined as the difference in congestion prices in the day-ahead market only, across specific transmission contract paths (the shadow price), multiplied by the FTR MW position on those paths. That is the definition of FTR target allocation. The difference in congestion prices across contract paths is not congestion and is not equal to congestion revenues when multiplied by the FTR MW position. The MW quantity of the product made available for sale in the FTR auctions is defined as system capability, meaning the capacity of the transmission system to deliver power. But system capability is not actual market flows and system capability is not congestion and system capability is not the difference in congestion prices across transmission contract paths nor the potential for such difference. Congestion is defined as the difference in congestion prices across a path multiplied by the market flow on that path, recognizing both day-ahead and balancing market results. That is the measure of the amount load pays in excess of what generation receives. The definition of ARRs based on contract paths led to the mistaken idea that some transmission system capacity was used by ARRs but some was not and that both the ARR capability and the excess capability was available for sale as FTRs. This fundamental confusion in the design of the market is the source of so called revenue shortfalls, of the redesign of the market to exclude balancing congestion, and of the need for PJM to intervene in the market. PJM has had to regularly intervene in the market because the market as designed cannot reach equilibrium based on the economic fundamentals. The product, the quantity of the product, and the price of the product are all incorrectly defined.

The ARR/FTR design does not serve as an efficient mechanism for returning congestion to load as a result of an FTR design that was flawed from its introduction and as a result of various distortions added to the design since its introduction. The distortions include the definition of target allocations based on day-ahead price differences only, the fact that ARR holders cannot set the sale price for the congestion revenue rights they own, the return of market revenues to FTR buyers when profit targets are not met, the failure to assign all FTR auction revenues to ARR holders, the differences between modeled and actual system capability, the definition and allocation of surplus, and the numerous cross subsidies among participants. The fundamental distortion was the assignment of the rights to congestion revenue based on specific generation to load transmission contract paths. This approach retained the contract path based view of how load is served that is fundamentally inconsistent with the way load is actually served in a network system and therefore inconsistent with the role of FTRs in a nodal, network system with locational marginal pricing.

The cumulative offset of congestion by ARRs for the 2011/2012 planning period through the first ten months of the 2025/2026 planning period, using the rules effective for each planning period, was only 66.0 percent. Only 66.0 percent of congestion revenue was returned to load over this period. Load was underpaid by $6.8 billion from the 2011/2012 planning period through the first ten months of the 2025/2026 planning period. This is an increase of $1.9 billion in underpayment to load from the end of the 2024/2025 planning period through the first ten months of the 2025/2026 planning period.

The overall underassignment of congestion to load includes dramatically different results by zone. Load in some zones receives congestion revenues well in excess of the congestion they pay while the reverse is true for other zones.

If the original PJM FTR approach had been designed to return congestion revenues to load without use of the 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. The design should simply have provided for the return of all congestion revenues to load. The design should have also provided for the ability of load to sell the rights to congestion revenue. That sale could be organized as an FTR auction with the product and the price clearly defined. Now is a good time to address the issues of the FTR design and to return the design to its original purpose. This would eliminate much of the complexity associated with ARRs and FTRs and eliminate unnecessary controversy about the appropriate recipients of congestion revenues.

The *2026 Quarterly State of the Market Report for PJM: January through March* focuses on the 2025/2026 planning period as well as the 2025/2028 Long Term auction, the 2025/2026 Annual FTR auction and the 2025/2026 ARR allocation, specifically covering June 1, 2025, through March 31, 2026. 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 2026. [5]

5 The MMU identified missing and erroneous distribution factors and shadow prices, primarily within the pricing run. The calculation of generator sensitivity factors requires accurate distribution factors and shadow prices. Where available, MMU used distribution factors from the dispatch run. MMU also calculated missing shadow prices for the relevant transmission constraints when feasible. This approach reduced the impact of the errors to 0.2 percent of all FTR target allocations within the affected month. Figures and Tables that are affected by this error are indicated with a footnote.

Table 13-1 The FTR/ARR 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 2025/2028 Long Term FTR Auction, the 2025/2026 Annual FTR Auction and each period of the Monthly Balance of Planning Period Auctions for prevailing flow FTRs. The ownership of FTR obligations is unconcentrated or moderately concentrated for each period of the Monthly Balance of Planning Period Auctions for counter flow FTRs. The ownership of FTR options is moderately or highly concentrated for every Monthly FTR Auction period and unconcentrated for the 2025/2026 Annual FTR Auction. Ownership of current FTRs is disproportionately (89.2 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.

Overview

Auction Revenue Rights

Market Design

- **ARR Target Allocations.** The value of ARRs is defined by the nodal price differences from the Annual FTR Auction and Monthly FTR Auctions, times the MW of the ARR. ARR target allocations are the minimum value of an ARR. If any ARRs are deficient at the end of the planning period, deficient ARR holders will receive an uplift payment that will charged to FTR holders. If FTRs are fully funded at the end of the planning period, ARR holders will receive all surplus congestion revenues, proportional to ARR target allocations.

Market Structure

- **ARR Ownership.** In the 2025/2026 planning period, ARRs were allocated to 1,560 individual participants, held by 130 parent companies, up from 1,523 individual parents, held by 126 parent companies in the 2024/2025 planning period. ARR ownership for the 2025/2026 planning period was unconcentrated with an HHI of 600, down from 610 for the 2024/2025 planning period.

Market Behavior

- **Self Scheduled FTRs.** For the 2025/2026 planning period, 25.9 percent of eligible ARRs were self scheduled as FTRs, up from 25.3 percent for the 2024/2025 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 2025/2026 planning period, ARRs and self scheduled FTRs offset only 55.3 percent of total congestion. Congestion payments by load in some zones were more than offset and congestion payments in other zones were less than offset. Load has been underpaid congestion revenues by $6.8 billion from the 2011/2012 planning period through the first ten months of the 2025/2026 planning period. The cumulative offset for that period was only 66.0 percent of total congestion. If ARR holders had self scheduled all of their allocated ARRs as FTRs for the first ten months of the 2025/2026 planning period, the self scheduled FTR target allocations would have increased the offset from 55.3 percent to 67.9 percent of total congestion.

- **ARR Payments.** For the first ten months of the 2025/2026 planning period, the ARR target allocations, which are defined by the nodal price differences from the Annual FTR Auction and Monthly FTR Auctions times the MW of the ARR, were $1,882.7 million, while PJM collected $2,137.0 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions. For the 2024/2025 planning period, the ARR target allocations were $1,448.1 million while PJM collected $1,664.9 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions.

- **ARR Revenue.** For the first ten months of the 2025/2026 planning period there was enough total day-ahead congestion to pay FTR target allocations. However, as a result of the monthly settlement logic for FTRs and ARRs, $93.2 million of FTR auction revenue over ARR target allocations was transferred from ARR holders (load) to FTR holders. In the 2024/2025 planning period all $196.2 million of FTR auction revenue over ARR target allocations was transferred from ARR holders 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 2025/2026 planning period, as a result of transmission being returned to service from outages included in the annual model, PJM allocated a total of 25,401.9 MW of residual ARRs, down 2,632.2 MW (a 9.4 percent decrease) from 28,034.1 MW, with a total target allocation of $76.0 million, up $53.9 million (a 243.8 percent increase) from $22.1 million in the same period of the 2024/2025 planning period.

- **ARR Deficiency.** In July 2025, there was not enough FTR auction revenue collected from the monthly FTR auction to pay the high target allocations from Residual ARRs. As a result, July ARR funding was deficient for the first time since ARRs were introduced. Deficient ARRs will be funded at the end of the planning period from surplus FTR revenues, if there is an FTR surplus, or through an uplift charge to FTR holders if there is not an FTR surplus.

- **ARR Reassignment for Retail Load Switching.** There were 31,342 MW of ARRs associated with $1.6 million of revenue that were reassigned for the first ten months of the 2025/2026 planning period. There were 27,940 MW of ARRs associated with $0.9 million of revenue that were reassigned in the same period of the 2024/2025 planning period.

Financial Transmission Rights

Market Design

- **FTR Target Allocations.** The value of FTRs is defined as the day-ahead CLMP difference between the source and sink of the FTR times the MW of the FTR. FTR Target allocations are the maximum value of an FTR. If the FTR target allocations are greater than the congestion revenue paid in the planning period, payments to all FTRs are prorated, proportional to FTR target allocations.
- **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.**[6] For the Monthly Balance of Planning Period Auctions, financial entities purchased 96.6 of all prevailing and counter flow FTRs, including 95.5 percent of prevailing flow and 97.9 percent of counter flow FTRs for the first ten months of the 2025/2026 planning period. Financial entities owned 89.2 percent of all prevailing and counter flow FTRs, including 82.9 percent of all prevailing flow FTRs and 96.0 percent of all counter flow FTRs during the first ten months of the 2025/2026 planning period. Self scheduled FTRs account for 3.4 percent of all FTRs held.
- **Market Concentration.** In the Monthly Balance of Planning Period Auctions for the first ten months of the 2025/2026 planning period, ownership of cleared prevailing flow bids was unconcentrated in all periods. Ownership of cleared counter flow bids was unconcentrated in 68.0 percent of periods and moderately concentrated in 32.0 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 2025/2028 Long Term FTR Auction, total participant FTR sell offers were 1,557,455 MW. In the 2025/2026 Annual FTR Auction, total participant FTR sell offers were 1,695,004 MW. In the Monthly Balance of Planning Period FTR Auctions for the first ten months of the 2025/2026 planning period, total participant FTR sell offers were 63,538,283 MW.
- **Buy Bids.** In the 2025/2028 Long Term FTR auction, total FTR buy bids were 6,729,000 MW, up 72.0 percent from 5,729,618 MW the previous long term auction. There were 6,658,483 MW of buy and self scheduled bids in the 2025/2026 Annual FTR Auction, up 39.6 percent from 4,770.381 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 2025/2026 planning period were 84,841,572 MW.
- **FTR Forfeitures.** Total FTR forfeitures were $4,082,718 for the first ten months of the 2025/2026 planning period, up 30.1 percent from $3,138,663 from the same period of the 2024/2025 planning period.
- **Credit.** There were two collateral defaults and four payment defaults in the first three months of 2026.

Market Performance

- **Quantity.** In the 2025/2028 Long Term FTR Auction 923,869 MW (13.7 percent) of buy bids cleared and 168,852 MW (10.8 percent) of sell offers cleared. In the 2025/2026 Annual FTR Auction 1,324,299 MW (19.9 percent) of buy and self scheduled bids cleared, up 28.8 percent from the 2024/2025 Annual FTR Auction, and 183,410 MW (10.8 percent) of sell offers cleared, up 47.6 percent from the 2024/2025 Annual Auction. In the first ten months of the 2025/2026 planning period, Monthly Balance of Planning Period FTR Auctions 15,117,402 MW (17.8 percent) of FTR buy bids cleared, up 46.5 percent from the same period of the

6 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.

2024/2025 planning period and 9,708,906 MW (15.3 percent) of FTR sell offers cleared, up 55.3 percent from the same period of the 2024/2025 planning period.

- **Price.** The weighted average buy bid FTR price in the 2025/2028 Long Term FTR Auction was $0.09 per MW, up from $0.07 from the 2024/2027 Long Term FTR Auction. The weighted average buy bid FTR price in the Annual FTR Auction for the 2025/2026 planning period was $0.50 per MW, up from $0.30 per MW in the 2024/2025 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 2025/2026 planning period was $0.43 per MWh, up from $0.42 in the 2024/2025 planning period.
- **Revenue.** The 2025/2028 Long Term FTR Auction generated $162.3 million of net revenue, up 58.2 percent from $102.6 million from the 2024/2027 Long Term FTR Auction. The 2025/2026 Annual FTR Auction generated $1,895.3 million of net revenue, up 28.5 percent from $1,475.3 million for the 2024/2025 Annual FTR Auction. The Monthly Balance of Planning Period FTR Auctions resulted in net revenue of $88.7 million in the first ten months of the 2025/2026 planning period, up 16.0 percent from $76.5 million in the same period of the 2024/2025 planning period.
- **"Revenue Adequacy."** For the first ten months of the 2025/2026 planning period there was enough total day-ahead congestion revenue to pay FTR target allocations. However, as a result of the monthly settlement logic for FTRs and ARRs, $93.2 million of FTR auction revenue was transferred from ARR holders (load) to FTR holders in months where congestion revenue was less than FTR target allocation, and FTRs were paid 100.0 percent of the target allocations for the first ten months of the 2025/2026 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 2025/2026 planning period, profits for all participants were $1.9 billion, up from $799.0 million in profits in the same time period in the 2024/2025 planning period and the highest level since the 2013/2014 planning period. In the first 10 months of the 2025/2026 planning period, physical entities received $541.8 million in profits on FTRs purchased directly (not self scheduled), up from $54.3 million profits in the same time period in the 2024/2025 planning period. Financial entities received $1.2 billion in profits, up from $744.7 million profits in the same time period in the 2024/2025 planning period.

Markets Timeline

Any PJM member can participate in the Long Term FTR Auction, the Annual FTR Auction and the Monthly Balance of Planning Period FTR Auctions.

Table 13-2 shows the date of first availability and the final closing date for all ARR and FTR auctions for ARRs and FTRs that are effective in the 2025/2026 planning period and for auctions with bidding dates in 2026.[7]

Table 13-2 Annual FTR auction dates

Auction	Initial Open Date	Final Close Date
2022/2025 Long Term	1-Jun-21	3-Mar-22
2023/2026 Long Term	2-Jun-22	3-Mar-23
2024/2027 Long Term	1-Jun-23	5-Mar-24
2025/2028 Long Term	3-Jun-24	5-Mar-25
2025/2026 ARR	5-Mar-25	28-Mar-25
2025/2026 Annual	9-Apr-25	2-May-25
2025/2026 Monthly	15-May-24	17-Apr-26
2026/2029 Long Term	2-Jun-25	4-Mar-26
2026/2027 ARR	4-Mar-26	26-Mar-26
2026/2027 Annual	8-Apr-26	4-May-26
2026/2027 Monthly	14-May-26	Apr-27
2027/2030 Long Term	1-Jun-26	1-Mar-27

7 The results of the 2026/2029 Long Term auction and the 2026/2027 ARR allocation do not include ARRs or FTRs that are effective in the 2025/2026 planning period and are not included in this report.

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.)[8]
- 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.)
- 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.)

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

- 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.[9] (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 that PJM's minimum credit requirements be reviewed and updated to appropriately reflect the risk created for the markets and other market participants. The PJM minimum credit requirements (minimum tangible net worth and minimum tangible assets) were set as fixed dollars amounts in 2011 in FERC Order No. 741 based on the specific market participation (FTRs or other). (Priority: Medium. First reported Q3 2025. Status: Not adopted.)

9 See "PJM Manual 6: Financial Transmission Rights," Rev. 34 (May 21, 2025).

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.

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.[10] The FERC order of September 15, 2016, introduced a subsidy to FTR holders at the expense of ARR holders.[11] 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.

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.[12] 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

10 Such subsidies have been suggested repeatedly. See FERC Dockets Nos. EL13-47-000 and EL12-19-000.
11 See 156 FERC ¶ 61,180 (2016), *reh'g denied*, 158 FERC ¶ 61,093 (2017).
12 163 FERC ¶ 61,165 (2018).

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. For the 2024/2025 planning period, there was not enough congestion revenue to fund FTR target allocations and all FTR auction surplus revenues were taken from load and given to FTR holders. 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 55.3 percent of total congestion paid by load in the first ten months of the 2025/2026 planning period. Load has been underpaid congestion revenues by $6.9 billion from the 2011/2012 planning period through the first ten months of the 2025/2026 planning period. The cumulative offset for that period was only 66.0 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.

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).[13] 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 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.

13 See 178 FERC ¶ 61,170.

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.

Auction Revenue Rights

Auction Revenue Rights (ARRs) are the mechanism used to assign congestion rights to load, using an archaic and invalid contract path based approach, and to sell those rights to FTR buyers in various auctions. ARR values are based on nodal price differences established by cleared FTR bids in the Annual FTR Auction times the MW of the ARR. ARR sellers have no opportunity to define a price at which they are willing to sell and must accept the prices set by FTR buyers. ARR revenues are a function of FTR auction participants' expectations of congestion, risk, competition and available supply. But some auction revenues may be returned to FTR buyers as "surplus," despite the fact that FTR buyers willingly paid a defined price for FTRs. There is no surplus. PJM has significant discretion over the level of supply made available to FTR buyers. That discretion is needed only as a result of the flawed design. As long as the current design persists, the goals of that discretion should be significantly limited and defined clearly in the tariff.

ARRs are available only as obligations (not options) and only as a 24 hour product. ARRs are available to the nearest 0.1 MW. The ARR target allocation is equal to the product of the ARR MW and the price difference between the ARR sink and source from the Annual FTR Auction.[14] The value of annual ARR target allocations is set by the Annual FTR Auction. ARRs would be revenue inadequate if the money collected from the Annual FTR auction is not enough to pay the entirety of Annual ARR target allocations for the planning period which could happen only if there is a modeling difference between the system model used for ARRs and the system model used for FTRs and the FTR MW are reduced. The Annual FTR Auction and annual ARR target allocations were not the issue in the first ten months of the 2025/2026 planning period. Residual ARR target allocations are set by Monthly FTR auctions (the month that they are awarded). The large increase in Residual ARR target allocations compared to Annual ARR target allocations and FTR Auction Revenue in the first three months of the 2025/2026 planning led to the first month with an ARR deficiency in the history of the ARR market. An ARR's target allocation can be a positive or negative depending on the price difference between sink and source. Residual ARR target allocations can only be positive.

The goal of the ARR/FTR design should be to provide an efficient mechanism to ensure that load receives the rights to all congestion revenues. In the current design, all auction revenues should be paid to ARR holders.

The quantity of the product made available as ARRs or for sale in the FTR auctions is defined as system capability, meaning the capacity of the transmission system to deliver power. But system capability is not congestion

14 These nodal prices are a function of the market participants' annual FTR bids and binding transmission constraints.

and system capability is not the difference in congestion prices across transmission contract paths nor the potential for such difference and system capability is not the market flow across transmission paths. The concept of system capability is not relevant to assigning the rights to congestion revenues to load. The use, or misuse, of the concept of system capability in assigning ARRs is derived entirely from the contract path approach used in the PJM design. The definition of ARRs based on contract paths led to the mistaken idea that some transmission system capacity was used by ARRs but some was not and that both the ARR capability and the excess capability were available for sale as FTRs. Power does not flow on contract paths. In the current approach, system capability available to ARR holders is limited by the system capability made available in PJM's annual FTR transmission system market model. PJM's annual FTR transmission market model represents annual, expected system capability, modified by PJM to achieve PJM's goal of guaranteeing revenue equal to target allocations for FTRs, and subject to the requirement that all Stage 1A ARR requests must be allocated. Stage 1A ARR right requests are guaranteed and system capability necessary to accommodate the rights must be included in PJM's annual FTR transmission system market model despite the fact that there are not real world paths, real world capability, or real world flows that correspond to Stage 1A rights.

Market Design

ARRs have been available to network service and firm, point to point transmission service customers since June 1, 2003, when the annual ARR allocation was first implemented for the 2003/2004 planning period. The initial allocation covered the Mid-Atlantic Region and the APS Control Zone. For the 2006/2007 planning period, the choice of ARRs or direct allocation FTRs was available to eligible market participants in the AEP, DAY, DUQ and DOM Control Zones. For the 2007/2008 and subsequent planning periods through the present, all eligible market participants were allocated ARRs.

Each March, PJM allocates annual ARRs to eligible customers in a three stage process: Stage 1A, Stage 1B and Stage 2B. Stage 1A ARRs are assigned based on historic contract paths and Stage 1A ARRs must be preserved for at least ten planning periods regardless of system or regulatory changes.[15]

The 2022/2023 planning period annual auction was the first auction under PJM's new ARR allocation rules. Under the new rules, Stage 1A ARR allocations increase from 50 percent of Network Service Base Load (NSBL) to 60 percent of Network Service Peak Load (NSPL).[16] NSBL is a network service customer's contribution to the lowest daily zonal peak load in the prior 12 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.

In Stage 1A, LSEs can obtain ARRs, based on their contribution to the network service peak load (NSPL) and based on putative generation to load contract paths, or their qualified replacements if the resource has retired and PJM has replaced it with a different generator regardless of whether there is a contract. The historical reference year is the year in which PJM markets were implemented, which is 1999 for the original zones, or the year in which a zone joined PJM. Firm, point to point transmission service customers can obtain Stage 1A ARRs up to 50 percent of the MW of firm, point to point transmission service provided between the receipt and delivery points for the historical reference year, subject to a cap of 60 percent of the participants total network service peak load for the zone or load aggregation zone that the ARRs are obtained. Effective for the 2023/2024 planning period, network service customers can obtain Stage 1A ARRs based on the MW of firm service provided during the reference year, subject to a cap of 60 percent of the participants total network service peak load for the zone or load aggregation zone that the ARRs are obtained. Stage 1A ARRs cannot be prorated. If Stage 1A ARRs are found to be infeasible, transmission system upgrades must be undertaken to maintain feasibility.[17] However, PJM does not actually upgrade the transmission system to address Stage 1A ARR infeasibility because there is no actual physical infeasibility. The apparent infeasibility is an artificial result

15 See "PJM Manual 6: Financial Transmission Rights," Rev. 34 (May 21, 2025) at 20.
16 See 178 FERC ¶ 61,170.
17 See "PJM Manual 6: Financial Transmission Rights," Rev. 34 (May 21, 2025).

based on the fiction that power flows on the unsupported, outdated, fictional and irrelevant generation to load contract paths on which PJM's current and incorrect ARR allocation is based. Stage 1A rights have nothing to do with actual power flows or transmission limits.

In Stage 1B, network transmission service customers can obtain ARRs, up to the difference between their share of network service peak load and Stage 1A allocations. Effective for the 2023/2024 planning period, Stage 1B ARRs can be obtained from historical generation resources, qualified replacement resources, hubs, zones, or interfaces to designated load aggregation zones. Firm, point to point transmission service customers can obtain ARRs based on the MW of long-term, firm, point to point service provided between the receipt and delivery points for the historical reference year.

In Stage 2, network transmission service customers can obtain ARRs from any hub, control zone, generator bus or interface pricing point to any part of their aggregate load in the control zone, load aggregation zone, or any generator, interface, hub or zone, up to their total peak network load in that zone. Firm, point to point transmission service customers can obtain ARRs consistent with their transmission service as in Stage 1A and Stage 1B.

ARR holders can self schedule ARRs as FTRs during the Annual FTR Auction.[18] When ARR holders self schedule FTRs, the ARR holders choose to be paid based on variable FTR target allocations rather than the fixed ARR value determined in the annual FTR auction. ARRs can be traded between LSEs prior to the first round of the Annual FTR Auction.

Effective for the 2015/2016 planning period, when residual zonal pricing was introduced, ARRs default to sinking at the load settlement point if different than the zone, but the ARR holder may elect to sink their ARR at the zone instead.[19]

In 2016, FERC ordered PJM to remove retired resources from the generation to load contract paths used to allocate Stage 1A ARRs.[20] PJM replaced retired units with operating generators, termed qualified replacement resources (QRRs), regardless of whether there was a corresponding contract.[21] Existing Stage 1A resources retain their current allocations, while ARR allocations to QRRs that replace retired Stage 1A resources are prorated based on the feasibility of these ARRs after existing resources are allocated. As a result of this proration, ARRs for QRRs have lower priority than ARRs from generators that existed in 1998.

Generation to load paths, even from active generators, are based on a contract path model rather than a network model. Generation to load contract paths should not be used as a basis for assigning the rights to congestion revenue. There is no basis for assuming that a contract existed in 1999 or exists currently. Contract paths are a fiction and are not an accurate representation of the reasons that congestion exists or of how load is served in a network and will, by definition, not accurately measure the exposure of load to congestion.

Market Structure

ARRs are allocated on an annual basis. For the 2025/2026 planning period there were 1,560 individual participants and 130 parent companies, up from 1,523 individual participants and 126 parent companies for the 2024/2025 planning period.

The ownership of ARRs by parent company was unconcentrated, with an HHI of 600, for the 2025/2026 planning period compared to 610 for the 2024/2025 planning period.

Market Performance

Volume

Table 13-3 shows the MW of ARR allocations for each round of the 2024/2025 and 2025/2026 planning periods. There was a 3,011 MW increase (1.9 percent) in Network Service Peak Load (NSPL) between the 2024/2025 and 2025/2026 planning period. This increase resulted in an increase in ARR MW requested by load in the annual auction of 1,858 MW (0.9 percent) from the 2024/2025 to the 2025/2026 planning period. The ARR MW actually provided to load decreased by 1,559 MW (1.4 percent) from the 2024/2025 to the 2025/2026

18 OATT Attachment K 7.1.1.(b).

19 See "PJM Manual 6: Financial Transmission Rights," Rev. 34 (May 21, 2025) at 35.

20 156 FERC ¶ 61,180 (2016) *reh'g denied*, 158 FERC ¶ 61,093 (2017).

21 See FERC Docket No. EL16-6-003.

planning period. The cleared volume of Stage 1B ARR MW decreased 3.4 percentage points from 26.5 percent in the 2024/2025 planning period to 23.1 percent in the 2025/2026 planning period.

Table 13-3 Annual ARR allocation volume: 2024/2025 and 2025/2026 planning periods

Planning Period	Stage	Round	Requested Count	Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
2024/2025	1A	0	33,729	86,657	86,657	100.0%	0	0.0%
	1B	1	11,182	56,080	14,880	26.5%	41,200	73.5%
	2	2	14,374	31,556	5,691	18.0%	25,865	82.0%
		3	9,552	31,520	7,788	24.7%	23,732	75.3%
		Total	23,926	63,076	13,479	21.4%	49,597	78.6%
	Total		68,837	205,813	115,016	55.9%	90,797	44.1%
2025/2026	1A	0	35,072	89,253	89,245	100.0%	8	0.0%
	1B	1	10,807	55,826	12,919	23.1%	42,907	76.9%
	2	2	9,006	31,316	5,261	16.8%	26,055	83.2%
		3	6,660	31,276	6,032	19.3%	25,244	80.7%
		Total	15,666	62,592	11,293	18.0%	51,299	82.0%
	Total		61,545	207,671	113,457	54.6%	94,214	45.4%

Table 13-4 shows the share of ARR MW, by stage, for ARRs with paths that source inside or outside the zone where the load is located, for the 2025/2026 planning period. Table 13-4 shows that, for the 2025/2026 planning period, 78.6 percent of the ARR MW are based on generation inside the zone where the ARR load is located and 21.4 percent of the ARR MW are based on generation outside the zone where the ARR load is located. In contrast, only 15.5 percent of congestion resulted from constraints inside the zone where load is located and 84.5 percent of congestion resulted from constraints outside the zone where load is located during the 2024/2025 planning period (Table 13-55). This illustrates one of the fundamental issues with the path based approach which originated in a cost of service design where most load was served by generation in the same zone as load. In fact, in the PJM market, which operates as an integrated network, a significant proportion of congestion results from constraints that are not in the same zone as load. The path based approach cannot and does not reflect the actual congestion paid by load.

Table 13-4 Share of ARRs that source in/out of load zone: 2025/2026 planning period

	Stage 1A		Stage 1B		Stage 2		Total	
	Out of Zone	In Zone	Out of Zone	In Zone	Out of Zone	In Zone	Out of Zone	In Zone
ACEC	31.1%	36.3%	4.7%	9.3%	8.3%	10.3%	44.1%	55.9%
AEP	9.4%	55.8%	1.6%	20.6%	3.0%	9.6%	13.9%	86.1%
APS	9.4%	69.7%	0.9%	13.1%	1.2%	5.8%	11.5%	88.5%
ATSI	38.9%	47.8%	1.2%	2.9%	1.5%	7.7%	41.5%	58.5%
BGE	34.9%	48.5%	10.5%	0.0%	4.0%	2.1%	49.4%	50.6%
COMED	0.0%	64.2%	0.0%	8.7%	0.0%	27.2%	0.0%	100.0%
DAY	69.0%	8.7%	3.6%	7.3%	7.4%	4.1%	79.9%	20.1%
DOM	0.5%	94.1%	0.0%	0.9%	0.0%	4.5%	0.5%	99.5%
DPL	22.0%	64.5%	2.9%	1.3%	3.8%	5.5%	28.7%	71.3%
DUKE	48.4%	46.0%	0.8%	2.8%	0.6%	1.4%	49.8%	50.2%
DUQ	68.4%	4.1%	7.5%	0.4%	15.3%	4.3%	91.2%	8.8%
EKPC	48.7%	0.0%	38.4%	0.0%	12.5%	0.4%	99.6%	0.4%
EXT	22.7%	0.0%	0.0%	0.0%	77.3%	0.0%	100.0%	0.0%
JCPL	10.4%	26.8%	31.8%	0.5%	30.0%	0.5%	72.2%	27.8%
MEC	16.5%	53.1%	7.0%	0.5%	6.8%	16.2%	30.2%	69.8%
OVEC	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	100.0%	0.0%
PE	25.7%	42.3%	0.2%	5.0%	0.6%	26.1%	26.5%	73.5%
PECO	1.8%	93.4%	0.2%	1.0%	0.3%	3.4%	2.3%	97.7%
PEPCO	24.1%	60.8%	0.0%	11.8%	0.0%	3.3%	24.1%	75.9%
PPL	0.0%	62.6%	0.4%	5.7%	0.6%	30.7%	1.0%	99.0%
PSEG	22.4%	36.4%	24.5%	0.1%	6.6%	10.0%	53.5%	46.5%
REC	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	100.0%	0.0%
Total	14.8%	58.8%	3.9%	7.5%	2.7%	12.4%	21.4%	78.6%

Stage 1A Infeasibility

Stage 1A ARRs are allocated for a year, but guaranteed for 10 years, with the ability for a participant to opt out of any planning period within the 10 years. PJM conducts a simultaneous feasibility analysis to determine the transmission upgrades required to ensure that the long term ARRs can remain feasible. The rules provide that if a simultaneous feasibility test violation occurs in any year, PJM will identify or accelerate any transmission upgrades to resolve the violation and these upgrades will be recommended for inclusion in the PJM RTEP process. But such transmission upgrades must pass PJM's RTEP process.

PJM's transmission planning process (RTEP) does not identify a need for new transmission associated with Stage 1A overallocations because there is, in fact, no need for new transmission associated with Stage 1A ARRs. 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. This continues to be true even with the replacement of retired generating units.

For the 2024/2025 and 2025/2026 planning periods, Stage 1A of the Annual ARR Allocation was infeasible, resulting in an over allocation of ARRs on the affected facilities. As a result, modeled system capability, in excess of actual system capability, was provided to the Stage 1A ARRs and added to the FTR auction. According to Section 7.4.2 (i) of the OATT, the capability limits of the binding constraints rendering these ARRs infeasible must be increased in the model and these increased limits must be used in subsequent ARR and FTR allocations and auctions for the entire planning period, except in the case of extraordinary circumstances. Stage 1A related over allocations have to be made up elsewhere in PJM's FTR market model, in the form of reduced system capability, in order for PJM to achieve its goal of fully funding FTRs. The need for and use of these artificial and factually incorrect calculations are another illustration of the failure of the FTR/ARR design to meet basic logical standards.

Table 13-5 shows the MW quantity and count of overloaded constraint/contingency pairs and the reasons for the modeled overload for the 2024/2025 and 2025/2026 planning periods. In order to eliminate the infeasibilities for the requested Stage 1A ARR allocations, PJM needed to raise the modeled capacity limits above the actual transmission line limits on 113 constraint/contingency pairs, 84 of which were internal to PJM, a total of 25,565 MW in the 2025/2026 planning period. This is an increase of 15 constraint/contingency pairs (15.3 percent), an increase of 27 constraint/contingency pairs internal to PJM, (47.4 percent), and an increase of 8,691 MW (51.5 percent) compared to the 2024/2025 planning period.[22]

22 *PJM 2023/2024 Stage 1A Over allocation notice*, PJM FTRs, <https://pjm.com/-/media/markets-ops/ftr/annual-arr-allocation/2023-2024/2023-2024-stage-1a-over-allocation-notice.ashx> (March 6, 2023).

Table 13-5 Stage 1A overloaded constraint reasons and MW: 2024/2025 and 2025/2026 planning periods)

		2024/2025		2025/2026	
Reason	Type	MW	Count	MW	Count
Network Load	Internal PJM	2,745	5	17	1
Network Load	M2M Flowgate	2,003	26	2,177	23
Transmission Outage	Internal PJM	12,031	57	23,316	84
Transmission Outage	M2M Flowgate	95	10	55	5
Transmission Outage	Tie Line	0	0	0	0
Total		16,874	98	25,565	113

Table 13-6 shows the share of Stage 1A over allocations for the 2024/2025 and 2025/2026 planning periods for ARR allocations that source inside and outside the zone where the over allocated MW sink. The share of over allocations that has a source outside the zone in which it sinks, increased 3.4 percent from 26.8 percent in the 2024/2025 planning period to 27.7 percent in the 2025/2026 planning period. The total MW of overloaded constraint/contingency pairs (Table 13-5) is greater than the total MW of overloaded Stage 1A ARR paths (Table 13-6) because an individual overloaded ARR path can require the modeled capacity limit to be increased for multiple constraint/contingency pairs and multiple contingencies per constraint.

Table 13-6 Stage 1A overloaded paths that sink inside and outside source zone: 2024/2025 and 2025/2026 planning periods

	2024/2025 Planning Period				2025/2026 Planning Period			
	MW		Proportion		MW		Proportion	
	In Zone	Out of Zone	In Zone	Out of Zone	In Zone	Out of Zone	In Zone	Out of Zone
ACEC	0.0	0.1	0.0%	100.0%	0.0	0.0	NA	NA
AEP	2,779.5	692.9	80.0%	20.0%	2,644.9	489.6	84.4%	15.6%
APS	19.0	486.0	3.8%	96.2%	0.5	414.9	0.1%	99.9%
ATSI	1,327.2	1,840.3	41.9%	58.1%	1,640.3	2,030.8	44.7%	55.3%
BGE	0.0	972.3	0.0%	100.0%	0.0	300.7	0.0%	100.0%
COMED	3,222.5	0.0	100.0%	0.0%	1,586.5	0.0	100.0%	0.0%
DAY	0.0	234.9	0.0%	100.0%	0.0	255.3	0.0%	100.0%
DOM	8,481.8	3.7	100.0%	0.0%	7,053.2	7.6	99.9%	0.1%
DPL	166.0	107.1	60.8%	39.2%	384.4	156.7	71.0%	29.0%
DUKE	0.0	647.6	0.0%	100.0%	192.1	1,175.8	14.0%	86.0%
DUQ	0.0	178.9	0.0%	100.0%	0.0	133.7	0.0%	100.0%
EKPC	0.0	104.1	0.0%	100.0%	0.0	93.0	0.0%	100.0%
JCPL	0.0	0.0	NA	NA	0.0	0.0	NA	NA
MEC	19.5	10.9	64.1%	35.9%	0.0	0.0	NA	NA
PE	174.5	369.7	32.1%	67.9%	97.1	10.5	90.2%	9.8%
PECO	424.1	0.0	100.0%	0.0%	10.1	0.0	100.0%	0.0%
PEPCO	0.0	427.8	0.0%	100.0%	0.0	151.5	0.0%	100.0%
PPL	0.0	0.0	NA	NA	0.0	0.0	NA	NA
PSEG	0.0	0.0	NA	NA	0.0	0.0	NA	NA
TOTAL	16,614.1	6,076.3	73.2%	26.8%	13,609.1	5,220.1	72.3%	27.7%

Figure 13-1 shows the predicted and estimated impact of Stage 1A infeasibilities on FTR funding for the 2012/2013 through 2024/2025 planning periods, as well as the predicted impact on funding for the 2025/2026 planning period. The predicted funding is based on the infeasible ARR MW and the nodal price of the source and sink in the Annual FTR Auction. The estimated funding is calculated assuming every infeasible ARR MW is self scheduled, and uses the hourly congestion LMP values of the applicable day-ahead hours. The large estimated funding impact in the 2024/2025 planning period was a result of the relatively large overallocation of Stage 1A ARRs (and related FTRs) relative to expected congestion on Stage 1A related paths (see Figure 13-13).

Figure 13-1 Stage 1A Infeasibility funding impact

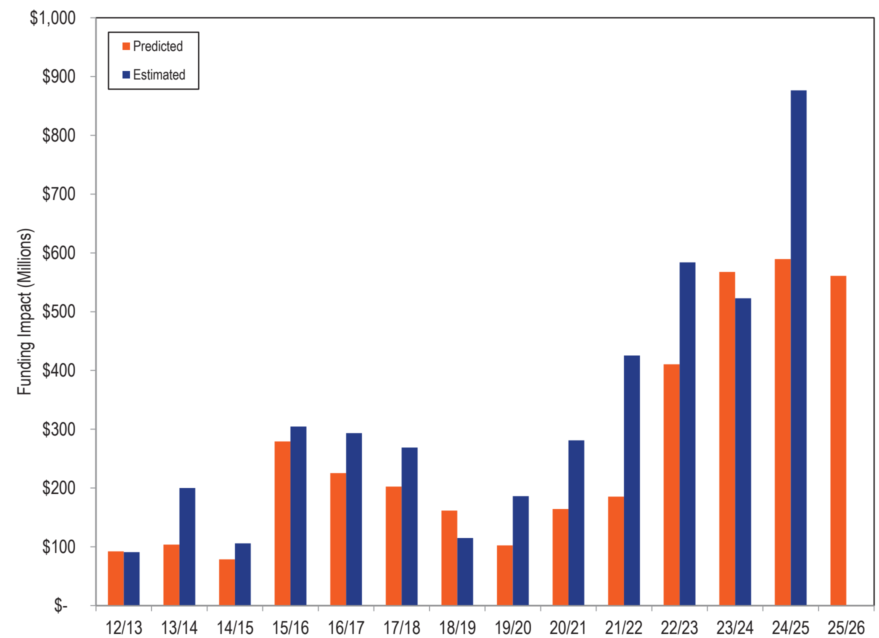


Table 13-7 shows the MW of retired generation sources for Stage 1A ARRs, the Qualified Replacement Resource (QRR) MW assigned by PJM for all resources and the replacement MW that were considered rate based. A rate based unit is a replacement generator that is owned by the ARR holder, or subject to firm energy and capacity supply contracts.[23] The term rate based is a misleading reference to the premarket cost of service regulation paradigm. If PJM does not find such a unit, PJM will use another unit that is close to where the retired unit was located even if it is not owned or under contract.

23 See "PJM Manual 6: Financial Transmission Rights," Rev. 34 (May 21, 2025) at 21.

Table 13-7 Qualified Replacement Resource (QRR) results: 2025/2026 planning period

Zone	Historical Retired	Replacement (All)	Replacement (Rate-based)
ACEC	1,779.8	1,056.5	59.0
AEP	8,330.2	7,776.4	1,839.7
APS	3,315.5	3,456.2	97.2
ATSI	7,154.3	4,642.1	36.7
BGE	1,360.0	867.0	0.0
COMED	8,503.8	6,423.1	4.5
DAY	2,416.5	263.4	6.4
DOM	5,996.6	6,380.1	5,333.9
DPL	976.7	445.6	218.3
DUKE	3,234.5	2,029.2	57.6
DUQ	1,301.0	811.7	0.0
EKPC	198.1	229.3	0.0
JCPL	2,137.1	1,373.2	0.0
OVEC	0.0	459.2	1,854.0
MEC	1,082.0	1,059.4	0.0
PE	1,606.5	1,570.3	0.1
PECO	1,432.3	1,077.0	0.0
PEPCO	3,726.0	2,030.3	0.0
PPL	1,224.3	779.6	0.0
PSEG	5,093.2	3,177.0	0.0
REC	0.0	0.0	0.0
Total	60,868.5	45,906.6	9,507.4

ARR Reassignment for Retail Load Switching

PJM rules provide that when load switches between LSEs during the planning period, an LSE gaining load in the same control zone is allocated a proportional share of positively valued ARRs and residual ARRs within the control zone based on the shifted load.[24] ARRs are reassigned to the nearest 0.001 MW and may be reassigned multiple times over a planning period. The reassignment of positively valued ARRs supports competition by ensuring that the offset to congestion follows load, thereby removing a barrier to competition among LSEs and, by ensuring that only ARRs with a positive value are reassigned, preventing an LSE from assigning poor ARR choices to other LSEs. However, when ARRs are self scheduled as FTRs, the self scheduled FTRs do not follow load that shifts while the ARRs do follow load that shifts, and this may result in lower value of the ARRs for the receiving LSE compared to the total value held by the original ARR holder.

Table 13-8 summarizes ARR MW and associated revenue reassigned for network load in each control zone where changes occurred from June 1, 2024, through March 31, 2026.

There were 31,342 MW of ARRs associated with $1.6 million of revenue that were reassigned for the first ten months of the 2025/2026 planning period. There were 27,940 MW of ARRs associated with $0.9 million of revenue that were reassigned in the same period of the 2024/2025 planning period and 32,594 MW of ARRs associated with $1.2 million of revenue that were reassigned for the entire 2024/2025 planning period.

24 See "PJM Manual 6: Financial Transmission Rights," Rev. 34 (May 21, 2025).

Table 13-8 ARRs and ARR revenue automatically reassigned for network load changes by control zone: June 2024 through March 2026

	ARRs Reassigned (MW-day)		ARR Revenue Reassigned [Dollars (Thousands) per MW-day]	
Control Zone	2024/2025 (12 months)	2025/2026 (10 months)	2024/2025 (12 months)	2025/2026 (10 months)
ACEC	300	325	$4.2	$2.4
AEP	3,427	2,474	$64.9	$38.5
APS	1,666	1,706	$75.8	$92.1
ATSI	4,572	3,990	$161.5	$109.6
BGE	2,408	3,205	$341.1	$657.2
COMED	2,975	2,046	$30.0	$40.8
DAY	1,298	1,304	$20.5	$23.1
DOM	288	221	$15.1	$14.6
DPL	689	757	$67.9	$90.8
DUKE	1,824	2,139	$106.6	$68.3
DUQ	1,437	1,408	$20.0	$12.3
EKPC	0	0	$0.0	$0.0
JCPLC	907	993	$11.4	$13.9
MEC	750	775	$30.1	$18.4
OVEC	0	0	$0.0	$0.0
PE	749	676	$42.2	$55.1
PECO	3,020	2,956	$32.7	$33.2
PEPCO	2,320	2,113	$61.1	$152.4
PPL	2,948	3,445	$66.5	$111.0
PSEG	865	713	$21.4	$21.7
REC	151	96	$2.7	$2.5
Total	32,594	31,342	$1,175.6	$1,557.9

Revenue

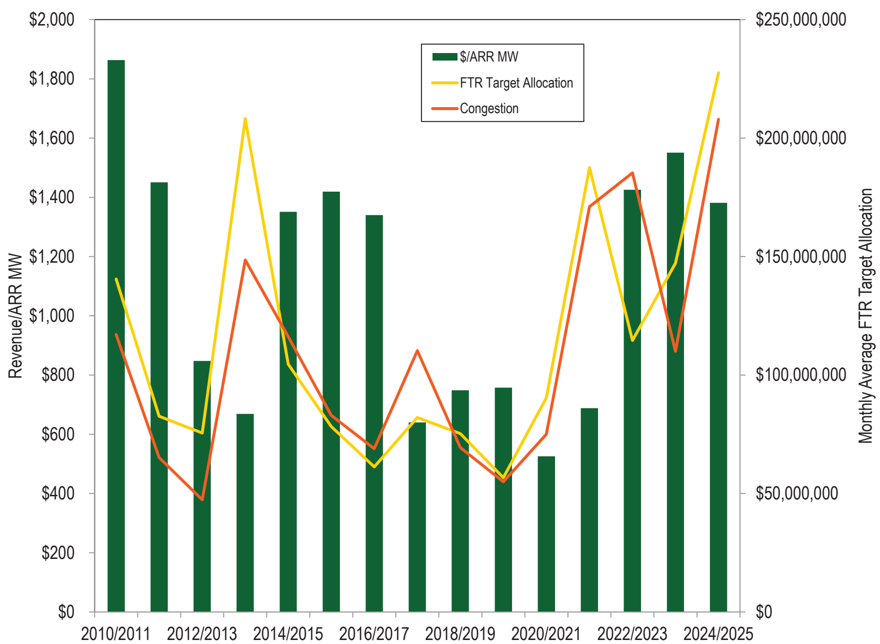
ARRs are allocated to qualifying customers rather than sold, so ARR revenue (target allocation) is different from the revenue that results from the FTR auctions, which generally exceeds the sum of the ARR target allocations.

Figure 13-2 shows the revenue per ARR MW held for each month of the 2010/2011 planning period through the 2024/2025 planning period. The revenue per ARR MW held does not include target allocation related payouts for self scheduled FTRs or surplus revenue, but does include Residual ARRs starting in August 2012.

PJM has 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. FTR prices increased in the 2014/2015 Annual FTR Auction in part as a result of reduced supply caused by PJM's assumption of more outages in the model relative to prior years. The decrease in system capability caused by PJM's more conservative modeling of the FTR market model reduced Stage 1B and Stage 2 ARR allocations. The increased FTR prices resulted in an increase in revenue per ARR MW, but there are fewer ARR MW. For the 2014/2015 planning period, the total dollars per MW of ARR allocation was $11,279, while the previous planning period resulted in revenue per MW of $6,692, a 68.5 percent increase in revenue per allocated ARR MW. Some of the ARR MW lost from proration were provided in the Residual ARR process, but the residual allocations are not comparable to the ARRs awarded in the annual process because residual ARR allocations change each month and cannot be self scheduled as FTRs. For the 2015/2016 and 2016/2017 planning periods, the revenue per MW of ARR allocation was $10,642 and $10,411. During these planning periods PJM chose more restrictive modeling criteria, which did not release the full capacity of the FTR model to account for revenue inadequacies. Beginning in the 2017/2018 planning period, when balancing congestion was removed from FTR funding, PJM reinstated less restrictive modeling criteria, and the revenue per MW of ARR decreased due to an increase in modeled capability. For the 2017/2018 and 2018/2019 planning periods the revenue per MW of ARR was $5,168 and $6,841. For the 2022/2023 planning period, cleared ARR MW decreased significantly (see Table 13-3) from the previous planning period, indicating that PJM again chose more restrictive modeling criteria for the FTR model to improve FTR funding. This results in fewer ARRs being awarded. Due to significant increases in FTR prices in the 2022/2023 planning period, the revenue per MW of ARR was $12,274. For the 2023/2024 planning period, FTR prices decreased compared to the 2022/2023 planning period and the revenue per MW of ARR was $14,463, a 17.8 percent decrease. For the 2024/2025 planning period PJM again used less restrictive modeling criteria in the FTR model, resulting in more ARRs being awarded. The revenue per MW of ARR decreased to $12,058, a 16.6 percent decrease.

Under the current rules, load is required to directly pay balancing congestion costs, not included in Figure 13-2, which reduce the revenue received by ARR holders. There is no support for the assertion made by proponents of shifting balancing congestion to load that higher ARR values would result, and there is no evidence of any kind that load is better off as a result of the arbitrary assignment of balancing congestion to load.

Figure 13-2 Revenue per ARR MW paid to ARR holders compared to congestion and FTR target allocations: 2010/2011 through 2024/2025 planning periods



ARR holders have limited options to pick source points for their ARRs. The holders of Stage 1A rights are limited to specific historical sources (or PJM defined replacement sources when resources retire). Of the stage 1A rights allocated to ARR holders, 58.5 percent were sourced within the ARR holder's zone in the 2024/2025 planning period. Table 13-4 shows that, for the 2025/2026 planning period, 70.6 percent of the ARR MW are based on generation inside the zone where the ARR load is located and 29.4 percent of the ARR MW are based on generation outside the zone where the ARR load is located. In contrast, only 15.5 percent of congestion resulted from constraints inside the zone where load is located and 84.5 percent of congestion resulted from constraints outside the zone where load is located during the 2024/2025 planning period. The primary source of a load zone's actual congestion is the result of transmission constraints that separate that zone from resources external to that zone, not by constraints internal to that zone. The congestion offset revenues per MW of internally sourced Stage 1A ARR rights are less than the revenue per MW of Stage 1A ARR rights from externally sourced resources. Table 13-9 shows the share of ARR revenue, by stage, for ARRs with paths that source inside or outside the zone where the load is located, for the 2025/2026 planning period. While 14.8 percent of all ARR MW are Stage 1A ARRs with sources outside the zone where load is located (see Table 13-4), those ARRs provide 26.2 percent of the total ARR revenues.

This illustrates one of the fundamental issues with the path based approach which originated in a cost of service design where most load was served by, or assumed to be served by, generation in the same zone as load. In fact, in the PJM market, which operates as an integrated network, a significant proportion of congestion is based on constraints that are not in the same zone as load. The path based approach does not and cannot reflect the actual congestion paid by load. The use of the path based approach is the fundamental source of the under assignment of congestion revenue rights to load in the ARR/FTR model.

Table 13-9 Share of ARR revenue that sources in/out of load zone: 2025/2026 planning period

	Stage 1A		Stage 1B		Stage 2		Total	
	Out of Zone	In Zone	Out of Zone	In Zone	Out of Zone	In Zone	Out of Zone	In Zone
ACEC	39.2%	33.5%	3.2%	0.2%	13.7%	10.1%	56.1%	43.9%
AEP	17.9%	52.8%	0.6%	18.0%	6.0%	4.7%	24.5%	75.5%
APS	18.8%	66.7%	0.6%	9.8%	0.5%	3.6%	19.9%	80.1%
ATSI	63.8%	25.8%	0.2%	0.3%	1.2%	8.7%	65.2%	34.8%
BGE	81.9%	13.8%	2.8%	0.0%	0.9%	0.6%	85.6%	14.4%
COMED	0.0%	50.6%	0.0%	4.1%	(0.0%)	45.4%	(0.0%)	100.0%
DAY	78.1%	1.4%	4.1%	1.2%	11.6%	3.6%	93.8%	6.2%
DOM	0.7%	97.7%	0.0%	0.5%	0.0%	1.0%	0.7%	99.3%
DPL	26.3%	64.2%	1.8%	0.7%	1.3%	5.8%	29.3%	70.7%
DUKE	89.4%	9.3%	0.3%	0.5%	0.2%	0.2%	90.0%	10.0%
DUQ	87.1%	0.1%	0.8%	0.0%	11.1%	0.9%	99.0%	1.0%
EKPC	79.9%	0.0%	15.2%	0.0%	4.9%	0.0%	100.0%	0.0%
EXT	46.3%	0.0%	0.0%	0.0%	53.7%	0.0%	100.0%	0.0%
JCPL	15.1%	1.0%	19.7%	(0.0%)	64.0%	0.2%	98.8%	1.2%
MEC	11.3%	42.9%	5.1%	0.2%	6.9%	33.6%	23.3%	76.7%
OVEC	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	100.0%	0.0%
PE	20.8%	48.1%	0.0%	1.1%	0.3%	29.6%	21.1%	78.9%
PECO	(0.5%)	100.2%	(0.5%)	0.2%	0.5%	0.0%	(0.5%)	100.5%
PEPCO	89.3%	9.7%	0.0%	0.7%	0.0%	0.2%	89.3%	10.7%
PPL	(0.0%)	62.4%	(0.2%)	(0.4%)	1.8%	36.4%	1.5%	98.5%
PSEG	28.0%	51.4%	11.0%	0.1%	2.6%	7.0%	41.5%	58.5%
REC	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	100.0%	0.0%

ARR Target Allocations

Table 13-10 shows the monthly ARR target allocations from Annual ARRs and Residual Residual ARRs for the first ten months of the 2025/2026 planning period and the entire 2024/2025 planning period. Table 13-10 also shows the FTR auction revenue available to fund ARR target allocations. Annual ARR target allocations (Table 13-10) are based on the nodal clearing prices from FTR obligations in the Annual FTR Auction times the MW of the ARR. The annual ARR target allocation is divided evenly among every day of the planning period. Residual ARR target allocations (Table 13-10) are based on the nodal clearing prices from FTR obligations in the monthly FTR auctions and vary each month.

In the first ten months of the 2025/2026 planning period, total ARR target allocations (the sum of annual and residual ARR target allocations) were $1,605.5 million, up 31.2 percent from $1,223.4 million in the same period of the 2024/2025 planning period. Total ARR target allocations in the first ten months of the 2025/2026 planning period include $1,529.6 million annual ARR target allocations (up 23.7 percent relative the same period of the 2024/2025 planning period) and $76.0 million Residual ARR target allocations (up 243.9 percent relative to the same period of the 2024/2025 planning period). In the first ten months of the 2025/2026 planning period FTR auction revenue available to pay ARR target allocations was $1,777.3 million, up 28.0 percent from $1,383.0 million in the same period of the 2024/2025 planning period. The significant and unprecedented increase in Residual ARR target allocations compared to Annual ARR target allocations and FTR Auction Revenue led to the first month with an ARR deficiency in the history of the ARR market. In July 2025 there was a $229,526 deficiency for ARR holders. PJM's monthly auction process does not consider the impact of Residual ARR target allocation when the Monthly FTR Auctions are optimized and cleared.

Table 13-10 Monthly ARR target allocations compared to FTR auction revenue: 2024/2025 and 2025/2026 planning periods

Month	Annual ARR Target Allocations	Residual ARR Target Allocations	Total ARR Target Allocations	FTR Auction Revenue	ARR Surplus or Deficiency
Jun-24	$118,548,955	$1,542,269	$120,091,225	$133,459,438	$13,368,213
Jul-24	$122,500,587	$817,746	$123,318,333	$139,272,100	$15,953,768
Aug-24	$122,500,587	$2,192,686	$124,693,273	$140,450,805	$15,757,532
Sep-24	$118,548,955	$940,983	$119,489,938	$135,797,655	$16,307,717
Oct-24	$122,500,587	$675,276	$123,175,863	$142,077,688	$18,901,826
Nov-24	$118,548,955	$389,592	$118,938,547	$137,582,288	$18,643,741
Dec-24	$122,500,587	$1,423,964	$123,924,551	$142,273,691	$18,349,140
Jan-25	$122,500,587	$3,351,831	$125,852,418	$141,776,870	$15,924,451
Feb-25	$110,645,692	$9,503,030	$120,148,721	$128,790,514	$8,641,793
Mar-25	$122,500,587	$1,258,883	$123,759,470	$141,476,041	$17,716,571
Apr-25	$118,548,955	$3,845,490	$122,394,445	$138,463,040	$16,068,595
May-25	$122,500,587	$367,497	$122,868,084	$143,447,210	$20,579,127
Summary For Planning Period 2024/2025					
Total	$1,442,345,621	$26,309,246	$1,468,654,867	$1,664,867,340	$196,212,473
Jun-25	$150,943,224	$12,903,832	$163,847,056	$170,292,924	$6,445,867
Jul-25	$155,974,665	$23,175,461	$179,150,126	$178,920,600	($229,526)
Aug-25	$155,974,665	$13,502,528	$169,477,193	$179,519,198	$10,042,005
Sep-25	$150,943,224	$952,098	$151,895,322	$174,046,010	$22,150,688
Oct-25	$155,974,665	$4,658,518	$160,633,183	$179,868,836	$19,235,654
Nov-25	$150,943,224	$5,780,545	$156,723,769	$173,946,507	$17,222,738
Dec-25	$155,974,665	$1,556,605	$157,531,270	$176,753,225	$19,221,956
Jan-26	$155,974,665	$6,173,623	$162,148,288	$180,118,776	$17,970,489
Feb-26	$140,880,342	$2,951,786	$143,832,128	$169,142,110	$25,309,981
Mar-26	$155,974,665	$4,313,687	$160,288,352	$194,725,363	$34,437,011
Summary For Planning Period 2025/2026*					
Total	$1,529,558,002	$75,968,684	$1,605,526,686	$1,777,333,549	$171,806,863

*First ten months of the 2025/2026 planning period

Residual ARRs

Introduced August 1, 2012, Residual ARRs are available for eligible ARR holders when a transmission outage was modeled in the Annual ARR Allocation, but the transmission facility returns to service during the planning period. Residual ARRs can only be allocated to participants whose ARRs were prorated in Stage 1B and only to a maximum of the prorated reduction, so not all available Residual ARRs are allocated. Residual ARRs are automatically assigned to eligible participants the month before the effective date, are effective for a single month and cannot be self scheduled. Residual ARR target allocations are based on the clearing prices from FTR obligations for FTRs of the same period purchased in the relevant monthly auctions, may not exceed zonal network services peak load or firm transmission reservation levels and are only available up to the prorated ARR MW capacity as allocated in the Annual ARR Allocation. For the following planning period, these Residual ARRs are available as ARRs in the annual ARR allocation. Residual ARRs are a separate product from incremental ARRs. Beginning with the June 2017 monthly auction, Residual ARRs that would have cleared with a negative target allocation are not assigned to participants.[25] In prior planning periods, PJM's modeling of excess outages in order to manage FTR market outcomes resulted in the allocation of some ARRs that would have been allocated in Stage 1B being allocated as Residual ARRs on a month to month basis without the option to self schedule.

Table 13-11 shows the Residual ARRs allocated to participants and the associated target allocations. The available volume is the total additional capacity available to be allocated as Residual ARRs. The cleared volume is the residual ARR capacity actually allocated to participants with prorated ARRs based on the level of prorated ARRs in Stage 1B and the affected paths. In the first ten months of the 2025/2026 planning period, PJM allocated a total of 25,401.9 MW of Residual ARRs with a target allocation of $76.0 million. In the same period of the 2024/2025 planning period, PJM allocated a total of 28,034.1 MW of residual ARRs with a target allocation of $22.1 million. The 243.9 percent increase in target allocations for Residual ARRs without a corresponding increase in monthly FTR auction revenue (See Table 13-45) in the first ten months of the 2025/2026 planning period led to the ARR deficiency in July 2025.

25 See FERC Letter Order, Docket No. ER17-1057 (April 5, 2017).

Table 13-11 Residual ARR allocation volume and target allocation: 2014/2015 planning period through 2025/2026 planning period

Planning Period	Available Volume (MW)	Cleared Volume (MW)	Cleared Volume	Target Allocation
2014/2015	65,095.3	22,532.9	34.6%	$8,160,918.27
2015/2016	61,807.0	37,042.4	59.9%	$8,620,353.27
2016/2017	71,000.7	35,034.9	49.3%	$6,986,723.44
2017/2018	81,040.8	39,597.4	48.9%	$17,497,625.78
2018/2019	49,646.9	27,335.6	55.1%	$11,817,002.00
2019/2020	48,286.5	27,233.2	56.4%	$12,369,580.58
2020/2021	43,484.2	25,028.0	57.6%	$11,677,033.36
2021/2022	46,092.0	27,619.2	59.9%	$18,806,123.46
2022/2023	71,068.9	34,502.8	48.5%	$38,140,961.08
2023/2024	81,055.2	27,055.0	33.4%	$8,721,412.56
2024/2025	128,523.3	36,097.6	28.1%	$26,309,245.50
2025/2026*	104,226.2	25,401.9	24.4%	$75,968,684.34

*First ten months of 2025/2026 planning period

IARRs

In theory, Incremental Auction Revenue Rights (IARRs) are ARRs made available by physical transmission system upgrades from customer funded transmission projects or from merchant transmission or generation interconnection requests. In order for a transmission project to result in IARRs, the project must create simultaneously feasible incremental market flow capability in PJM's ARR market model, over and above all system capability being used by existing allocated ARRs and/or would be used by granting any prorated outstanding ARR requests, in the ARR market model.[26]

There are three sources of IARRs: IARRs based on a specific transmission investment; IARRs based on merchant transmission or generation interconnection projects; and IARRs based on RTEP upgrades. In the case of a specific transmission investment, the participant elects desired IARR MW between a specified source and sink and PJM and the affected transmission owners determine the upgrades necessary to create incremental capability.[27] In the other two cases, the participants paying for the upgrades are assigned IARRs if any are created. IARR requests have resulted in 12 unique source and sink combinations, totaling 1,887.2 MW of IARR paths.

The MMU supports increased competition to provide transmission using market mechanisms. The IARR process is not a viable mechanism for facilitating competitive transmission investments. Maintaining the IARR process impedes the search for real solutions. PJM's process for creating and assigning IARRs is fundamentally flawed and cannot be made consistent with the requirements of Order No. 681 which established IARRs.[28]

Order No. 681 requires that long-term firm transmission rights made feasible by transmission upgrades or expansions be available upon request to the party that pays for such upgrades or expansions.[29] Order No. 681 also requires that the rights granted by upgrades/expansions cannot come at the expense of transmission rights held by others. IARRs are treated as Stage 1A rights, which are given first and absolute priority in PJM's annual allocation process. Granting Stage 1A status to IARRs is preferential treatment of IARR rights relative to the ARR rights belonging to load. If the annual market model used to assign existing ARR rights in a given year cannot simultaneously support all Stage 1A ARR requests, the system model is modified so as to make the Stage 1A ARR requests feasible. The result is an over allocation of congestion rights relative to expected congestion. To avoid having FTR target allocations exceed expected congestion, PJM reduces the annual supply (market model system capability) available to non-Stage 1A rights through selective line outages and line rating reductions. The resulting market model artificially supports all the Stage 1A ARR requests and artificially reduces the amount of remaining later tier ARRs from other rights holders. Stage 1A ARRs, including IARRs, are approved at the expense of other preexisting congestion rights. In the case of IARRs, this is in violation of Order No. 681.

The MMU recommends that IARRs be eliminated from the PJM tariff. If IARRs are not eliminated, the MMU recommends that IARRs be subject to prorating like all other ARR rights rather than being exempt from prorating.

26 See PJM Incremental Auction Revenue Rights Model Development and Analysis, PJM June 12, 2017. <https://www.pjm.com/~/media/markets-ops/ftr/pjm-iarr-model-development-and-analysis.ashx>.
27 See PJM OATT. Attachment EE <https://www.pjm.com/directory/merged-tariffs/oatt.pdf>.
28 See November 7, 2019 Comments on TranSource, LLC v. PJM, 168 FERC ¶ 61,119 (2019) ("Opinion No. 566").
29 *Long-Term Firm Transmission Rights in Organized Electricity Markets*, Order No. 681, 116 FERC ¶ 61,077 (2006) ("Order No. 681"), *order on reh'g*, Order No. 618-A, 117 FERC ¶ 61,201 (2006), *order on reh'g*, Order No. 681-A, 126 FERC ¶ 61,254 (2009).

Financial Transmission Rights

FTRs are financial instruments that entitle their holders to receive revenue or require them to pay charges based on locational congestion price differences in the day-ahead energy market across specific FTR transmission paths. These day-ahead congestion price differences (shadow prices), multiplied by the FTR position in MW, are termed the FTR target allocations. The FTR target allocations define the maximum, but not guaranteed, payout for FTRs. The target allocation of an FTR reflects the difference in day-ahead congestion prices (CLMPs) rather than the difference in LMPs, which includes both congestion and marginal losses. Negative target allocations require the FTR holder to make payments rather than receive revenues in the FTR market. One of the fundamental flaws in the FTR design is the mismatch between congestion and the differences in day-ahead prices between nodes. The difference in day-ahead congestion prices is not congestion. Target allocations are not congestion. It is this fundamental flaw that creates what PJM refers to as "underfunding" or "revenue inadequacy." If FTRs were the rights to congestion revenue, there could never be revenue inadequacy. Congestion payments to FTR holders would always exactly equal congestion revenues.

Under the current rules, the revenue available to pay FTR holders' target allocations in a given month includes day-ahead congestion, payments by holders of negatively valued FTRs, and FTR auction revenues greater than ARR target allocations. Any such revenue above FTR target allocations from prior months in a planning period are used to pay any current month shortfalls. Payments to FTR holders for each planning period cannot exceed the target allocations because the target allocations define the FTR product purchased. At the end of each planning period, any surplus revenue above the target allocations is distributed to ARR holders.

FTR funding is not on a path specific basis or on an hour to hour basis and treats all FTRs the same. For example, if the payout ratio is less than 1.0 at the end of the planning period, the payments to all FTRs are reduced. Payments are made pro rata based on target allocations. The result is widespread cross subsidies because assignment of path specific FTRs may exceed system capability and affect the payments to FTRs on other paths. FTR auction revenues and excess revenues are carried forward from prior months and distributed back from later months within a planning period. At the end of a planning period, if the total revenue is less than the total target allocations, an uplift charge is collected from any FTR market participants that hold FTRs for the planning period, based on their pro rata share of total net positive FTR target allocations, excluding any charge to FTR holders with a net negative FTR position for the planning period.

Auction market participants may offer to buy FTRs between any eligible pricing nodes on the system, as defined by PJM for each auction. For the Annual FTR Auction and FTRs bought in the monthly auctions, the available FTR source and sink points include hubs, control zones, aggregates, generator buses, load buses and interface pricing points. For the Long Term FTR Auction there is a smaller set of available hubs, control zones, aggregates, generator buses and interface pricing points available. PJM does not allow FTR buy bids to clear with a price of zero unless there is at least one constraint in the auction which affects the FTR path. FTRs are available to the nearest 0.1 MW.

FTRs are bought from supply defined by PJM. The fact that load is selling congestion revenue rights is not recognized in the FTR design, although FTR buyers can resell FTRs at a price they agree to accept. Load has no role in defining the price at which PJM sells FTRs on their behalf. Load has no role in deciding the total FTR MW to be sold. Load has no role in deciding whether to sell load's rights to congestion revenues. PJM's objective in the FTR auctions is to maximize auction revenue, based only on the total set of bid prices and bid MW, but absent reservation prices from load. The failure to allow sellers the ability to decide at what price to sell FTRs is a fundamental flaw in the FTR market. The result is that PJM cannot actually maximize auction net revenue and that the FTR market is not really a market.

Once bought from PJM, FTRs can be bought and sold. Buy bids are bids to buy FTRs in the auctions. Sell offers are offers to sell existing FTRs in the auctions.

Market participants can buy and sell existing FTRs, outside of the auction process, through a voluntary bulletin board, termed the PJM bilateral market. FTRs can also be exchanged bilaterally without using the bulletin board.

Prior to June 30, 2024, there was no requirement to report accurate detailed information about bilateral transactions settled through PJM billing systems. Effective June 30, 2024, the Commission accepted PJM's proposed revisions to the rules that required the reporting of bilateral price information and corroborating contract documents of any bilateral change of FTR ownership between participants/accounts that is settled through PJM settlement systems.[30] Bilateral transactions remain dependent on the contract established between the parties. PJM has no knowledge of bilateral transactions, or the terms and risks of bilateral transactions, that are done outside of PJM's bilateral market system.

Supply and Demand

Total FTR supply in each auction as defined by PJM is limited by the definition of the transmission system capacity included in the PJM FTR market model as modified, for example, by PJM assumptions about transmission outages, for which there are no clear rules. PJM may also limit available transmission capacity through subjective judgment exercised without any clear guidelines.

The FTR auction process does not account for the fact that significant transmission outages, which have not been provided to PJM by transmission owners prior to the auction date, will occur during the periods covered by the auctions. Such transmission outages may or may not be planned in advance or may be emergency outages.[31] In addition, it is difficult to model in an annual auction two outages of similar significance and similar duration in different areas which do not overlap in time. The choice of which to model will generally have significant distributional consequences; they will affect different areas very differently. The fact that outages are modeled at significantly lower than historical levels results in selling too much FTR capacity, which creates downward pressure on ARR prices. To address this issue within the existing design, the MMU recommends that PJM use probabilistic outage modeling to better align the supply of ARRs and FTRs with actual expected transmission capacity.

30 *See* 187 FERC ¶ 61,020.
31 See the *2022 Annual State of the Market Report for PJM*, Volume 2, Section 12: Transmission Facility Outages: Transmission Facility Outages Analysis for the FTR Market.

Long Term FTR Auctions

In July 2006, FERC approved Order No. 681 mandating the creation of long term firm transmission rights in transmission organizations with organized electricity markets. FERC's goal was that "load serving entities be able to request and obtain transmission rights up to a reasonable amount on a long-term firm basis, instead of being limited to obtaining exclusively annual rights."[32] Despite that order and inconsistent with the directive in that order, LSEs are not able to request ARRs nor are LSEs guaranteed rights to the revenue from Long Term FTR Auctions in PJM's long term FTR auction market design. Excess system capability in years two and three of the long term FTR auction is never made available to load in the form of ARRs and is only made available to FTR buyers.

PJM conducts the Long Term FTR Auction for the next three consecutive planning periods. The Long Term FTR Auction consists of five rounds beginning in June of the preceding planning period and continuing through March. FTRs purchased in prior rounds or Long Term Auctions may be offered for sale in subsequent rounds of the long term, annual or monthly FTR auctions. FTRs obtained in the Long Term FTR Auctions have terms of one year. FTR products available in the Long Term Auction include 24 hour, on peak and off peak FTR obligations, with FTR options unavailable in the Long Term FTR Auctions.

Beginning with Round 2 of the 2019/2022 Long Term FTR Auction, PJM implemented revisions to the determination of residual system capability made available in the Long Term FTR Auctions, and eliminated the YRALL product, consistent with the MMU's recommendation. The revisions affect the determination of ARR rights reserved for ARR holders. Rather than simply preserving the ARR cleared capacity from the previous annual allocation, PJM reruns the simultaneous feasibility test for the ARR/FTR market model, without outages, using the previous year's ARR requests, prorated when necessary, and uses the resulting ARRs as the basis for reserving capability for ARR holders in the Long Term FTR Auction. The ARR requests are greater than the previously cleared ARRs. The difference between the requested ARRs and the ARR/FTR market model's transmission system capacity, both without outages,

32 Order No. 681 at P 17.

determines the residual capability offered in the Long Term FTR Auction. The revisions provide ARR holders with more congestion rights in the Long Term FTR Auction that will carry into the Annual FTR Auction.

But the revisions do not address the congestion revenue rights sold in years two and three of the Long Term FTR Auction, which remain unavailable to ARRs. As a result, the rights to significant congestion revenues are still assigned to the Long Term FTR Auction without ever having been made available to ARR holders. That outcome is inconsistent with the basic logic of ARRs and inconsistent with the stated intent of the market design which is to return all congestion revenues to load.

Long Term FTR Auction transmission capacity is determined by removing all outages and running an offline model of the previous Annual FTR Auction model with all ARR bids from the prior annual ARR allocation. Any ARR MW that clear in this offline model are reserved for ARR holders in the relevant planning periods, and are removed from the Long Term FTR Auction capability. Even this approach does not, and cannot, preserve all congestion revenues for ARR holders in the first year of the Long Term Auction due to changes in system topology and outage selection between planning periods. PJM outage assumptions are a key factor in determining the supply of ARRs and the related supply of FTRs in the Annual FTR Auction.

Annual FTR Auctions

Annual FTRs are effective for an entire planning period, June 1 through May 31. Outages expected to last two or more months, as well as any outages of a shorter duration that PJM decides would cause FTR revenue inadequacy if not modeled, are included in the determination of the simultaneous feasibility for the Annual FTR Auction.[33] While the full list of outages selected is publicly posted, PJM exercises significant subjective judgment in selecting outages to accomplish FTR revenue adequacy goals and the process by which these outages are selected is not clear, is not defined and is not documented. ARR holders who wish to self schedule must inform PJM prior to round one of the annual auction. Any self scheduled ARR requests clear 25 percent of the requested volume in each round of the Annual FTR Auction as price takers.

33 See "PJM Manual 6: Financial Transmission Rights," Rev. 34 (May 21, 2025).

The Annual FTR Auction consists of four rounds that allow any PJM member to bid for any FTR or to offer for sale any FTR that they currently hold. FTRs in the auctions include obligations and options and 24 hour, peak, off peak, and weekend peak products. FTRs purchased in one round of the Annual FTR Auction can be sold in later rounds or in the Monthly Balance of Planning Period FTR Auctions.

Monthly Balance of Planning Period FTR Auctions

Total Monthly FTR Auction capacity is based on the residual capacity available after the Long Term and Annual FTR auctions are conducted and adjustments are made to outages to reflect anticipated system conditions for the time periods auctioned. Outages expected to last five or more days are included in the determination of the simultaneous feasibility test for the Monthly Balance of Planning Period FTR Auction. These are single round monthly auctions that allow any transmission service customer or PJM member to bid for any FTR or to offer for sale any FTR that they currently hold. Beginning with the 2020/2021 planning period, market participants can bid for or offer monthly FTRs for any of the remaining individual calendar months in the planning period. FTRs in the auctions include obligations and options and 24 hour, peak, off peak, and weekend peak products.[34]

Bilateral Market

Market participants can buy and sell existing FTRs, outside of the auction process, through a voluntary bulletin board, termed the PJM bilateral market. FTRs can also be exchanged bilaterally without using the bulletin board. Bilateral transactions that are not done through PJM can involve parties that are not PJM members. PJM has no knowledge of bilateral transactions, or the terms and risks of bilateral transactions, that are done outside of PJM's bilateral market system. Prior to June 30, 2024, there was no requirement to report accurate detailed information about bilateral transactions settled through PJM billing systems. Effective June 30, 2024, the Commission accepted PJM's proposed revisions to the rules that required the reporting of bilateral price information and corroborating contract documents of any bilateral change of FTR ownership between participants/accounts that

34 See "PJM Manual 6: Financial Transmission Rights," Rev. 34 (May 21, 2025).

is settled through PJM settlement systems.[35] Bilateral transactions remain dependent on the contract established between the parties.

For bilateral trades reported to PJM, the FTR transmission path must remain the same, FTR obligations must remain obligations, and FTR options must remain options. However, an individual FTR may be split up into multiple, smaller FTRs, down to increments of 0.1 MW. Bilateral FTRs reported to PJM can also include more restrictive start and end times, meaning that the start time cannot be earlier than the original FTR start time and the end time cannot be later than the original FTR end time. Once the bilateral transaction is reported to PJM, PJM transfers ownership and adjusts credit requirements accordingly. Participants have used bilateral trades reported to PJM to reduce their credit requirements.

PJM's revised rules related to bilateral contracts fail to address the impact of PJM's indemnification rules. PJM stated that the "maintenance of the assumption of risk and costs is not a continuing interest in the FTR once sold; a continuing interest would be a right or benefit with respect to the subject FTR that survives the bilateral transaction." Contrary to logic, PJM asserts that only positive interests count as interests. Assumption of risks and costs of an FTR is, by definition, assumption of a financial interest in an FTR. When a participant buys an FTR in an auction, they assume the risks and costs of the FTR. Under PJM's indemnification rules the participant that bilaterally trades an FTR retains risks and costs associated with that FTR. Under PJM's indemnification rules, a bilateral seller of an FTR therefore has a continuing direct financial interest in that FTR and a direct financial interest in the credit and collateral of the buyer.

PJM's FTR market is the most transparent of all PJM markets. The facilitation of confidential bilateral transactions undercuts that transparency and therefore the efficiency of the FTR market. The bilateral information would be provided solely to PJM and not to the market. Transparency for PJM alone is not market transparency. The facilitation of confidential bilateral transactions does nothing to advance or improve the basic function of FTR markets.

35 *See* 187 FERC ¶ 61,020.

There is no reason to continue to permit bilateral transactions outside the PJM FTR market. The MMU recommends that the bilateral FTR transactions market be eliminated and that all FTR transactions should take place in the FTR auctions, in order to provide full transparency, effective price discovery, and to minimize risk to market participants and PJM members.[36] The bilateral FTR market provides a PJM facilitated mechanism that undermines transparency for market participants and for loads whose congestion revenues fund FTRs. Bilateral FTR trading outside of PJM's transparent FTR market is inefficient, inconsistent with the basic structure and purpose of the PJM FTR market, and creates unnecessary credit risk.

Market Structure

In order to evaluate the ownership of FTRs, the MMU categorizes all participants owning FTRs in PJM as either physical or financial. The MMU modified the method for categorizing participants as physical and financial participants. Prior to the *2025 Quarterly State of the Market Report for PJM: January through March,* participants were defined as either physical or financial at an organization level. Under the modified approach, physical entities are defined as individual accounts in PJM's settlement systems that take physical positions in PJM markets and typically include utilities and customers. Financial entities are defined as individual accounts in PJM's settlement systems that take financial positions in PJM markets and typically include banks and trading firms. International market participants that primarily take financial positions in PJM markets are generally considered to be financial entities even if they are utilities in their own countries.

Table 13-12 shows the 2025/2028 Long Term FTR Auction market cleared FTRs by trade type, organization type and FTR direction. The results show that financial entities purchased 92.7 percent of prevailing flow buy bid FTRs and 96.8 percent of counter flow buy bid FTRs with the result that financial entities purchased 94.7 percent of all long term FTR auction cleared buy bids. Physical entities purchased 5.3 percent of all cleared long term FTRs in

36 See Protest of the Independent Market Monitor for PJM, Docket No. ER24-374-000 (November 30, 2023); Comments of the Independent Market Monitor for PJM, Docket No. ER24-374-000 (February 6, 2024).

the 2025/2028 Long Term FTR Auction, down 1.0 percentage points from the previous Long Term FTR Auction.

Table 13-12 Long term FTR auction patterns of ownership by FTR direction: 2025/2028 auction

		FTR Direction		
Trade Type	Organization Type	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	7.3%	3.2%	5.3%
	Financial	92.7%	96.8%	94.7%
	Total	100.0%	100.0%	100.0%
Sell Offers	Physical	0.2%	0.2%	0.2%
	Financial	99.8%	99.8%	99.8%
	Total	100.0%	100.0%	100.0%

Table 13-13 shows the HHI for the individual periods in the 2017/2020 through 2025/2028 Long Term FTR Auctions and the entire auction. The YRALL auction was highly concentrated until its removal in the 2020/2023 Long Term Auction. The individual annual auctions are unconcentrated with the exception of years two and three of the 2017/2020 Auction and year three of the 2023/2026 Auction.

Table 13-13 Long term HHIs by auction

Auction	YR1	YR2	YR3	YRALL	Entire Auction
17/20 Long Term Auction	779	1779	1354	8533	884
18/21 Long Term Auction	711	940	749	8654	693
19/22 Long Term Auction	492	647	768	9954	506
20/23 Long Term Auction	567	575	638	NA	463
21/24 Long Term Auction	495	535	767	NA	460
22/25 Long Term Auction	518	626	888	NA	598
23/26 Long Term Auction	496	713	1049	NA	644
24/27 Long Term Auction	473	656	949	NA	592
25/28 Long Term Auction	485	603	786	NA	553

Table 13-14 shows the annual FTR auction cleared FTRs for the 2025/2026 planning period by trade type, organization type and FTR direction. In the Annual FTR Auction for the 2025/2026 planning period, financial entities purchased 89.6 percent of prevailing flow FTRs, down 0.9 percentage points, and 97.8 percent of counter flow FTRs, up 0.5 percentage points, with the results that financial entities purchased 93.0 percent, unchanged, of all annual FTR auction cleared buy bids for the 2025/2026 planning period.

Table 13-14 Annual FTR Auction patterns of ownership by FTR direction: 2025/2026 planning period

			FTR Direction		
Trade Type	Organization Type	Self-Scheduled FTRs	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	Yes	3.8%	0.0%	2.2%
		No	6.6%	2.2%	4.8%
		Total	10.4%	2.2%	7.0%
	Financial	No	89.6%	97.8%	93.0%
	Total		100.0%	100.0%	100.0%
Sell Offers	Physical		0.7%	1.9%	1.2%
	Financial		99.3%	98.1%	98.8%
	Total		100.0%	100.0%	100.0%

Table 13-15 shows the HHI values for cleared buy and self scheduled bids for the 2016/2017 through 2025/2026 Annual FTR Auctions. Obligation buy bids are consistently unconcentrated, while Option buy bids are unconcentrated to moderately concentrated. Cleared self scheduled bids are always highly concentrated.

Table 13-15 Annual auction HHIs by auction

Auction	Offset Type	Trade Type	HHI
25/26 Annual Auction	Obligation	Buy	425
	Obligation	SelfScheduled	2,650
	Option	Buy	815
24/25 Annual Auction	Obligation	Buy	399
	Obligation	Self Scheduled	2,975
	Option	Buy	822
23/24 Annual Auction	Obligation	Buy	425
	Obligation	Self Scheduled	2,595
	Option	Buy	1,220
22/23 Annual Auction	Obligation	Buy	424
	Obligation	Self Scheduled	3,398
	Option	Buy	884
21/22 Annual Auction	Obligation	Buy	420
	Obligation	Self Scheduled	3,291
	Option	Buy	957
20/21 Annual Auction	Obligation	Buy	278
	Obligation	Self Scheduled	2,970
	Option	Buy	1,299
19/20 Annual Auction	Obligation	Buy	251
	Obligation	Self Scheduled	2,661
	Option	Buy	978
18/19 Annual Auction	Obligation	Buy	357
	Obligation	Self Scheduled	2,620
	Option	Buy	1,213
17/18 Annual Auction	Obligation	Buy	303
	Obligation	Self Scheduled	2,794
	Option	Buy	2,099

Table 13-16 presents the monthly balance of planning period FTR auction cleared FTRs for the first ten months of the 2025/2026 planning period by trade type, organization type and FTR direction. Financial entities purchased 95.5 percent of prevailing flow FTRs, up 0.7 percentage points, and 97.9 percent of counter flow FTRs, up 1.6 percentage points, from the same period of the 2024/2025 planning period, with the result that financial entities purchased 96.6 percent, up 0.9 percentage points, of all prevailing and counter flow FTR buy bids in the monthly balance of planning period FTR auction for the first ten months of the 2025/2026 planning period.

Table 13-16 Monthly Balance of Planning Period FTR Auction patterns of ownership by FTR direction: 2025/2026 planning period

		FTR Direction		
Trade Type	Organization Type	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	4.5%	2.1%	3.4%
	Financial	95.5%	97.9%	96.6%
	Total	100.0%	100.0%	100.0%
Sell	Physical	0.3%	0.3%	0.3%
	Financial	99.7%	99.7%	99.7%
	Total	100.0%	100.0%	100.0%

Table 13-17 shows the monthly cumulative HHI values for cleared obligation MW for the first ten months of the 2025/2026 planning period monthly auctions for prevailing flow FTRs. Ownership of cleared prevailing flow bids was unconcentrated in 100 percent of auction periods.[37]

Table 13-17 Monthly Balance of Planning Period FTR Auction HHIs by period for prevailing flow FTRs

	Auction Period											
Auction	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY
Jun-25	470	486	481	623	793	704	615	580	586	732	731	812
Jul-25		479	498	613	718	673	619	606	590	665	639	736
Aug-25			479	690	742	749	687	606	587	723	695	833
Sep-25				593	730	757	693	588	592	750	736	876
Oct-25					588	770	685	585	598	753	765	902
Nov-25						643	690	591	608	769	798	936
Dec-25							614	600	634	806	829	956
Jan-26								559	644	814	809	953
Feb-26									563	795	794	915
Mar-26										692	744	870

Table 13-18 shows the monthly cumulative HHI values for cleared obligation MW for the first ten months of the 2025/2026 planning period monthly auctions by month for counter flow FTRs. Ownership of cleared counter flow bids was unconcentrated in 68.0 percent of periods and moderately concentrated in 32.0 percent of auction periods.

37 See *2025 Annual State of the Market Report for PJM*, Section 3: Energy Market, Competitive Assessment for HHI definitions.

Table 13-18 Monthly Balance of Planning Period FTR Auction HHIs by period for counter flow FTRs

	Auction Period											
Auction	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY
Jun-25	694	736	769	991	1073	1025	1079	1020	1123	1030	1185	1156
Jul-25		597	790	943	1027	1004	1000	1061	1042	1013	1155	1096
Aug-25			672	914	991	983	960	1041	1014	962	1064	1042
Sep-25				686	939	934	903	1014	988	963	1036	1009
Oct-25					733	889	895	1013	989	945	1008	970
Nov-25						722	856	965	965	932	963	942
Dec-25							700	925	941	930	964	935
Jan-26								740	892	888	940	918
Feb-26									781	885	951	920
Mar-26										772	907	895

Table 13-19 shows the average daily FTR ownership for all FTRs for the first ten months of the 2025/2026 planning period by organization type, by FTR direction and self scheduled FTRs. Financial entities owned 82.9 percent of all prevailing flow FTR MW, up 0.6 percentage points, and 96.0 percent of all counterflow FTR MW, up 1.4 percentage points, from the same period of the 2024/2025 planning period, with the result that financial entities purchased 89.2 percent, up 1.3 percentage points, of all prevailing flow and counter flow FTR MW for FTRs effective in the first ten months of the 2025/2026 planning period.

Table 13-19 Daily FTR held position ownership by FTR direction: June through March, 2025/2026 planning period

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	10.7%	4.0%	7.5%
Physical Self Scheduled	6.4%	0.0%	3.3%
Financial	82.9%	96.0%	89.2%
Total	100.0%	100.0%	100.0%

Market Performance

Volume

PJM regularly intervenes in the FTR market based on subjective judgment which is not based on clear or documented guidelines. Such intervention in the FTR market, or any market, is not appropriate and not consistent with the operation of competitive markets. In an apparent effort to manage FTR revenues, PJM may adjust normal transmission limits in the FTR auction model. If, in PJM's judgment, the normal transmission limit is not consistent with revenue adequacy goals and simultaneous feasibility, then transmission limits are reduced pro rata based on the MW of Stage 1A infeasibility and the availability of auction bids for counter flow FTRs.[38] PJM may also remove or reduce infeasibilities caused by transmission outages by clearing counter flow bids without being required to clear the corresponding prevailing flow bids.[39] The use of both of these procedures is contingent on the conditions that: PJM actions not affect the revenue adequacy of allocated ARRs; all requested self scheduled FTRs clear; and net FTR auction revenue is positive.

Long Term FTR Auction

In the 2025/2028 Long Term FTR Auction, 465,963 MW (23.5 percent of bid volume; 50.4 percent of total FTR volume) of counter flow FTR buy bids cleared, an increase from 304,456 MW and an increase from 47.7 percent of total FTR volume. In the same auction, prevailing flow FTR buy bids cleared 457,906 MW (9.6 percent of bid volume; 49.6 percent of total FTR volume) an increase from 334,216 MW and a decrease from 52.3 percent of total FTR volume. In the 2025/2028 Long Term FTR Auction, 57,108 MW (8.5 percent) of counter flow sell offers and 111,744 MW (12.6 percent) of prevailing flow sell offers cleared.

38 See "PJM Manual 6: Financial Transmission Rights," Rev. 34 (May 21, 2025).
39 See *id.*

Table 13-20 Long Term FTR Auction market volume: 2025/2028 auction

Trade Type	FTR Direction	Period Type	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Buy bids	Counter Flow	Year 1	242,087	796,792	203,768	25.6%	593,024	74.4%
		Year 2	185,209	618,940	134,421	21.7%	484,519	78.3%
		Year 3	158,723	564,607	127,774	22.6%	436,833	77.4%
		Total	586,019	1,980,339	465,963	23.5%	1,514,376	76.5%
	Prevailing Flow	Year 1	453,306	1,977,093	223,305	11.3%	1,753,789	88.7%
		Year 2	302,885	1,496,082	133,992	9.0%	1,362,090	91.0%
		Year 3	241,022	1,276,086	100,610	7.9%	1,175,476	92.1%
		Total	997,213	4,749,261	457,906	9.6%	4,291,355	90.4%
	Total		1,583,232	6,729,600	923,869	13.7%	5,805,731	86.3%
Sell offers	Counter Flow	Year 1	107,516	343,079	35,956	10.5%	307,123	89.5%
		Year 2	79,437	222,290	16,007	7.2%	206,284	92.8%
		Year 3	33,875	103,697	5,145	5.0%	98,552	95.0%
		Total	220,828	669,067	57,108	8.5%	611,958	91.5%
	Prevailing Flow	Year 1	120,708	496,953	64,811	13.0%	432,142	87.0%
		Year 2	77,520	306,273	38,556	12.6%	267,717	87.4%
		Year 3	26,584	85,163	8,377	9.8%	76,786	90.2%
		Total	224,812	888,388	111,744	12.6%	776,645	87.4%
	Total		445,640	1,557,455	168,852	10.8%	1,388,603	89.2%

Figure 13-3 shows the percent of FTR MW cleared, and bid and cleared volume, by direction, for each round of the Long Term FTR Auction from the 2015/2018 through the 2025/2028 auctions.

Figure 13-3 Long Term FTR Auction bid and cleared volume by round and direction

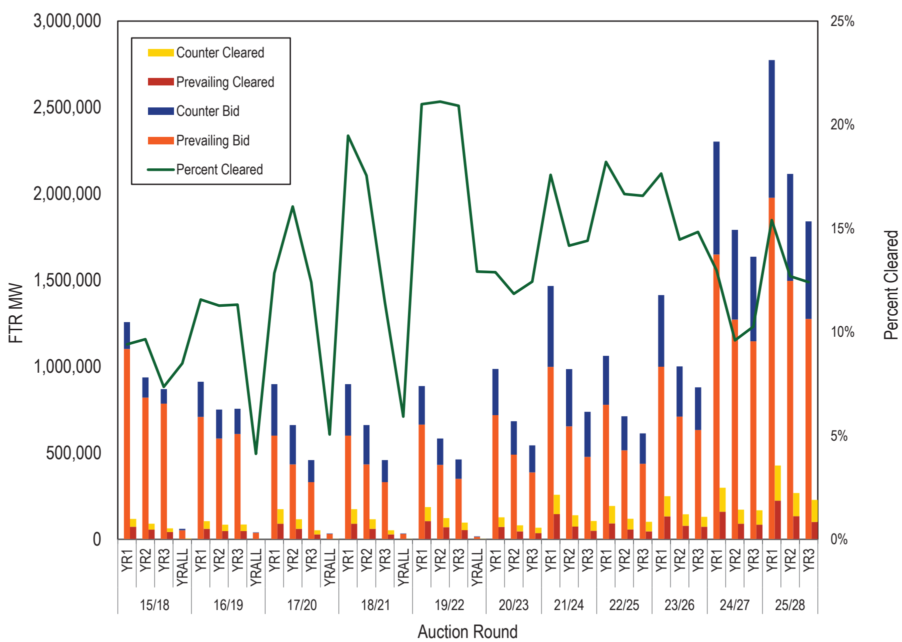


Table 13-21 compares cleared FTR obligations (not options) acquired in the Long Term FTR Auctions to the total cleared FTR obligations from the Annual FTR Auction, for FTRs in the 2014/2015 through 2025/2026 planning periods. A three year FTR is distributed to each individual planning period during its three year effective period. Long term FTRs that are effective in a single planning period were an average of 39.9 percent of total FTR volume in the 2014/2015 through 2025/2026 planning periods.

Table 13-21 Long Term and Annual Auction total cleared FTR MW

	Long Term FTR Product (Including YRALL)			Obligation Volume (MW)		
Effective Planning Period	YR3	YR2	YR1	Total Long Term	Annual (including self scheduled)	Long Term Percent of Total Cleared
2014/2015	81,666	86,754	131,911	300,330	356,522	45.7%
2015/2016	89,419	99,329	123,400	312,148	355,682	46.7%
2016/2017	97,837	95,637	107,182	300,656	397,258	43.1%
2017/2018	69,161	86,323	108,126	263,609	493,683	34.8%
2018/2019	87,232	109,827	176,998	374,057	549,669	40.5%
2019/2020	80,947	118,112	188,438	387,496	576,937	40.2%
2020/2021	54,451	125,330	127,054	306,835	525,550	36.9%
2021/2022	98,829	80,998	205,008	384,835	512,449	42.9%
2022/2023	67,603	120,621	193,268	381,492	467,194	45.0%
2023/2024	100,973	118,618	249,482	469,073	770,310	37.8%
2024/2025	101,674	144,699	298,773	545,146	944,669	36.6%
2025/2026	130,392	171,988	427,073	729,453	1,219,310	37.4%

Table 13-22 shows the MW proportion of FTRs by source and sink node type for cleared buy bids in the 2025/2028 Long Term FTR Auction. Generator to generator FTRs comprise 63.5 percent of all cleared FTR buy bids, up 1.6 percentage points from the 2024/2027 Long Term FTR Auction.

Table 13-22 Long Term FTR node type matrix: 2025/2028 auction

	Sink Type						
Source Type	Aggregate	Generator	Hub	Interface	Load	Residual Metered Aggregate	Zone
Aggregate	1.3%	6.9%	0.1%	0.2%	0.0%	0.2%	0.3%
Generator	6.3%	63.5%	2.1%	2.3%	0.4%	0.9%	2.6%
Hub	0.1%	0.6%	1.1%	0.1%	0.0%	0.1%	2.0%
Interface	0.0%	0.2%	0.0%	0.0%	0.0%	0.0%	0.1%
Load	0.0%	0.5%	0.0%	0.0%	0.0%	0.0%	0.0%
Residual Metered Aggregate	0.2%	1.4%	0.0%	0.0%	0.0%	0.0%	0.3%
Zone	0.3%	2.0%	1.0%	0.2%	0.0%	0.5%	2.1%

Annual FTR Auction

Table 13-23 shows the annual FTR auction market volume for the 2025/2026 Annual FTR Auction. Total FTR buy bids were 6,628,872 MW, up 39.8 percent from 4,741,013 MW for the previous Annual FTR Auction. For the 2025/2026 Annual FTR Auction 1,294,688 MW (19.5 percent) of buy bids cleared, up 29.6 percent from 999,108 MW (21.1 percent) for the previous Annual FTR Auction. There were 1,695,004 MW of sell offers, up 44.5 percent from 1,172,749 for the previous Annual FTR Auction. For the 2025/2026 Annual FTR Auction 183,410 MW (10.8 percent) of sell offers cleared, up 47.6 percent from 124,227 for the previous Annual FTR Auction. The total volume of cleared buy and self scheduled bids was 1,324,299 MW, up 28.8 percent from 1,028,420 MW in the previous Annual FTR Auction.

Table 13-23 Annual FTR Auction market volume: 2025/2026 auction

Trade Type	Type	FTR Direction	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Buy bids	Obligations	Counter Flow	378,977	1,930,773	549,391	28.5%	1,381,381	71.5%
		Prevailing Flow	673,791	3,556,006	640,307	18.0%	2,915,698	82.0%
		Total	1,052,768	5,486,779	1,189,699	21.7%	4,297,080	78.3%
	Options	Counter Flow	0	0	0	NA	0	NA
		Prevailing Flow	125,964	1,142,093	104,989	9.2%	1,037,104	90.8%
		Total	125,964	1,142,093	104,989	9.2%	1,037,104	90.8%
	Total	Counter Flow	378,977	1,930,773	549,391	28.5%	1,381,381	71.5%
		Prevailing Flow	799,755	4,698,099	745,297	15.9%	3,952,802	84.1%
		Total	1,178,732	6,628,872	1,294,688	19.5%	5,334,183	80.5%
Self-scheduled bids	Obligations	Counter Flow	126	48	48	100.0%	0	0.0%
		Prevailing Flow	8,762	29,563	29,563	100.0%	0	0.0%
		Total	8,888	29,611	29,611	100.0%	0	0.0%
Buy and self-scheduled bids	Obligations	Counter Flow	379,103	1,930,821	549,440	28.5%	1,381,381	71.5%
		Prevailing Flow	682,553	3,585,569	669,870	18.7%	2,915,698	81.3%
		Total	1,061,656	5,516,390	1,219,310	22.1%	4,297,080	77.9%
	Options	Counter Flow	0	0	0	NA	0	NA
		Prevailing Flow	125,964	1,142,093	104,989	9.2%	1,037,104	90.8%
		Total	125,964	1,142,093	104,989	9.2%	1,037,104	90.8%
	Total	Counter Flow	379,103	1,930,821	549,440	28.5%	1,381,381	71.5%
		Prevailing Flow	808,517	4,727,662	774,860	16.4%	3,952,802	83.6%
		Total	1,187,620	6,658,483	1,324,299	19.9%	5,334,183	80.1%
Sell offers	Obligations	Counter Flow	149,725	735,729	69,606	9.5%	666,123	90.5%
		Prevailing Flow	185,040	925,637	113,145	12.2%	812,492	87.8%
		Total	334,765	1,661,366	182,751	11.0%	1,478,615	89.0%
	Options	Counter Flow	0	0	0	NA	0	NA
		Prevailing Flow	8,856	33,638	659	2.0%	32,979	98.0%
		Total	8,856	33,638	659	2.0%	32,979	98.0%
	Total	Counter Flow	149,725	735,729	69,606	9.5%	666,123	90.5%
		Prevailing Flow	193,896	959,275	113,804	11.9%	845,471	88.1%
		Total	343,621	1,695,004	183,410	10.8%	1,511,594	89.2%

Figure 13-4 shows the percent of FTR MW cleared and bid and cleared volume, by direction, for each round of the Annual FTR Auction from the 2015/2016 planning period through the 2025/2026 planning period.

Figure 13-4 Annual FTR Auction bid and cleared volume by round and direction

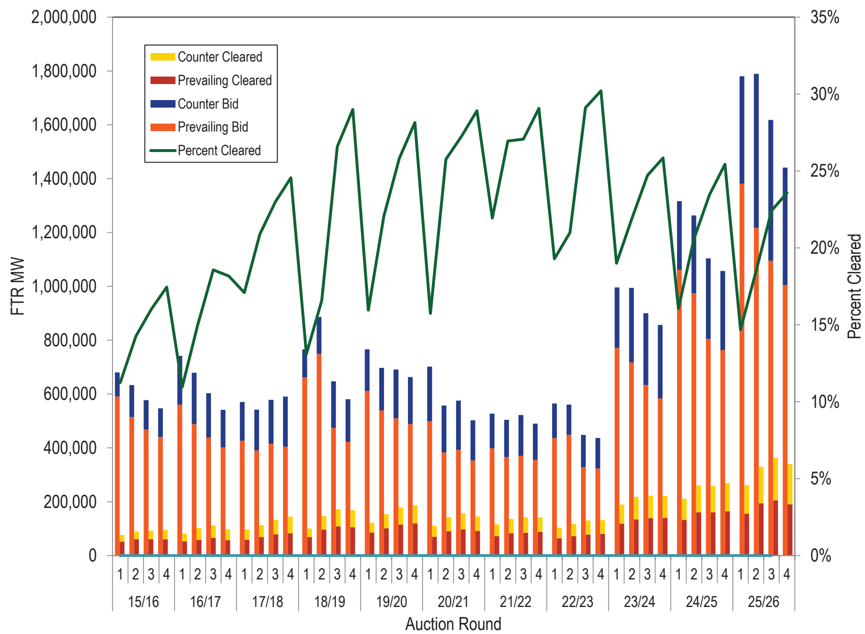


Figure 13-5 Comparison of self scheduled FTRs: 2009/2010 through 2025/2026 planning periods

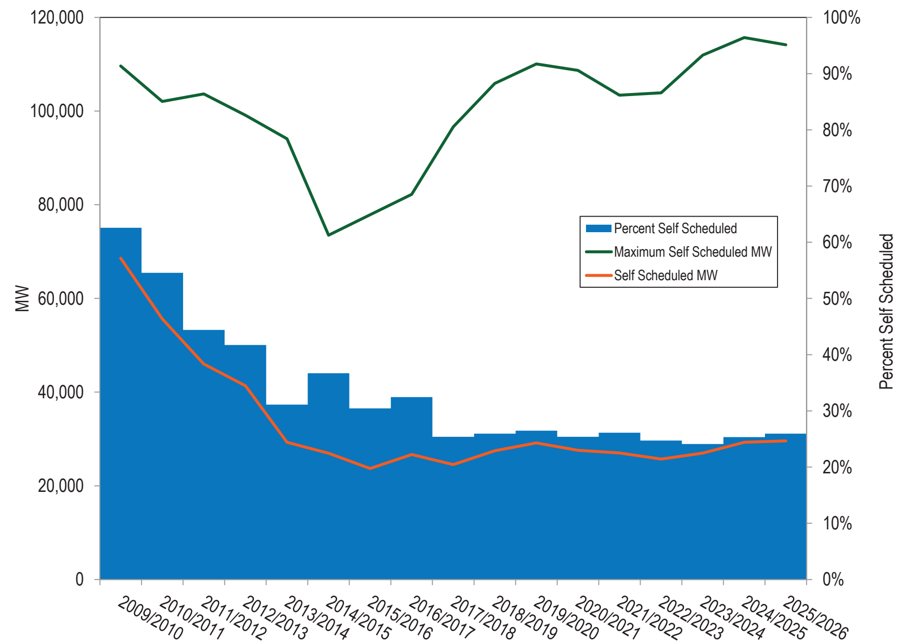


Figure 13-5 shows the proportion of ARRs self scheduled as FTRs for the last sixteen planning periods. The maximum possible level of self scheduled FTRs is equal to total ARRs. Eligible participants self scheduled 29,611MW (25.9 percent) of ARRs as FTRs for the 2025/2026 planning period, compared to 29,312 MW (25.3 percent) in the previous planning period.

Table 13-24 shows the MW proportion of FTRs by source and sink node type for cleared buy and self scheduled bids in the 2025/2026 Annual FTR Auction.

Generator to generator FTRs comprise 60.1 percent of all cleared FTR buy and self scheduled bids in the 2025/20265 Annual Auction, up 2.4 percentage points from the previous planning period. Generator to generator FTRs make up a disproportionate share of total FTRs. Congestion results from load paying more for generation than generators receive. By definition, congestion is between generator sources and load sinks. Generator to generator paths do not represent the delivery of generation to load. FTRs between generators simply create a speculative opportunity because they can be a low cost or zero cost FTR in the current design with a significant payoff if there is a price difference between the two nodes.

The MMU recommends that PJM examine the source and sink node combinations available in the FTR market and eliminate generation to generation paths and all other paths that do not represent the delivery of power to load.

Table 13-24 Annual auction FTR node type matrix by proportion of MW: 2025/2026 auction

	Sink Type						
Source Type	Aggregate	Generator	Hub	Interface	Load	Residual Metered Aggregate	Zone
Aggregate	1.4%	6.5%	0.1%	0.1%	0.3%	0.5%	0.0%
Generator	10.5%	60.1%	2.3%	0.7%	3.3%	5.7%	0.1%
Hub	0.2%	1.0%	0.5%	0.0%	0.2%	1.2%	0.0%
Interface	0.0%	0.4%	0.0%	0.0%	0.1%	0.0%	0.0%
Load	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%
Residual Metered Aggregate	0.2%	0.9%	0.0%	0.0%	0.0%	0.1%	0.0%
Zone	0.4%	1.1%	0.7%	0.1%	0.3%	0.8%	0.0%

Monthly Balance of Planning Period Auctions

Table 13-25 provides the monthly balance of planning period FTR auction market volume for the first ten months of the 2025/2026 and entire 2024/2025 planning periods. There were 60,011,812 MW of FTR obligation buy bids and 57,769,193 MW of FTR obligation sell offers for all bidding periods in the first ten months of the 2025/2026 planning period.[40] The monthly balance of planning period FTR auction cleared 14,367,562 (23.9 percent) of FTR obligation buy bids and 8,488,263 MW (14.6 percent) of FTR obligation sell offers.

There were 24,769,193 MW of FTR option buy bids and 5,769,090 MW of FTR option sell offers for all bidding periods in the Monthly Balance of Planning Period FTR Auctions for the first ten months of the 2025/2026 planning period. The monthly balance of planning period FTR auction auctions cleared 749,840 MW (3.0 percent) of FTR option buy bids and 1,220,643 MW (21.2 percent) of FTR option sell offers.

40 The term obligation is used only to distinguish FTRs from options.

Table 13-25 Monthly Balance of Planning Period FTR Auction market volume: June 2025 through March 2026

Monthly Auction	Type	Trade Type	Bid and RequestedCount	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Jun-25	Obligations	Buy bids	1,524,117	10,459,179	1,857,497	17.8%	8,601,683	82.2%
		Sell offers	1,672,291	7,831,025	1,599,672	20.4%	6,231,353	79.6%
	Options	Buy bids	265,505	4,907,680	142,485	2.9%	4,765,195	97.1%
		Sell offers	151,286	726,502	183,122	25.2%	543,380	74.8%
Jul-25	Obligations	Buy bids	1,461,684	9,825,906	2,030,984	20.7%	7,794,922	79.3%
		Sell offers	1,608,014	7,053,811	1,108,932	15.7%	5,944,879	84.3%
	Options	Buy bids	192,280	4,109,077	129,501	3.2%	3,979,576	96.8%
		Sell offers	167,051	839,164	151,938	18.1%	687,226	81.9%
Aug-25	Obligations	Buy bids	1,389,431	7,505,218	1,905,638	25.4%	5,599,580	74.6%
		Sell offers	1,454,737	6,916,441	887,665	12.8%	6,028,776	87.2%
	Options	Buy bids	148,953	3,021,657	94,914	3.1%	2,926,743	96.9%
		Sell offers	146,719	772,381	144,017	18.6%	628,365	81.4%
Sep-25	Obligations	Buy bids	1,224,942	6,808,072	1,753,024	25.7%	5,055,048	74.3%
		Sell offers	1,374,215	6,887,734	885,108	12.9%	6,002,626	87.1%
	Options	Buy bids	128,052	2,275,607	96,071	4.2%	2,179,536	95.8%
		Sell offers	135,829	703,499	128,738	18.3%	574,761	81.7%
Oct-25	Obligations	Buy bids	1,113,435	6,235,731	1,597,537	25.6%	4,638,195	74.4%
		Sell offers	1,260,502	6,508,856	760,306	11.7%	5,748,550	88.3%
	Options	Buy bids	106,509	2,321,999	66,598	2.9%	2,255,401	97.1%
		Sell offers	116,305	629,172	114,934	18.3%	514,238	81.7%
Nov-25	Obligations	Buy bids	992,819	5,651,963	1,407,040	24.9%	4,244,923	75.1%
		Sell offers	1,070,635	5,962,898	812,119	13.6%	5,150,779	86.4%
	Options	Buy bids	87,908	1,968,750	53,602	2.7%	1,915,148	97.3%
		Sell offers	103,859	570,872	110,578	19.4%	460,294	80.6%
Dec-25	Obligations	Buy bids	826,687	4,543,634	1,178,819	25.9%	3,364,815	74.1%
		Sell offers	960,553	5,377,220	736,306	13.7%	4,640,914	86.3%
	Options	Buy bids	71,601	1,939,135	51,101	2.6%	1,888,034	97.4%
		Sell offers	84,988	507,706	127,413	25.1%	380,293	74.9%
Jan-26	Obligations	Buy bids	734,406	3,462,240	981,515	28.3%	2,480,725	71.7%
		Sell offers	775,539	4,612,198	688,668	14.9%	3,923,531	85.1%
	Options	Buy bids	82,379	1,739,393	39,408	2.3%	1,699,985	97.7%
		Sell offers	68,387	410,084	89,250	21.8%	320,834	78.2%
Feb-26	Obligations	Buy bids	616,966	2,977,742	865,735	29.1%	2,112,007	70.9%
		Sell offers	663,526	3,804,169	574,018	15.1%	3,230,151	84.9%
	Options	Buy bids	64,142	1,361,817	37,763	2.8%	1,324,055	97.2%
		Sell offers	56,167	347,404	81,688	23.5%	265,715	76.5%
Mar-26	Obligations	Buy bids	506,097	2,542,126	789,773	31.1%	1,752,353	68.9%
		Sell offers	491,025	2,814,840	435,468	15.5%	2,379,372	84.5%
	Options	Buy bids	44,982	1,184,644	38,397	3.2%	1,146,248	96.8%
		Sell offers	39,380	262,308	88,966	33.9%	173,342	66.1%
2024/2025*	Obligations	Buy bids	10,250,462	51,695,684	10,486,345	20.3%	41,209,339	79.7%
		Sell offers	10,167,424	40,510,062	5,622,983	13.9%	34,887,079	86.1%
	Options	Buy bids	756,191	15,283,383	757,379	5.0%	14,526,004	95.0%
		Sell offers	899,936	5,387,701	1,041,790	19.3%	4,345,912	80.7%
2025/2026**	Obligations	Buy bids	10,390,584	60,011,812	14,367,562	23.9%	45,644,251	76.1%
		Sell offers	11,331,037	57,769,193	8,488,263	14.7%	49,280,930	85.3%
	Options	Buy bids	1,192,311	24,829,760	749,840	3.0%	24,079,919	97.0%
		Sell offers	1,069,971	5,769,090	1,220,643	21.2%	4,548,448	78.8%

*Shows 12 months for 2024/2025 **Shows 10 months for 2025/2026

Figure 13-6 shows the bid volume from each monthly auction for each period of the Monthly Balance of Planning Period FTR Auctions of the first ten months of the 2025/2026 planning period. The prompt month is the final month for which FTRs for a specific month are sold. For example, June is the prompt month for June FTRs sold in the June auction, which occurs in May. The bid volume for the non-prompt months is significantly lower than for the prompt months. On average, the non-prompt month bid volume is 52.1 percent of the prompt month bid volume.

Figure 13-6 Monthly Balance of Planning Period FTR Auction bid volume (MW per period): June 2025 through March 2026 Auction

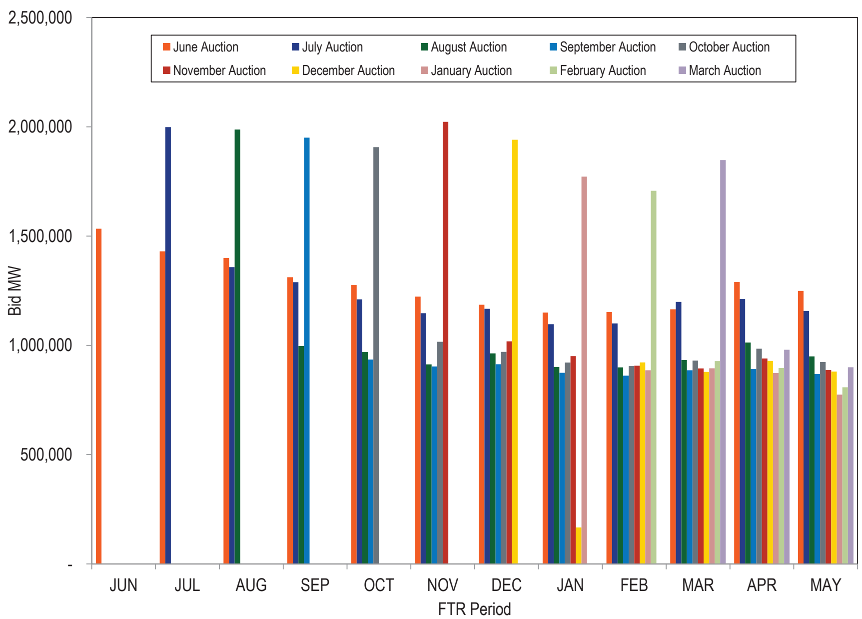


Figure 13-7 shows the cleared volume from each monthly auction for each period of the Monthly Balance of Planning Period FTR Auctions of the first ten months of the 2025/2026 planning period. The cleared volume for non-prompt months is also significantly lower than in prompt months. On average, the non-prompt months cleared volume is 35.5 percent of the prompt month cleared volume.

Figure 13-7 Monthly Balance of Planning Period FTR Auction cleared volume (MW per period): June 2025 through March 2026 Auction

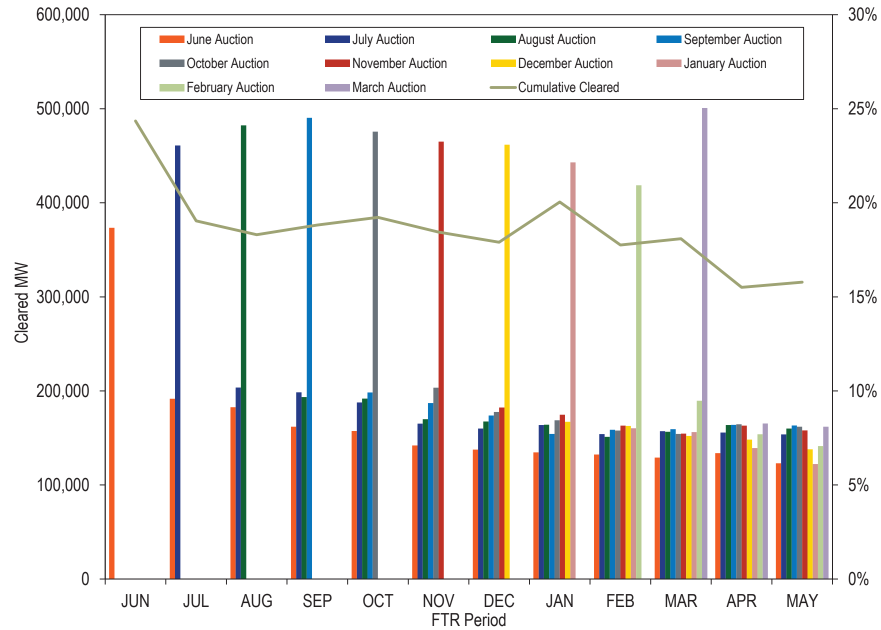


Figure 13-8 shows the FTR bid, net bid and cleared volume from June 2003 through March 2026 for Long Term, Annual and Monthly Balance of Planning Period Auctions. Cleared volume includes FTR buy and sell offers that were accepted. The net bid volume includes the total buy, sell and self scheduled offers, counting sell offers as a negative volume. The bid volume is the total of all bid and self scheduled offers, excluding sell offers. Following the implementation of the Historical Simulation Initial Margining (HSIM) analysis model in the September 2022 Monthly Auction, bid and net bid volumes have increased significantly. On average in the first ten months of the 2025/2026 planning period there was a 20.6 percent increase in bid volume and a 6.6

percent decrease in net bid volume compared to the same month in the previous planning period.

Figure 13-8 Long Term, Annual and Monthly FTR Auction bid and cleared volume: June 2003 through March 2026

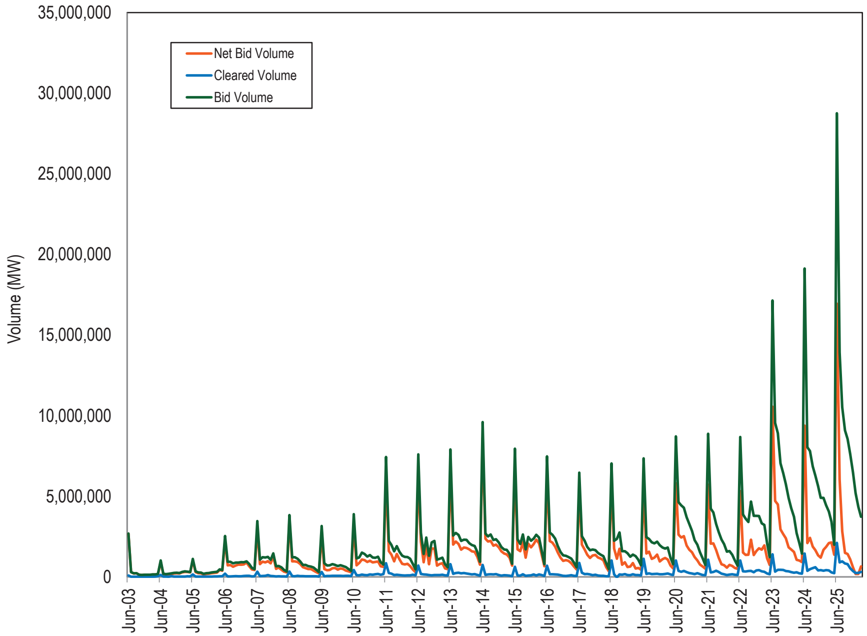
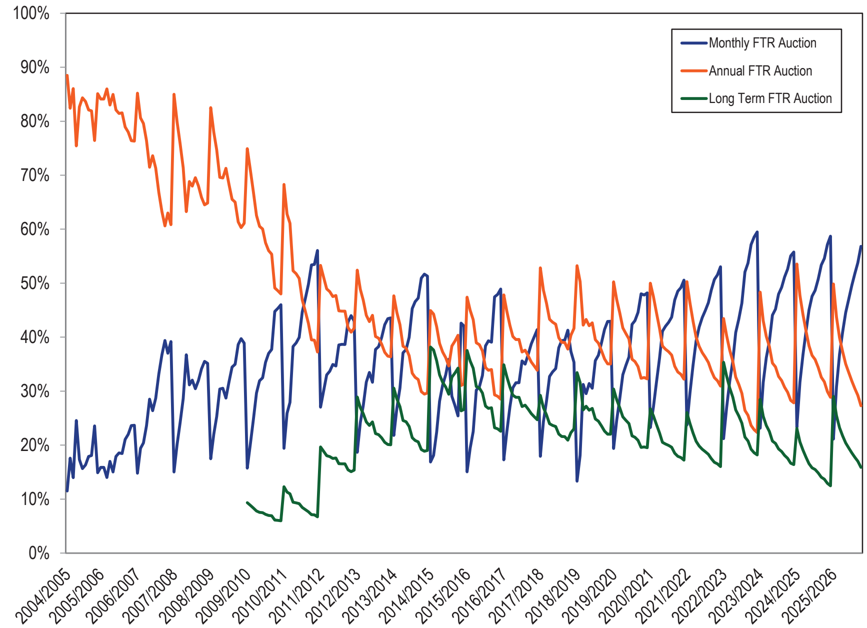


Figure 13-9 shows cleared auction volumes by auction type as a percent of the total FTR cleared volume by calendar months for June 2004 through March 2026. FTR volumes are included in the calendar month they are effective, with long term and annual FTR auction volumes spread equally to each month in the relevant planning period. Over the course of each planning period an increasing number of Monthly Balance of Planning Period FTRs are purchased, resulting in a greater share of total FTRs. When the Annual FTR Auction occurs, FTRs purchased in previous Monthly Balance of Planning Period Auctions, other than the current June auction, are no longer effective, resulting in a smaller share for monthly and a greater share for annual FTRs.

Figure 13-9 Cleared auction volume (MW) as a percent of total FTR cleared volume by calendar month: June 2004 through March 2026



Bilateral Market

Table 13-26 provides the PJM registered secondary bilateral FTR market volume for the first ten months of the 2025/2026 and the entire 2024/2025 planning periods. Market participants can buy and sell existing FTRs, outside of the auction process, through a voluntary bulletin board, termed the PJM bilateral market. FTRs can also be exchanged bilaterally without using the bulletin board. Prior to June 30, 2024, there was no requirement to report accurate detailed information about bilateral transactions settled through PJM billing systems. Effective June 30, 2024, the Commission accepted PJM's proposed revisions to the rules that required the reporting of bilateral price information and corroborating contract documents of any bilateral change of FTR ownership between participants/accounts that is settled through PJM settlement systems.[41] Bilateral transactions remain dependent on the

41 *See* 187 FERC ¶ 61,020.

contract established between the parties. PJM has no knowledge of bilateral transactions, or the terms and risks of bilateral transactions, that are done outside of PJM's bilateral market system. As a result, the bilateral data are not a reliable basis for evaluating actual bilateral activity in PJM FTRs.

In the first ten months of the 2025/2026 planning period there were two pairs of bilateral trading participants, one pair of unaffiliated participants, and 47 total bilateral FTR transactions. In the 2024/2025 planning period, there were eight total pairs of bilateral trading participants, three pairs of unaffiliated participants and 121 total bilateral FTR transactions.

Table 13-26 Secondary bilateral FTR market volume: 2024/2025 and 2025/2026 planning periods[42]

Planning Period	Type	Class Type	Volume (MW)
2024/2025	Obligation	24-Hour	1,196.4
		On Peak	480.4
		Daily Off Peak	127.9
		Weekend On Peak	147.8
		Total	1,952.5
	Option	24-Hour	0.0
		On Peak	0.0
		Daily Off Peak	0.0
		Weekend On Peak	0.0
		Total	0.0
2025/2026*	Obligation	24-Hour	294.0
		On Peak	255.7
		Daily Off Peak	276.9
		Weekend On Peak	272.0
		Total	1,098.6
	Option	24-Hour	0.0
		On Peak	0.0
		Daily Off Peak	0.0
		Weekend On Peak	0.0
		Total	0.0

*First ten months of 2025/2026

Price

Table 13-27 shows the cleared, weighted average prices by trade type, FTR direction, period type and class type for the 2025/2028 Long Term FTR Auction. Only FTR obligation products (no options) are available in the Long Term FTR Auctions. In this auction, weighted average buy bid counter flow and prevailing flow FTR prices were -$0.82 and $0.99, compared to -$0.55 and $0.64 from the 2024/2027 Long Term FTR Auction. Weighted average sell bid counter flow and prevailing flow FTR prices were -$0.79 and $0.73, compared to -$0.66 for counter flow FTRs and $0.64 for prevailing flow FTRs for the 2024/2027 Long Term FTR Auction.

Table 13-27 Long Term FTR Auction: weighted average cleared prices (Dollars per MW): 2025/2028 auction

			Class Type				
Trade Type	FTR Direction	Period Type	24-Hour	On Peak	Weekend On Peak	Daily Off Peak	All
Buy bids	Counter Flow	Year 1	($2.93)	($0.36)	($0.74)	($0.60)	($0.82)
		Year 2	($2.85)	($0.43)	($0.76)	($0.62)	($0.78)
		Year 3	($3.35)	($0.53)	($0.82)	($0.65)	($0.84)
		Total	($2.99)	($0.43)	($0.77)	($0.62)	($0.82)
	Prevailing Flow	Year 1	$2.44	$0.52	$0.85	$0.71	$0.92
		Year 2	$3.21	$0.59	$0.79	$0.68	$0.97
		Year 3	$4.45	$0.69	$0.89	$0.75	$1.19
		Total	$3.10	$0.58	$0.84	$0.71	$0.99
	Total		$0.52	$0.03	$0.07	$0.05	$0.09
Sell offers	Counter Flow	Year 1	($1.07)	($0.49)	($0.90)	($0.73)	($0.75)
		Year 2	($0.88)	($0.47)	($0.97)	($0.85)	($0.79)
		Year 3	($0.63)	($0.64)	($1.33)	($0.85)	($1.03)
		Total	($0.99)	($0.50)	($0.96)	($0.78)	($0.79)
	Prevailing Flow	Year 1	$1.66	$0.53	$0.82	$0.59	$0.72
		Year 2	$1.92	$0.62	$0.73	$0.63	$0.72
		Year 3	$3.51	$0.92	$0.79	$0.70	$0.85
		Total	$1.85	$0.59	$0.79	$0.61	$0.73
	Total		$0.99	$0.20	$0.21	$0.16	$0.22

Table 13-28 shows the weighted average cleared buy bid prices by trade type, FTR product, FTR direction and class type for the Annual FTR Auction for the 2025/2026 planning period. The weighted average cleared buy bid price in the

42 The 2024/2025 planning period covers bilateral FTRs that are effective for any time between June 1, 2024 through May 31, 2025, which originally had been purchased in a Long Term FTR Auction, Annual FTR Auction or Monthly Balance of Planning Period FTR Auction.

2025/2026 Annual FTR Auction was $2.88 per MW, up from $1.87 per MW in the 2024/2025 Annual FTR Auction.

Table 13-28 Annual FTR Auction weighted average cleared prices (Dollars per MW): 2025/2026 planning period

Trade Type	Type	FTR Direction	24-Hour	On Peak	Class Type Weekend On Peak	Daily Off Peak	All
Buy bids	Obligations	Counter Flow	($1.46)	($0.59)	($0.44)	($0.32)	($0.52)
		Prevailing Flow	$2.79	$0.93	$0.76	$0.52	$0.96
		Total	$1.62	$0.25	$0.19	$0.12	$0.29
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$0.56	$0.71	$0.46	$0.31	$0.53
		Total	$0.56	$0.71	$0.46	$0.31	$0.53
Self-scheduled bids	Obligations	Counter Flow	($0.24)	$0.00	$0.00	$0.00	($0.24)
		Prevailing Flow	$3.27	$1.88	$1.19	$0.69	$3.18
		Total	$3.27	$1.88	$1.19	$0.69	$3.17
Buy and self-scheduled bids	Obligations	Counter Flow	($1.46)	($0.59)	($0.44)	($0.32)	($0.52)
		Prevailing Flow	$3.06	$0.93	$0.76	$0.52	$1.19
		Total	$2.41	$0.25	$0.19	$0.12	$0.47
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$0.56	$0.71	$0.46	$0.31	$0.53
		Total	$0.56	$0.71	$0.46	$0.31	$0.53
Sell offers	Obligations	Counter Flow	($1.76)	($0.87)	($0.71)	($0.44)	($0.80)
		Prevailing Flow	$2.06	$0.86	$0.66	$0.55	$0.81
		Total	$0.26	$0.24	$0.16	$0.17	$0.20
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$2.02	$2.21	$1.48	$0.98	$1.68
		Total	$2.02	$2.21	$1.48	$0.98	$1.68

Table 13-29 shows the cleared buy bid volume, cleared buy bid revenue and cleared revenue/cleared MW for the last twelve planning periods. In the 2014/2015 planning period the $/MW increased significantly from the 2013/2014 planning period due to PJM's decisions to limit capacity through conservative modeling. In the 2017/2018 Annual FTR Auction, the $/MW decreased to lower than 2013/2014 levels, due in part to the partial relaxation of PJM's conservative modeling practices due to the reassignment of balancing congestion and M2M payments to load and exports. This reduction continued into the 2019/2020 planning period. Due to the more restrictive modeling for the 2022/2023 planning period (relative to the 2021/2022 planning period), quantities and revenue were similar to 2016/2017 levels, when PJM was restricting the FTR market to account for balancing congestion. The reassignment of balancing congestion and M2M payments to load did not increase the per MW value of ARRs.

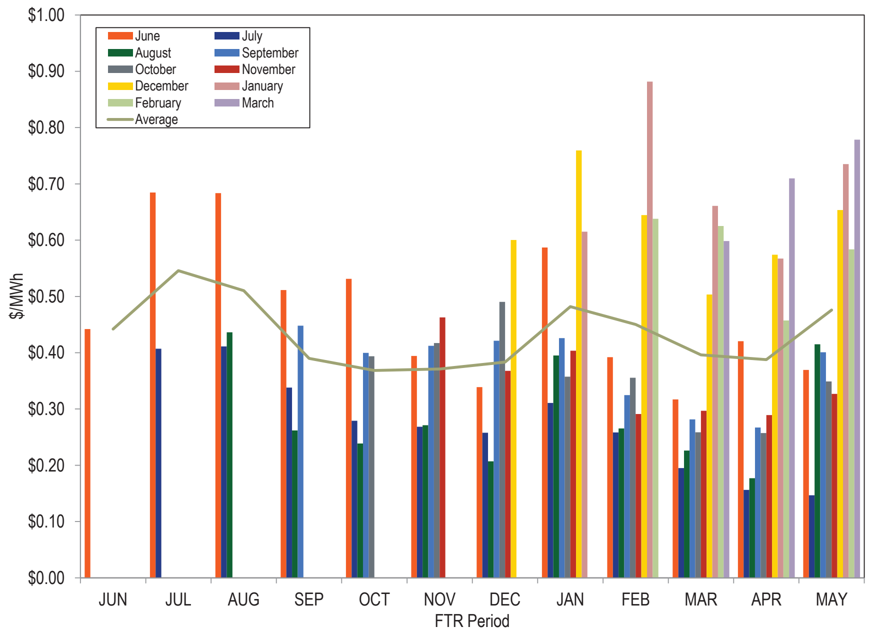
The 2023/2024 Annual FTR Auction was the first Annual FTR Auction to use the HSIM model. Following the high revenue from the 2022/2023 planning period, and the implementation of the HSIM model, the 2023/2024 Annual FTR Auction cleared buy bid volume increased by 75.9 percent. For the 2023/2024 Annual FTR Auction, the cleared buy bid volume increased 75.9 percent, total buy bid revenue decreased 12.6 percent, and buy bid revenue per MW decreased 50.1 percent. For the 2024/2025 Annual FTR Auction, cleared buy bid volume increased 17.4 percent, total buy bid revenue decreased 1.7 percent, and buy bid revenue per MW decreased 16.3 percent. In the 2025/2026 Annual FTR Auction, cleared buy bid volume increased by 29.6 percent, and buy bid revenue increased by 34.2 percent compared to the previous annual FTR auction.

Table 13-29 Cleared volume, revenue and $/MW: 2012/2013 through 2025/2026 Annual FTR Auction

	Buy Bid Volume	Cleared Buy Bid Volume	Percent Cleared	Buy Bid Revenue (millions)	Buy Bid Revenue ($/MW)
2012/2013	2,520,119	329,578	13.1%	$389.1	$1,181
2013/2014	3,245,033	391,148	12.1%	$382.5	$978
2014/2015	3,243,346	338,879	10.4%	$506.3	$1,494
2015/2016	2,437,964	354,630	14.5%	$620.5	$1,750
2016/2017	2,565,494	393,509	15.3%	$615.8	$1,565
2017/2018	2,281,534	488,734	21.4%	$406.5	$832
2018/2019	2,880,105	587,628	20.4%	$635.7	$1,082
2019/2020	2,787,716	611,878	21.9%	$649.0	$1,061
2020/2021	2,336,551	556,034	23.8%	$449.6	$809
2021/2022	2,043,408	535,277	26.2%	$519.0	$970
2022/2023	1,984,377	483,988	24.4%	$1,096.3	$2,265
2023/2024	3,746,935	851,248	22.7%	$957.9	$1,125
2024/2025	4,741,013	999,108	21.1%	$941.4	$942
2025/2026	6,628,872	1,294,688	19.5%	$1,263.6	$976

Figure 13-10 shows the weighted average cleared buy bid price of obligations in the Monthly Balance of Planning Period FTR Auctions by bidding period for the first ten months of the 2025/2026 planning period and the average price per MWh for each of the FTR periods. The average price per MWh across all bidding periods for the first ten months of the 2025/2026 planning period was $0.43.

Figure 13-10 Monthly Balance of Planning Period FTR Auction cleared weighted-average buy bid price per period (Dollars per MWh): 2025/2026 planning period



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 the FTR. FTR profitability is relevant only to participants purchasing FTRs and is not relevant to self scheduled FTRs. For a prevailing flow FTR, the FTR revenue is the actual revenue that an FTR holder is paid as the target allocation plus the auction price from the sale of the FTR, if relevant, and the FTR cost is the auction price. For a counter flow FTR, the FTR revenue is the auction price that an FTR holder is paid to take the FTR plus the positive auction price from the sale of the FTR, if relevant, and the FTR cost is the target allocation that the FTR holder must pay plus the negative auction price from the sale of the FTR, if relevant. Profits include the payment of surplus to FTRs. Bilateral transactions are excluded from the profit calculations. Bilateral profits and losses net to zero in market total profits and losses. ARR holders that self schedule FTRs receive congestion revenues but do not receive profits from those FTRs because ARR holders are assigned the rights to congestion revenues which they choose to take directly as the congestion payments associated with the corresponding FTRs.

Profits in the first 10 months of the 2025/2026 planning period include the auction cost and revenue from both buying and selling FTRs that were effective from June 2025 through March 2026. This includes FTRs from the 2023/2026, 2024/2027 and 2025/2028 Long Term auctions, the 2025/2026 Annual auction, and the Monthly auctions from June 2025 through March 2026. The costs and revenues of the yearly FTR products are prorated based on the period of the FTRs. Any revenues or costs related to bilateral transactions are not included in profits.

Hourly FTR profits are the sum of the hourly revenues minus the hourly costs for each FTR. The hourly revenues equal any positive hourly FTR target allocations, adjusted by the payout ratio plus any hourly auction revenues from the sale and/or the purchase of the FTR. The hourly auction costs equal any negative hourly FTR target allocations plus any hourly auction costs from the purchase and/or the sale of the FTR. The hourly auction costs and auction revenues are the product of the FTR MW and the auction price divided by the period of the FTR in hours. The FTR revenues do not include after the fact adjustments which are very small and do not occur in every month.

The surplus includes surplus day-ahead congestion revenue and FTR auction surplus. The surplus is first allocated to FTR holders to cover any shortfall in paying FTR target allocations for the current month or prior months in the planning period. A negative surplus (shortfall) at the end of the planning period is a deficiency that is charged as FTR uplift to FTR holders. The end of planning period surplus or uplift was distributed to FTR holders prorata based on FTR positive target allocations through the 2017/2018 planning period. Beginning with the 2018/2019 planning period, any surplus is given to FTR holders only up to FTR target allocations within the planning period, and, after any surplus assigned to FTRs, the net surplus at the end of the planning period is distributed to ARR holders. Profits include any surplus distribution or uplift payments that was used to satisfy any shortfall in FTR target allocations.

The fact that FTR profits in each planning period have been positive for financial entities as a group, regardless of the payout ratio, raises questions about the competitiveness of the market. FTR profits for financial entities were not positive in the 2019/2020 planning period when accounting for GreenHat losses, but were positive otherwise. FTR profits for financial entities without GreenHat losses were positive in every planning period from 2012/2013 through 2025/2026 except the 2016/2017 planning period, and were positive if summed over the entire period. Financial entities have been much more profitable than physical and physical ARR entities combined except for the 2015/2016 and the 2016/2017 planning periods (Table 13-33). It is not clear, in a competitive market, why FTRs remain persistently profitable for financial entities and much more profitable for financial entities than for other participants. In a competitive market, it is be expected that profits would be competed to zero.

Table 13-30 lists FTR profits, and the congestion returned through self scheduled FTRs, by organization type and FTR direction in the first 10 months of the 2025/2026 planning period. All physical participants who were assigned ARRs are classified as physical. Some participants that are not eligible for ARRs are classified as physical because they are physical participants, for example companies that own only generation.

In the first 10 months of the 2025/2026 planning period, physical participants, including physical ARR and IARR participants, received $541.8 million in profits on FTRs purchased directly (not self scheduled), up from $54.3 million profits in the same time period in the 2024/2025 planning period. Financial participants, including financial IARR participants, received $1.3 billion in profits, up from $744.7 million in profits in the same time period in the 2024/2025 planning period.[43] Some IARRs owned by financial participants were self scheduled as FTRs, which received $348,669. Self scheduled FTRs have zero cost. Physical ARR holders who self scheduled FTRs received $1.3 billion in congestion revenues, up from $465.8 million in revenue in the same time period in the 2024/2025 planning period. Revenues from self scheduled FTRs are a return of congestion to the load that paid the congestion and are not profits. Since the revenue from self scheduled FTRs is not profit it is excluded from the other tables in the profitability section.

Table 13-30 FTR profits and revenues by organization type and FTR direction: June through March, 2025/2026

	Purchased FTRs Profit			Self Scheduled FTRs Revenue Returned		
Organization Type	Prevailing Flow	Counter Flow	Total	Prevailing Flow	Counter Flow	Total
Financial	$2,245,800,147	($908,233,550)	$1,337,566,597	$348,669		$348,669
Physical	$247,376,787	($19,148,940)	$228,227,847			
Physical ARR	$433,407,943	($119,863,354)	$313,544,589	$1,262,957,762	($35,799)	$1,262,921,963
Total	$2,926,584,876	($1,047,245,843)	$1,879,339,033	$1,263,306,431	($35,799)	$1,263,270,632

Table 13-31 compares the revenue from self scheduled FTRs and the ARR target allocation if the self scheduled FTRs were held as ARRs. Table 13-31 shows whether the self scheduled FTR holders were better off by self scheduling compared with holding ARRs. In the first 10 months in the 2025/2026 planning period, the total revenue returned to self scheduled FTRs was $1.3 billion. If the self scheduled FTRs were held as ARRs, they would have received $625.8 million in ARR target allocation, or only 49.6 percent of the revenue received from self scheduled FTRs. One self scheduled FTR holder accounted for $670.6 million, or 69.5 percent, of the total revenue received by all self scheduled FTRs in the first 10 months of the 2025/2026 planning period.

43 There are financial participants who hold IARRs. The IARRs held by the financial participants were originally assigned to transmission upgrades associated with generation interconnection projects where the participant subsequently sold the associated physical assets (generation units) but kept the associated IARRs. Since these participants have not offered MW into the physical energy or capacity market and currently only hold financial positions, they are currently classified as financial participants.

able 13-31 Self scheduled FTR revenues and unrealized ARR target allocation: June through March, 2025/2026

Organization	Self Scheduled FTRs Revenue Returned			Unrealized ARR Target Allocation		
Type	Prevailing Flow	Counter Flow	Total	Prevailing Flow	Counter Flow	Total
Financial	$348,669		$348,669	$212,128		$212,128
Physical						
Physical ARR	$1,262,957,762	($35,799)	$1,262,921,963	$625,854,072	($84,600)	$625,769,473
Total	$1,263,306,431	($35,799)	$1,263,270,632	$626,066,201	($84,600)	$625,981,601

Table 13-32 lists the monthly FTR profits for the 2024/2025 planning period and the first 10 months of the 2025/2026 planning period by organization type. In the first 10 months of the 2025/2026 planning period, profits for all participants were $1.9 billion, up from $799.0 million in profits in the same time period in the 2024/2025 planning period and the highest level of profits since the 2012/2013 planning period. The increase in profits is due to the increase in FTR target credit. January had the largest monthly profit in the first 10 months of the 2025/2026 planning period, $540.7 million, the largest monthly profit since the 2013/2014 planning period. The largest month to month increase in profits in the first 10 months of the 2025/2026 planning period was also in January, an increase of $410.9 million. Among organization types, financial organizations' profits were the largest, $1.3 billion, or 71.2 percent of the market's total profits. Financial organizations had the largest increase in profits, an increase of $592.8 million. Physical organizations had the smallest profits among organization types, $228.2 million.

Table 13-32 Monthly FTR profits by organization type: 2024/2025 through March 2025/2026

	Organization Type			
Month	Financial	Physical	Physical ARR	Total
Jun-24	$47,118,337	($625,023)	($6,496,086)	$39,997,228
Jul-24	$140,890,180	$26,747,762	$3,673,731	$171,311,673
Aug-24	$89,115,812	$14,471,496	($3,597,813)	$99,989,494
Sep-24	$38,225,761	$5,734,554	($3,506,030)	$40,454,285
Oct-24	$34,019,402	$4,437,290	$4,457,735	$42,914,427
Nov-24	$4,454,325	($4,204,643)	($11,749,666)	($11,499,985)
Dec-24	$94,290,172	$23,591,538	($119,565)	$117,762,146
Jan-25	$135,793,868	$4,793,121	($10,788,364)	$129,798,624
Feb-25	$46,755,828	$12,458,346	($17,964,016)	$41,250,157
Mar-25	$114,057,458	$6,111,111	$6,838,610	$127,007,179
Apr-25	$60,134,385	($3,340,649)	$2,667,505	$59,461,242
May-25	$49,921,607	($5,061,517)	($5,977,119)	$38,882,971
Summary for Planning Period 2024/2025				
Total	$854,777,135	$85,113,384	($42,561,078)	$897,329,441
Jun-25	$92,206,975	$10,730,035	$13,494,064	$116,431,074
Jul-25	$165,773,391	$29,775,894	$25,986,128	$221,535,414
Aug-25	$45,813,799	$6,474,427	($21,925,617)	$30,362,609
Sep-25	$49,029,634	$8,259,195	$20,164,447	$77,453,277
Oct-25	$109,152,868	($2,911,850)	$18,999,374	$125,240,392
Nov-25	$61,740,719	$5,688,375	$18,925,861	$86,354,955
Dec-25	$183,209,865	$40,870,109	$31,100,999	$255,180,973
Jan-26	$332,432,616	$78,522,390	$129,732,020	$540,687,026
Feb-26	$232,902,253	$44,083,845	$50,168,556	$327,154,654
Mar-26	$65,304,476	$6,735,426	$26,898,756	$98,938,658
Summary for Planning Period 2025/2026				
Total	$1,337,566,597	$228,227,847	$313,544,589	$1,879,339,033

Table 13-33 lists the historical profits by planning period by organization type beginning in the 2012/2013 planning period for purchased FTRs. (Profits do not include congestion revenue to self scheduled FTRs.) The rules governing the allocation of surplus are described later in this section.

Table 13-33 FTR profits by organization type: 2012/2013 through 2025/2026

		2012/2013	2013/2014	2014/2015	2015/2016	2016/2017	2017/2018	2018/2019
Financial	Profit	$201,825,234	$913,502,323	$250,551,943	$68,895,867	($12,525,947)	$239,981,474	$113,086,231
	Surplus	($50,304,408)	($145,080,521)	$19,453,837	$4,921,078	$8,810,267	$90,361,918	
	Total	$151,520,826	$768,421,802	$270,005,781	$73,816,945	($3,715,680)	$330,343,392	$113,086,231
Financial without GreenHat	Profit	$201,825,234	$913,502,323	$250,551,785	$70,094,918	($11,821,248)	$240,111,850	$223,376,757
	Surplus	($50,304,408)	($145,080,521)	$19,453,837	$4,921,078	$8,810,267	$90,361,918	
	Total	$151,520,826	$768,421,802	$270,005,623	$75,015,995	($3,010,981)	$330,473,768	$223,376,757
Physical	Profit	$68,537,800	$297,456,284	$82,853,390	$10,007,327	($4,010,669)	$57,532,872	($5,945,233)
	Surplus	($41,626,011)	($53,642,077)	$5,395,706	$1,865,146	$4,181,855	$34,296,618	
	Total	$26,911,789	$243,814,207	$88,249,096	$11,872,473	$171,186	$91,829,490	($5,945,233)
Physical ARR	Profit	$26,572,818	$366,128,947	$112,609,140	$82,181,795	($2,468,152)	$66,458,939	($6,248,557)
	Surplus	($25,873,836)	($81,279,067)	$18,515,990	$7,110,576	$12,040,688	$47,753,635	
	Surplus from Self scheduled FTRs	($45,978,766)	($81,765,964)	$15,530,158	$3,073,711	$6,469,297	$42,513,186	
	Total	$698,982	$284,849,881	$131,125,130	$89,292,371	$9,572,536	$114,212,574	($6,248,557)
Total		$179,131,597	$1,297,085,890	$489,380,007	$174,981,788	$6,028,043	$536,385,456	$100,892,442

		2019/2020	2020/2021	2021/2022	2022/2023	2023/2024	2024/2025	2025/2026
Financial	Profit	($21,139,644)	$280,586,579	$831,489,515	$376,720,527	$227,123,570	$854,777,135	$1,337,566,597
	Surplus							
	Total	($21,139,644)	$280,586,579	$831,489,515	$376,720,527	$227,123,570	$854,777,135	$1,337,566,597
Financial without GreenHat	Profit	$25,150,852	$280,906,014	$831,489,515	$376,720,527	$227,123,570	$854,777,135	$1,337,566,597
	Surplus							
	Total	$25,150,852	$280,906,014	$831,489,515	$376,720,527	$227,123,570	$854,777,135	$1,337,566,597
Physical	Profit	($42,860,656)	$60,941,495	$228,289,196	$10,155,622	$3,268,080	$85,113,384	$228,227,847
	Surplus							
	Total	($42,860,656)	$60,941,495	$228,289,196	$10,155,622	$3,268,080	$85,113,384	$228,227,847
Physical ARR	Profit	($49,614,191)	$18,982,052	$35,163,444	($14,794,445)	$12,419,666	($42,561,078)	$313,544,589
	Surplus							
	Surplus from Self scheduled FTRs							
	Total	($49,614,191)	$18,982,052	$35,163,444	($14,794,445)	$12,419,666	($42,561,078)	$313,544,589
Total		($113,614,490)	$360,510,126	$1,094,942,155	$372,081,704	$242,811,317	$897,329,441	$1,879,339,033

* The first 10 months of the 2025/2026 planning period

Table 13-34 shows the profits and losses of the five most and the five least profitable participants by ownership type. Total MWh is the sum of all MWh by ownership type regardless of profitability. The Top 5 Profit is the sum of the profits of the five most profitable participants by ownership type. The Top 5 Profit/MWh is the Top 5 Profit divided by the sum of the MWh of the top 5 participants by ownership type. The Top 5 Market Share of MWh is the sum of the MWh of the top 5 participants by ownership type divided by Total MWh of that ownership type. The Top 5 Profit Share Among Profitable Participants is the Top 5 Profit divided by the sum of the profits of all profitable participants by ownership type. The same logic applies for the statistics related to the Bottom 5 participants. The All row considers all ownership types when selecting the Top 5 and Bottom 5 participants.

The sum of the Top 5 financial participants' profits was the largest of all the ownership types, $563.5 million, but had the lowest profit per MWh. Similarly, the Bottom 5 financial participants' sum of losses was the largest, $131.1 million, while their loss per MWh was the smallest. In contrast, the Top 5 physical participants had the smallest total profits but their profit per MWh was the largest. The Bottom 5 physical participants had the largest total losses while the Bottom 5 physical ARR participant's loss per MWh was the largest. In other words, financial participants operate at larger volumes with smaller per MWh profits and losses, while physical participants operate at smaller volumes with higher per MWh profits and losses in the first 10 months of the 2025/2026 planning period. When all participants across ownership types are considered, three of the Top 5 participants and all of the Bottom 5 participants were financial participants.

There are participants who have had persistent losses for multiple years. It is possible for PJM FTR participants to have complementary positions in other trading platforms such as the Intercontinental Exchange (ICE) or Nodal Exchange or in other products in the PJM market.

Table 13-34 Top 5 and bottom 5 FTR profits by ownership type: June through March, 2025/2026

Organization Type	Total MWh	Top 5 Profit	Top 5 Profit/MWh	Top 5 Market Share in MWh	Top 5 Profit Share Among Profitable Participants	Bottom 5 Loss	Bottom 5 Loss/MWh	Bottom 5 Market Share in MWh	Bottom 5 Loss Share Among Unprofitable Participants
Financial	5,283,741,211	$563,504,492	$0.59	18.0%	35.8%	($131,076,878)	($0.21)	11.9%	55.2%
Physical	151,135,037	$231,884,170	$2.64	58.2%	93.9%	($16,938,105)	($0.60)	18.5%	90.0%
Physical ARR	289,355,538	$347,394,581	$1.43	84.0%	95.8%	($27,971,615)	($2.29)	4.2%	57.0%
All	5,724,231,787	$804,103,673	$1.23	11.4%	36.8%	($131,076,878)	($0.21)	11.0%	42.9%

Table 13-35 shows the shares of profitable and unprofitable participants by ownership type weighted by FTR MW in the first 10 months of the 2025/2026 planning period. There were more profitable participants than unprofitable participants for each organization type and for market total. Compared with the same time period in the 2024/2025 planning period, in the first 10 months of the 2025/2026 planning period, the share of profitable participants decreased by 7.5 percentage points from 88.3 percent to 80.8 percent. Financial organizations were the only organization type whose share of profitable participants decreased. Financial organizations' share of profitable participants decreased while their total profits increased. Profits were more concentrated among Financial organizations in the first 10 months of the 2025/2026 planning period compared with the same time period in the 2024/2025 planning period.

Table 13-35 Share of participants MWh by profitability by ownership type: June through March, 2025/2026

Organization Type	Unprofitable	Profitable
Financial	19.2%	80.8%
Physical	35.3%	64.7%
Physical ARR	9.6%	90.4%
Total	19.2%	80.8%

Table 13-36 show the top 5 and bottom 5 profitable participants across all ownership types and their profits and losses in the first 10 months of the 2025/2026 planning period.

Table 13-36 Top 5 and Bottom 5 Profitable participants across all ownership types

Top 5 Participants			Bottom 5 Participants		
Organization	Organization Type	Profit	Organization	Organization Type	Loss
Constellation Energy Generation, LLC	Physical	$295,285,165	Viribus Fund LP	Financial	($47,298,595)
Susquehanna International Group, LLP	Financial	$150,854,220	Vitol Inc.	Financial	($26,991,782)
Appian Way Energy Partners East, LLC	Financial	$133,574,257	Citadel Energy Investments Ltd.	Financial	($26,357,975)
Elliott Bay Energy Trading, LLC	Financial	$116,693,249	Mercuria Energy Group Ltd	Financial	($16,118,424)
Quantum Energy Partners, LLC	Physical	$107,696,781	Electricite de France	Financial	($14,310,101)

Table 13-37 shows the profits by source and sink node type in the first 10 months of the 2025/2026 planning period. The sink total row is the sum of all profits and losses of FTRs that have the same sink node type. The source total column is the sum of all profits and losses of FTRs that have the same source node type. The profits of generator to generator FTRs were the largest, $586.4 million in the first 10 months of the 2025/2026 planning period and had the third largest increase in profits ($241.9 million increase) following zone to hub FTRs ($301.2 million increase) compared with the same time period in the 2024/2025 planning period. The profits of hub to hub FTRs were the second largest, $290.0 million and had the second largest increase in profits ($249.9 million increase). The losses of hub to zone FTRs were the largest, a loss of $159.5 million, in the first 10 months of the 2025/2026 planning period.

Table 13-37 Profits by node type matrix: June through March, 2025/2026

	Sink Type								
Source Type	Aggregate	EHVAGG	Generator	Hub	Interface	Load	Residual Metered Aggregate	Zone	Source Total
Aggregate	($4,707,373)	$278,656	($8,914,053)	$2,520,715	$1,649,041	($1,630,433)	$3,005,851	$499,026	($7,298,570)
EHVAGG	$503,880	$4,228,409	$8,577,257	$95,264	$2,179	$16,269,119	$140,256	$23,844	$29,840,208
Generator	$267,066,017	$5,449,324	$586,408,317	$215,221,792	$23,011,905	$34,967,465	$56,117,933	$226,311,298	$1,414,554,050
Hub	($12,039,980)	$621,329	$13,525,865	$289,953,952	($9,460,234)	$481,783	$11,813,479	($159,518,878)	$135,377,316
Interface	($187,034)	($10,961)	($11,686,222)	$2,967,746	$453,236	$1,049,289	$1,093,059	($1,691,723)	($8,012,610)
Load	$653,987	($7,797,126)	($3,337,464)	$532,350	$127,581	$40,803,049	($85,465)	$51,967	$30,948,878
Residual Metered Aggregate	($567,517)	($154,038)	($21,716,335)	($1,382,528)	($172,637)	$622,991	$2,658,601	$973,964	($19,737,500)
Zone	$2,175,967	$17,614	($37,471,064)	$269,471,759	$40,548,307	$2,788,838	($5,896,513)	$32,032,353	$303,667,261
Sink Total	$252,897,946	$2,633,208	$525,386,300	$779,381,049	$56,159,378	$95,352,101	$68,847,201	$98,681,851	$1,879,339,033

Table 13-38 shows the profit per MWh by source and sink node type in the first 10 months of the 2025/2026 planning period. The sink total row represents the average profit per MWh of FTRs that have the same sink type. The source total column shows the average profit per MWh of FTRs that have the same source type. Hub to EHV Aggregate FTRs had the highest profit per MWh, $6.13 per MWh. Residual Metered Aggregate to EHV Aggregate FTRs had the largest loss per MWh, -$4.19 per MWh. Profit per MWh of generator to generator FTRs was $0.21 per MWh, below the market average of $0.33 per MWh.

Table 13-38 Profit per MWh by node type matrix: June through March, 2025/2026

	Sink Type								
Source Type	Aggregate	EHVAGG	Generator	Hub	Interface	Load	Residual Metered Aggregate	Zone	Source Total
Aggregate	($0.07)	$0.50	($0.03)	$0.34	$0.37	($0.15)	$0.17	$0.02	($0.02)
EHVAGG	$0.80	$0.50	$1.43	$1.11	$0.14	$1.23	$1.09	$0.16	$1.04
Generator	$0.66	$0.82	$0.21	$1.51	$0.55	$0.29	$0.77	$0.83	$0.36
Hub	($0.67)	$6.13	$0.42	$4.78	($1.95)	$0.75	$0.55	($0.91)	$0.43
Interface	($0.10)	($0.33)	($0.73)	$1.82	$1.10	$4.89	$1.32	($1.11)	($0.36)
Load	$0.07	($1.15)	($0.03)	$0.37	$0.19	$0.08	($0.04)	$0.03	$0.05
Residual Metered Aggregate	($0.04)	($4.19)	($0.41)	($0.55)	($0.21)	$0.28	$1.42	$0.13	($0.24)
Zone	$0.10	$1.18	($0.58)	$3.74	$2.50	$1.12	($0.14)	$0.28	$0.91
Sink Total	$0.47	$0.12	$0.15	$2.70	$0.81	$0.15	$0.43	$0.17	$0.33

Table 13-39 shows the top 20 source and sink node type pairs by MWh in the first 10 months of the 2025/2026 planning period. Table 13-39 compares settled MWh, profit and target credit of FTRs whose source and sink nodes are in different zones (across zones) with whose source and sink nodes are in the same zone (within a zone). The percentage shown under MWh column represents the proportion of FTRs that are within a zone and across zones for each source and sink node type pair. For example, 18.2 percent of generator to generator FTRs had source and sink nodes located in different zones, while 81.8 percent of generator to generator FTRs had source and sink nodes that are in the same zone. Generator to generator FTRs receive greater profits when they are within a zone than when they are across zones, while across zone generator to generator FTRs receive slightly greater target allocation credit.

Table 13-39 FTR MWh, Profit and Target Credit from inside a zone and across zones by top 20 source and sink node type

		MWh				Profit		Target Credit	
Source Type	Sink Type	Across Zones	Within a Zone	Across Zones	Within a Zone	Across Zones	Within a Zone	Across Zones	Within a Zone
Generator	Generator	513,037,128	2,311,904,711	18.2%	81.8%	$268,766,270	$317,642,046	$373,741,419	$318,257,962
Load	Load	33,741,096	460,862,690	6.8%	93.2%	($21,935,036)	$62,738,085	($25,521,253)	$99,339,564
Generator	Aggregate	97,023,943	310,068,017	23.8%	76.2%	$90,421,198	$176,644,818	$109,356,405	$197,345,561
Aggregate	Generator	72,703,250	236,384,315	23.5%	76.5%	($45,813,221)	$36,899,168	($47,992,467)	$36,578,939
Generator	Zone	55,890,477	217,342,884	20.5%	79.5%	$59,899,935	$166,411,363	$106,279,951	$310,432,424
Hub	Zone	158,678,011	16,589,246	90.5%	9.5%	($155,073,561)	($4,445,317)	($322,251,275)	($4,889,903)
Generator	Hub	67,947,187	74,703,945	47.6%	52.4%	$173,011,462	$42,210,329	$339,644,612	$65,857,172
Generator	Load	17,812,270	104,032,820	14.6%	85.4%	($652,441)	$35,619,905	$19,983,725	$76,213,424
Zone	Zone	114,128,915		100.0%		$32,032,353		$144,018,406	
Load	Generator	12,186,483	87,083,708	12.3%	87.7%	($2,354,187)	($983,278)	($9,983,548)	($13,649,827)
Generator	Residual Metered Aggregate	15,636,461	57,278,892	21.4%	78.6%	$15,820,255	$40,297,678	$31,641,302	$54,454,615
Zone	Hub	70,524,564	1,559,387	97.8%	2.2%	$269,232,816	$238,944	$658,682,410	$204,221
Aggregate	Aggregate	11,022,040	54,849,419	16.7%	83.3%	$3,284,201	($7,991,574)	$1,637,550	($11,568,852)
Zone	Generator	22,680,097	41,947,239	35.1%	64.9%	$5,881,664	($43,352,728)	($1,291,558)	($59,430,546)
Hub	Hub	18,777,944	41,820,492	31.0%	69.0%	$123,019,359	$166,934,593	$198,615,503	$249,181,829
Residual Metered Aggregate	Generator	17,410,106	35,349,682	33.0%	67.0%	($5,159,063)	($16,557,272)	($16,755,055)	($31,297,579)
Zone	Residual Metered Aggregate	422,526	42,054,048	1.0%	99.0%	$589,115	($6,485,628)	$957,883	($8,467,197)
Generator	Interface	22,478,742	19,181,194	54.0%	46.0%	$24,462,653	($1,450,749)	$45,166,236	$429,829
Hub	Generator	13,209,004	18,620,695	41.5%	58.5%	$4,003,855	$9,522,010	($874,926)	$7,321,559
Aggregate	Zone	3,698,387	18,617,795	16.6%	83.4%	($3,835,218)	$4,334,244	($383,161)	$9,576,432

Revenue

Long Term FTR Auction Revenue

Table 13-40 shows the Long Term FTR Auction revenue data by trade type, FTR direction, period type and class type. The 2025/2028 Long Term FTR Auction netted $162,279,258 million in revenue, $59,642,543 million less (58.1 percent) than the previous Long Term FTR Auction. Buyers paid $276,421,108 million, up $86.7 million (45.7 percent), and sellers received $114,141,850 million, up $27.1 million (31.1 percent) over the previous Long Term FTR Auction.

Annual FTR Auction Revenue

Table 13-41 shows the Annual FTR Auction revenue by trade type, type, FTR direction and class type. The Annual FTR Auction for the 2025/2026 planning period generated $1,895.3 million, up 28.5 percent from $1,475.3 million in the 2024/2025 Annual FTR Auction. Counter flow FTR holders received $701.0 million, up 116.8 percent from the previous Annual FTR Auction and prevailing flow FTR holders paid $2,596.4 million, up 44.4 percent from the previous planning period.

Table 13-40 Long Term FTR Auction Revenue: 2025/2028 auction

			Class Type				
Trade Type	FTR Direction	Period Type	24-Hour	On Peak	Weekend On Peak	Daily Off Peak	All
Buy bids	Counter Flow	Year 1	($187,909,984)	($216,963,118)	($64,608,262)	($67,215,408)	($536,696,773)
		Year 2	($80,728,121)	($146,341,601)	($44,179,335)	($53,862,609)	($325,111,666)
		Year 3	($70,360,632)	($159,733,337)	($43,905,537)	($60,395,562)	($334,395,068)
		Total	($338,998,737)	($523,038,056)	($152,693,134)	($181,473,579)	($1,196,203,506)
	Prevailing Flow	Year 1	$184,712,464	$298,658,914	$88,488,683	$89,254,850	$661,114,911
		Year 2	$142,914,374	$168,975,183	$49,503,854	$59,268,382	$420,661,792
		Year 3	$150,371,570	$148,848,595	$38,892,667	$52,735,079	$390,847,911
		Total	$477,998,407	$616,482,692	$176,885,204	$201,258,311	$1,472,624,614
	Total		$138,999,670	$93,444,636	$24,192,070	$19,784,732	$276,421,108
Sell offers	Counter Flow	Year 1	($2,959,644)	($50,360,324)	($13,442,689)	($16,488,436)	($83,251,094)
		Year 2	($1,189,086)	($23,147,648)	($7,132,432)	($7,127,277)	($38,596,441)
		Year 3	($113,923)	($10,445,499)	($2,492,898)	($2,851,597)	($15,903,917)
		Total	($4,262,653)	($83,953,471)	($23,068,019)	($26,467,309)	($137,751,452)
	Prevailing Flow	Year 1	$8,788,063	$85,144,620	$21,508,078	$28,247,333	$143,688,093
		Year 2	$8,128,977	$44,380,646	$12,867,821	$20,932,602	$86,310,046
		Year 3	$1,369,541	$10,544,270	$3,079,649	$6,901,703	$21,895,163
		Total	$18,286,581	$140,069,535	$37,455,548	$56,081,638	$251,893,302
	Total		$14,023,929	$56,116,064	$14,387,529	$29,614,328	$114,141,850
Total			$124,975,741	$37,328,572	$9,804,541	($9,829,596)	$162,279,258

Table 13-41 Annual FTR auction revenue: 2025/2026 planning period

			Class Type				
Trade Type	Type	FTR Direction	24-Hour	On Peak	Weekend On Peak	Daily Off Peak	All
Buy bids	Obligations	Counter Flow	($99,152,385)	($481,420,630)	($136,052,349)	($156,244,140)	($872,869,504)
		Prevailing Flow	$498,216,463	$933,963,451	$261,323,797	$274,545,181	$1,968,048,892
		Total	$399,064,078	$452,542,820	$125,271,448	$118,301,041	$1,095,179,388
	Options	Counter Flow	$0	$0	$0	$0	$0
		Prevailing Flow	$16,561,879	$90,735,513	$29,938,410	$31,215,684	$168,451,486
		Total	$16,561,879	$90,735,513	$29,938,410	$31,215,684	$168,451,486
	Total	Counter Flow	($99,152,385)	($481,420,630)	($136,052,349)	($156,244,140)	($872,869,504)
		Prevailing Flow	$514,778,342	$1,024,698,964	$291,262,207	$305,760,865	$2,136,500,378
		Total	$415,625,957	$543,278,334	$155,209,858	$149,516,725	$1,263,630,873
Self-scheduled bids	Obligations	Counter Flow	($101,575)	$0	$0	$0	($101,575)
		Prevailing Flow	$735,751,303	$10,786,097	$2,660,019	$2,483,928	$751,681,346
		Total	$735,649,727	$10,786,097	$2,660,019	$2,483,928	$751,579,771
Buy and self-scheduled bids	Obligations	Counter Flow	($99,253,960)	($481,420,630)	($136,052,349)	($156,244,140)	($872,971,080)
		Prevailing Flow	$1,233,967,766	$944,749,547	$263,983,816	$277,029,109	$2,719,730,238
		Total	$1,134,713,806	$463,328,917	$127,931,467	$120,784,969	$1,846,759,158
	Options	Counter Flow	$0	$0	$0	$0	$0
		Prevailing Flow	$16,561,879	$90,735,513	$29,938,410	$31,215,684	$168,451,486
		Total	$16,561,879	$90,735,513	$29,938,410	$31,215,684	$168,451,486
	Total	Counter Flow	($99,253,960)	($481,420,630)	($136,052,349)	($156,244,140)	($872,971,080)
		Prevailing Flow	$1,250,529,644	$1,035,485,060	$293,922,226	$308,244,793	$2,888,181,724
		Total	$1,151,275,684	$554,064,430	$157,869,877	$152,000,653	$2,015,210,644
Sell offers	Obligations	Counter Flow	($33,651,501)	($84,515,741)	($26,247,005)	($27,513,050)	($171,927,297)
		Prevailing Flow	$44,057,528	$148,292,408	$42,217,276	$53,983,613	$288,550,825
		Total	$10,406,026	$63,776,667	$15,970,271	$26,470,563	$116,623,528
	Options	Counter Flow	$0	$0	$0	$0	$0
		Prevailing Flow	$430,953	$1,591,432	$731,895	$515,750	$3,270,030
		Total	$430,953	$1,591,432	$731,895	$515,750	$3,270,030
	Total	Counter Flow	($33,651,501)	($84,515,741)	($26,247,005)	($27,513,050)	($171,927,297)
		Prevailing Flow	$44,488,481	$149,883,840	$42,949,171	$54,499,363	$291,820,855
		Total	$10,836,979	$65,368,099	$16,702,166	$26,986,313	$119,893,558
Total			$1,140,438,705	$488,696,331	$141,167,711	$125,014,340	$1,895,317,086

FTRs sold in Long Term FTR Auctions are sold at a substantial discount to the same FTRs sold in Annual FTR Auctions. Table 13-42 shows the increase in total auction revenue that would have resulted for the 2014/2015 through 2025/2026 planning periods if long term FTRs were sold at annual auction clearing prices.

Long Term FTR Auction MW are determined by removing all outages and running an offline model of the previous Annual FTR Auction model with all ARR bids from the prior annual ARR allocation. Any ARR MW that clear in this offline model are reserved for ARR holders in the relevant planning periods, and are removed from the Long Term FTR Auction. But even this approach does not, and cannot, preserve all the capacity for ARR holders in the first year of the Long Term Auction. The MW purchased in the Long Term FTR Auction are made available to FTR holders before ARR holders have access to them. The result is that MW are reserved, inappropriately and for unexplained reasons, in future auctions for FTR holders. This difference provides an estimate of the value of the MW made available in the Long Term FTR Auction that are not made available to ARR holders. These MW should be made available to ARR holders in the Annual FTR Auctions where they are the most valuable. Under the current market rules, MW made available in the Long Term FTR auction are not available to ARR holders as ARRs. 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, and not projected residual system capability based on a snapshot of prior ARR requests.

Table 13-42 Estimated additional Long Term FTR Auction revenue at Annual FTR Auction prices

	Long Term FTR Product				
Planning Period	YR3	YR2	YR1	YRALL	Total Difference
2014/2015	$59,598,642	$30,284,173	$52,030,909	$926,989	$142,840,713
2015/2016	$67,896,588	$40,975,278	$9,936,078	$303,082	$119,111,026
2016/2017	$42,378,048	$3,854,373	$11,055,824	$1,079,901	$58,368,147
2017/2018	$6,134,076	($1,841,715)	$12,396,817	$227,524	$16,916,702
2018/2019	$7,872,604	$2,926,457	$13,480,353	($111,226)	$24,168,189
2019/2020	$9,711,188	$4,098,887	$103,227,004	$805,425	$117,842,504
2020/2021	($416,585)	$52,736,819	($9,690,808)	$1,242,707	$43,872,132
2021/2022	$73,050,796	($3,111,721)	$13,856,264	NA	$83,795,339
2022/2023	$42,759,622	$62,664,762	$104,025,268	NA	$209,449,652
2023/2024	$45,464,085	$31,335,632	$39,140,382	NA	$115,940,099
2024/2025	$42,500,160	$23,979,155	$36,720,756	NA	$103,200,071
2025/2026	$100,410,553	$68,518,553	$93,705,408	NA	$262,634,514
Total	$497,359,776	$316,420,654	$479,884,255	$4,474,401	$1,298,139,087

Monthly Balance of Planning Period FTR Auction Revenue

Table 13-43 shows monthly balance of planning period FTR auction revenue by trade type, type and class type for the first ten months of the 2025/2026 and the entire 2024/2025 planning periods. The Monthly Balance of Planning Period FTR Auctions for the first ten months of the 2025/2026 planning period netted $88.7 million in revenue, the difference between buyers paying $977.0 million and sellers receiving $888.3 million. For the entire 2024/2025 planning period, the Monthly Balance of Planning Period FTR Auctions netted $79.6 million in revenue with buyers paying $671.2 million and sellers receiving $591.6 million.

Revenue from obligation buy bids for the first ten months of the 2025/2026 planning period was $850.4 million, up 54.2 percent compared to the same period of the 2024/2025 planning period. Expenditure from obligation sell offers in the first ten months of the 2025/2026 planning period was $606.9 million, up 48.9 percent compared to the same period of the 2024/2025 planning period.

Table 13-43 Monthly Balance of Planning Period FTR Auction revenue: 2024/2025 and 2025/2026 planning period

			Class Type				
Monthly Auction	Type	Trade Type	24-Hour	On Peak	Daily Off Peak	Weekend On Peak	All
Jun-25	Obligations	Buy bids	$43,963,789	$59,550,615	$11,244,539	$17,818,883	$132,577,826
		Sell offers	$10,807,119	$53,694,995	$13,744,740	$17,282,983	$95,529,837
	Options	Buy bids	$232,202	$8,861,467	$4,007,673	$2,867,090	$15,968,432
		Sell offers	$2,969,446	$21,150,179	$5,658,918	$6,780,519	$36,559,061
Jul-25	Obligations	Buy bids	$11,769,736	$47,782,060	$10,707,639	$14,767,032	$85,026,467
		Sell offers	$3,763,947	$38,944,621	$8,273,644	$11,761,740	$62,743,951
	Options	Buy bids	$2,132,213	$7,568,007	$3,473,035	$2,743,547	$15,916,801
		Sell offers	$2,703,871	$19,837,413	$4,823,689	$6,517,948	$33,882,921
Aug-25	Obligations	Buy bids	($346,749)	$50,008,965	$12,464,614	$16,378,232	$78,505,063
		Sell offers	$2,897,894	$31,862,957	$7,672,652	$11,359,638	$53,793,141
	Options	Buy bids	$534,023	$7,479,258	$3,559,637	$2,734,285	$14,307,204
		Sell offers	$2,638,486	$16,477,506	$4,647,661	$5,396,476	$29,160,129
Sep-25	Obligations	Buy bids	($3,169,946)	$54,069,302	$21,118,313	$17,242,156	$89,259,824
		Sell offers	$21,189,710	$31,183,579	$9,973,679	$9,419,961	$71,766,929
	Options	Buy bids	$834,043	$8,840,903	$3,789,646	$3,408,415	$16,873,008
		Sell offers	$2,077,559	$13,173,571	$5,452,261	$4,425,345	$25,128,736
Oct-25	Obligations	Buy bids	$330,610	$43,891,284	$17,587,815	$14,819,286	$76,628,996
		Sell offers	$12,291,500	$26,016,645	$9,932,175	$8,807,709	$57,048,028
	Options	Buy bids	$1,689,799	$5,748,664	$2,178,939	$2,512,539	$12,129,941
		Sell offers	$2,072,980	$13,144,149	$5,294,750	$4,034,201	$24,546,080
Nov-25	Obligations	Buy bids	($5,040,920)	$41,152,793	$16,577,605	$13,569,145	$66,258,623
		Sell offers	$2,767,144	$25,702,926	$9,650,692	$7,604,093	$45,724,856
	Options	Buy bids	$704,949	$6,399,585	$2,215,866	$2,324,471	$11,644,870
		Sell offers	$2,217,435	$12,046,857	$5,757,145	$4,698,133	$24,719,571
Dec-25	Obligations	Buy bids	$17,174,878	$45,620,898	$21,025,928	$13,605,325	$97,427,029
		Sell offers	$1,636,246	$40,254,138	$22,675,021	$12,666,371	$77,231,776
	Options	Buy bids	$1,426,323	$5,683,516	$5,390,206	$1,828,956	$14,329,001
		Sell offers	$2,588,420	$15,439,317	$7,558,590	$4,738,373	$30,324,700
Jan-26	Obligations	Buy bids	$10,031,185	$41,953,890	$21,539,613	$12,597,073	$86,121,761
		Sell offers	$5,487,761	$31,303,225	$16,049,555	$9,817,400	$62,657,941
	Options	Buy bids	$2,011,390	$4,538,922	$1,488,891	$1,704,839	$9,744,042
		Sell offers	$2,525,857	$15,498,004	$6,760,423	$4,876,000	$29,660,284
Feb-26	Obligations	Buy bids	$6,980,665	$36,505,375	$17,095,518	$9,638,334	$70,219,892
		Sell offers	$2,533,267	$25,283,956	$11,674,650	$6,511,547	$46,003,420
	Options	Buy bids	$3,052,488	$3,992,532	$1,113,211	$1,485,475	$9,643,706
		Sell offers	$2,179,795	$12,744,346	$5,952,647	$3,724,270	$24,601,058
Mar-26	Obligations	Buy bids	$18,511,237	$30,503,023	$10,261,086	$9,067,463	$68,342,810
		Sell offers	$1,034,993	$19,890,696	$7,029,680	$6,463,036	$34,418,404
	Options	Buy bids	$1,512,121	$2,606,457	$1,173,685	$773,654	$6,065,917
		Sell offers	$2,046,360	$12,012,123	$5,006,854	$3,714,733	$22,780,070
2024/2025*	Obligations	Buy bids	$92,291,775	$334,508,875	$87,723,212	$82,618,475	$597,142,337
		Sell offers	$24,741,555	$270,347,683	$73,133,231	$67,754,244	$435,976,713
	Options	Buy bids	$16,363,731	$31,182,988	$14,530,149	$11,936,121	$74,012,989
		Sell offers	$19,034,193	$80,149,449	$30,035,406	$26,381,757	$155,600,805
	Net Total		$64,879,758	$15,194,731	($915,277)	$418,596	$79,577,808
2025/2026**	Obligations	Buy bids	$100,204,485	$451,038,205	$159,622,671	$139,502,931	$850,368,292
		Sell offers	$64,409,580	$324,137,738	$116,676,488	$10x1,694,477	$606,918,284
	Options	Buy bids	$14,129,550	$61,719,310	$28,390,790	$22,383,271	$126,622,921
		Sell offers	$24,020,209	$151,523,464	$56,912,938	$48,905,999	$281,362,610
	Net Total		$25,904,245	$37,096,313	$14,424,034	$11,285,726	$88,710,318

*Shows twelve months for 2024/2025 **Shows ten months for 2025/2026

Table 13-44 shows the monthly balance of planning period FTR auction revenue by FTR direction and trade type for FTRs effective in each month. For example, June 2025 shows FTR auction revenue for FTRs that are effective in June that were sold in the June 2025 Auction. July 2025 shows FTR auction revenue for FTRs that are effective in July that were sold in the June 2025 Auction and the July 2025 Auction. Table 13-44 also shows the monthly Residual ARR target allocations. Residual ARR target allocations in a month should be fully funded by FTR auction revenue from FTRs that are effective in the same month.

Auction revenue from monthly FTRs effective in the first ten months of the 2025/2026 planning period was $71.3 million, up 13.9 percent from $62.6 million in the same period of the 2024/2025 planning period. However, Residual ARR target allocations in the first ten months of the 2025/2026 planning period were $76.0 million, up 243.9 percent from $22.1 million in the same period of the 2024/2025 planning period.

While total auction revenue from monthly FTRs effective in the first ten months of the 2025/2026 planning period was up 13.9 percent, the results by FTR direction (prevailing versus counterflow) and by trade type (buy versus sell) were different. Negative auction revenue from buy bids for counter flow FTRs effective in the first ten months of the 2025/2026 planning period was $981.6 million, up 67.5 percent from $586.2 million in the same period of the 2024/2025 planning period. Positive auction revenue from sell bids for counter flow FTRs effective in the first ten months of the 2025/2026 planning period was $438.7 million, up 103.8 percent from $215.3 million in the same period of the 2024/2025 planning period. Positive auction revenue from buy bids for prevailing flow FTRs effective in the first ten months of the 2025/2026 planning period was $1,766.2, up 59.6 percent from $1,106.5 in the same period of the 2024/2025 planning period. Negative auction revenue from sell bids for prevailing flow FTRs effective in the first ten months of the 2025/2026 planning period was $1,152.0 million, up 71.2 percent from $479.1 million in the same period of the 2024/2025 planning period. The large increase in both residual ARR target allocations and negative auction revenue from counter flow FTRs effective in the first three months of the planning period contributed to the first ARR deficiency in the history of the ARR market in July 2025 (See Table 13-10). If PJM had sold fewer counter flow FTRs effective in July 2025, there would not have been an ARR deficiency. Residual ARR target allocations decreased following the highs in June 2025, July 2025, and August 2025 and revenue from FTR sell bids for counterflow increased, preventing another ARR deficiency from occurring.

Table 13-44 Monthly Balance of Planning Period FTR Auction revenue by FTR period compared to Residual ARR target allocations: 2024/2025 and 2025/2026

	Revenue From Monthly FTR Auctions By Period					
Month	Counter Flow Buy Bids	Counter Flow Sell Bids	Prevailing Flow Buy Bids	Prevailing Flow Sell Bids	All	Residual ARR Target Allocations
Jun-24	($12,935,096)	$6,463,400	$30,668,516	($21,035,151)	$3,161,668	$1,542,269
Jul-24	($27,907,987)	$12,672,303	$62,067,006	($42,200,251)	$4,631,071	$817,746
Aug-24	($35,671,626)	$17,132,476	$88,169,309	($63,820,383)	$5,809,776	$2,192,686
Sep-24	($47,035,465)	$17,030,440	$95,463,590	($59,958,680)	$5,499,885	$940,983
Oct-24	($61,463,190)	$22,257,984	$113,529,086	($66,887,221)	$7,436,660	$675,276
Nov-24	($57,049,350)	$21,841,656	$110,922,641	($68,430,428)	$7,284,518	$389,592
Dec-24	($73,445,957)	$24,806,231	$127,502,478	($71,230,090)	$7,632,662	$1,423,964
Jan-25	($96,757,094)	$33,228,566	$172,405,984	($101,741,615)	$7,135,841	$3,351,831
Feb-25	($94,081,134)	$32,261,091	$164,140,690	($95,141,385)	$7,179,262	$9,503,030
Mar-25	($79,877,699)	$27,581,488	$141,629,663	($82,498,441)	$6,835,012	$1,258,883
Apr-25	($88,162,518)	$29,973,301	$158,981,445	($92,626,958)	$8,165,270	$3,845,490
May-25	($99,848,832)	$31,544,129	$179,910,865	($102,799,980)	$8,806,182	$367,497
	Summary For Planning Period 2024/2025					
Total	($774,235,947)	$276,793,065	$1,445,391,273	($868,370,583)	$79,577,808	$26,309,246
Jun-25	($25,629,760)	$11,335,282	$51,618,952	($35,385,606)	$1,938,869	$12,903,832
Jul-25	($61,853,731)	$22,288,524	$111,168,475	($66,648,525)	$4,954,744	$23,175,461
Aug-25	($73,536,354)	$29,025,252	$133,268,414	($83,203,970)	$5,553,342	$13,502,528
Sep-25	($80,532,210)	$29,608,604	$141,134,731	($84,519,169)	$5,691,956	$952,098
Oct-25	($92,124,081)	$31,856,580	$162,569,433	($96,398,953)	$5,902,980	$4,658,518
Nov-25	($92,700,403)	$36,268,021	$163,026,687	($101,001,852)	$5,592,453	$5,780,545
Dec-25	($113,946,473)	$52,799,488	$208,682,619	($144,748,264)	$2,787,369	$1,556,605
Jan-26	($157,236,107)	$77,332,765	$273,466,286	($187,410,024)	$6,152,920	$6,173,623
Feb-26	($136,508,092)	$67,099,802	$249,730,898	($168,310,949)	$12,011,659	$2,951,786
Mar-26	($147,508,420)	$81,108,186	$271,571,444	($184,411,703)	$20,759,507	$4,313,687
	Summary For Planning Period 2025/2026*					
Total	($981,575,630)	$438,722,504	$1,766,237,940	($1,152,039,014)	$71,345,800	75,968,684.33

*First ten months of the 2025/2026 planning period

FTR Target Allocations

FTR target allocations were examined separately by source and sink contribution. Hourly FTR target allocations were divided into those that were benefits and liabilities and summed by sink and by source. Figure 13-11 shows the 10 largest positive and negative FTR target allocations, summed by sink, for the first ten months of the 2025/2026 planning period. The top 10 sinks that produced financial benefit accounted for 22.0 percent of total positive target allocations with Western Hub accounting for 9.0 percent of all positive target allocations. The top 10 sinks that created liability accounted for 13.6 percent of total negative target allocations with PPL accounting for 2.3 percent of all negative target allocations.

Figure 13-11 Ten largest positive and negative FTR target allocations summed by sink: June through March, 2025/2026[44]

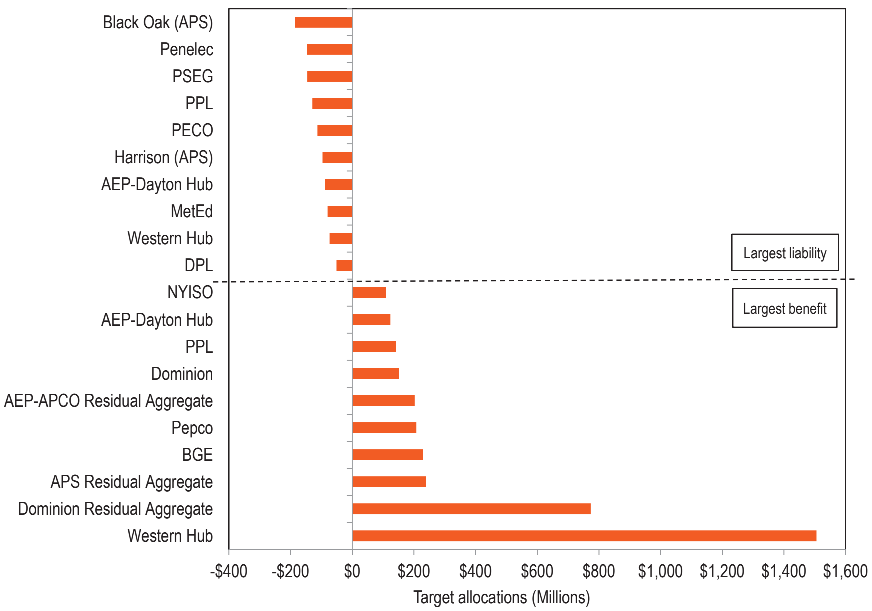
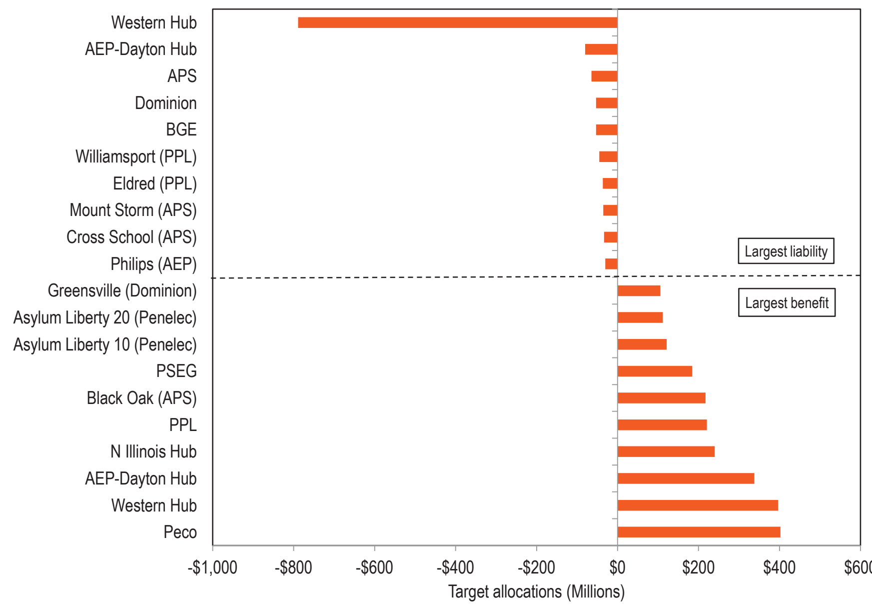


Figure 13-12 shows the 10 largest positive and negative FTR target allocations, summed by source, for the first ten months of the 2025/2026 planning period. The top 10 sources with a positive target allocation accounted for 14.0 percent of total positive target allocations with PECO accounting for 2.4 percent of total positive target allocations. The top 10 sources with a negative target allocation accounted for 15.0 percent of all negative target allocations, with the Western Hub accounting for 9.7 percent of total negative target allocations.

Figure 13-12 Ten largest positive and negative FTR target allocations summed by source: June through March, 2025/2026[45]



The Effect of Fast Start Pricing on FTR Target Allocations

PJM implemented fast start pricing on September 1, 2021, and as a result, PJM produces separate dispatch and pricing market solutions. The dispatch run results in dispatch instructions and matching prices, termed dispatch run locational marginal prices, or DLMP. The DLMP prices are the prices that would have been the LMPs prior to fast start pricing. The pricing run results in the final prices used in settlements and for FTR target allocations, termed pricing run locational marginal prices, or PLMP. The two runs result in different sets of target allocations for the same FTR paths. Table 13-45 compares the target allocations that result from the pricing and dispatch runs for both self scheduled and all other FTRs for the 2021/2022 planning period through the first ten months of the 2025/2026 planning period. The difference indicates

44 This figure is affected by the identified distribution factor error.

45 This figure is affected by the identified distribution factor error.

whether the target allocations were increased or decreased as a result of fast start pricing.

Table 13-45 Pricing run and dispatch run FTR Target Allocations: 2021/2022 through 2025/2026 planning periods[46]

Planning Period		Pricing Run	Dispatch Run	Difference	Percent Difference
2021/2022*	Not Self Scheduled	$1,499,077,738	$1,497,963,895	$1,113,844	0.1%
	Self Scheduled	$429,271,338	$430,800,598	($1,529,260)	(0.4%)
	Total	$1,928,349,076	$1,928,764,493	($415,416)	(0.0%)
2022/2023	Not Self Scheduled	$1,641,324,421	$1,586,284,502	$55,039,919	3.4%
	Self Scheduled	$622,535,802	$668,468,552	($45,932,751)	(7.4%)
	Total	$2,263,860,223	$2,254,753,054	$9,107,169	0.4%
2023/2024	Not Self Scheduled	$1,396,273,015	$1,435,733,398	($39,460,383)	(2.8%)
	Self Scheduled	$371,433,164	$371,620,633	($187,469)	(0.1%)
	Total	$1,767,706,179	$1,807,354,031	($39,647,853)	(2.2%)
2024/2025	Not Self Scheduled	$2,077,018,180	$2,088,851,413	($11,833,233)	(0.6%)
	Self Scheduled	$657,847,842	$660,668,360	($2,820,518)	(0.4%)
	Total	$2,734,866,022	$2,749,519,773	($14,653,751)	(0.5%)
2025/2026**	Not Self Scheduled	$3,028,002,161	$3,358,950,420	($330,948,259)	(10.9%)
	Self Scheduled	$1,262,339,078	$1,386,344,128	($124,005,050)	(9.8%)
	Total	$4,290,341,239	$4,745,294,548	($454,953,309)	(10.6%)

* starting in September 2021

** first ten months of the 2025/2026 planning period

Surplus Congestion Revenue

Surplus congestion revenue is a misnomer. There is no such thing as surplus congestion revenue. The rights to all congestion revenue belong to load. Surplus congestion revenue, as defined in PJM rules, is an artifact of the flawed design of the current approach to FTR/ARRs. In the current design, surplus congestion revenue should be allocated to ARR holders because such revenue is part of total congestion revenues.

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 who are the sellers, and should not be returned to FTR buyers for any reason.

Under the existing PJM rules, surplus day-ahead congestion is defined as the difference between the day-ahead congestion paid and FTR target allocations. Under the existing PJM rules, surplus FTR auction revenue is defined as the difference between the sum of monthly FTR auction revenue from the Long Term, Annual and monthly auctions, and ARR target allocations. Surplus FTR auction revenue can result from high prices in the FTR auctions, and from FTR capacity sold in excess of assigned ARR capacity on specific paths, and FTR capacity sold on paths not available to ARR holders.

Under the existing PJM rules, surplus congestion revenue is defined as the sum of the surplus day-ahead congestion revenue and the surplus FTR auction revenue at the end of each month.[47] Beginning with the 2014/2015 planning period, PJM may use surplus FTR auction revenue to pay for the clearing of counter flow FTRs as part of the auction clearing process.[48] The remaining surplus is first used to ensure that ARR target allocations in the month are fully funded. Any remaining surplus is used to pay any negative difference between day-ahead congestion revenue and FTR target allocations for the current month or prior months in the planning period. Any remaining surplus is used to pay any negative difference between day-ahead congestion revenue and FTR target allocations for the entire planning period at the end of the planning period. Any remaining surplus after that is distributed to ARR holders.[49]

If, at the end of the planning period, all the surplus congestion revenue has been provided to FTR holders and target allocations for the year are not covered, an uplift charge is assigned to FTR holders to cover the net planning period deficiency. An individual participant's uplift charge allocation is the ratio of their share of net positive target allocations to the total net positive target allocations.

Figure 13-13 shows the monthly composition of total surplus, by surplus FTR auction revenue and surplus congestion revenue from June 2017 through

46 This table is affected by the identified distribution factor error.

47 Prior to the 2017/2018 planning period, the surplus congestion revenue was not the simple sum of the surplus FTR auction revenue and surplus day-ahead congestion because there were various cross market charges subtracted from FTR revenue, including M2M and competing use charges, which reduced available surplus congestion revenue.

48 *See* "PJM Manual 6: Financial Transmission Rights," Rev. 34 (May 21, 2025).

49 On May 31, 2018, a rule change was implemented. Effective for the 2018/2019 planning period, surplus day-ahead congestion charges and surplus FTR auction revenue that remain at the end of the Planning Period allocated to ARR holders, rather than to FTR holders. 163 FERC ¶ 61,165 (2018).

March 2026 as if FTRs were settled monthly, based on the congestion and FTR auction revenue in each individual month. In only five of the first ten months of the 2025/2026 planning period (June, July, October, January, and February) was the day ahead congestion in that month alone enough to pay FTR target allocations for the month. In July 2025 there was no auction surplus and ARR holders were not paid the full target allocations for the month. Months with ARR deficiencies will be funded at the end of the planning period from surplus FTR revenues if there is an FTR surplus or through an uplift charge to FTR holders if there is not an FTR surplus. Figure 13-13 shows the extent to which FTRs are funded by the auction surplus. As part of the illogic of the FTR/ARR construct and as an illustration that it is unlike any actual market, FTR buyers pay ARR holders for the rights to congestion but FTR buyers may reclaim part of their payment if actual congestion is less than they expected and not enough to cover target allocations.

The market rules should recognize that ARR holders have the right to all surplus FTR auction revenue, not just the remainder after guaranteeing that FTRs are paid target allocations. The surplus FTR auction revenue results from the prices that FTR buyers willingly paid for the rights to price differences across specific paths. The MMU recommends that all FTR auction revenue be distributed to ARR holders monthly, regardless of FTR funding levels. 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. Under the MMU recommendation, the amount represented by each bar in Figure 13-14 would be assigned to ARR holders in every month.

Figure 13-13 Monthly surplus auction revenue and surplus congestion revenue: June 2017 through March 2026[50]

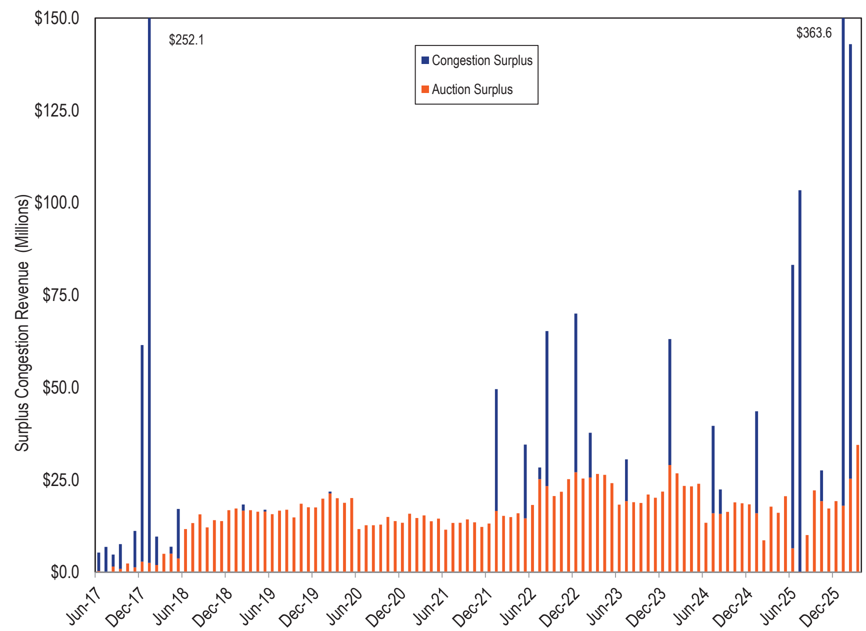


Figure 13-14 shows the increase or decrease in total accrued surplus for the planning period for each month (orange line). In Figure 13-14, if the FTR payments from the auction surplus are positive in a month (blue line above zero), that means that FTR payments in that month were dependent on FTR auction surplus from that month to cover the FTR target allocations in that month. If the change in the total accrued surplus for a month is positive, that means that there was surplus revenue (equal to the height of the orange bar) left over after paying FTR target allocations in that month from congestion or from auction revenue. This net surplus is carried until the end of the planning period and used to backfill FTR target allocations as needed before distributing to ARR holders. If the change in total accrued surplus for a month is negative, that means that were insufficient revenues, including the auction surplus, to

50 The bars for January 2018 and January 2026 are truncated.

pay FTR target allocations in that month. If the net surplus is negative at the end of the planning period, total revenue paid to FTRs will be lower than total FTR target allocations. Under the current rules, FTRs are made whole using surplus revenue from other months within the same planning period or by an uplift charge to all FTR holders at the end of the planning period. The final settlements are not known until the end of the planning period.

In the 2024/2025 planning period there was not enough revenue from congestion plus auction surplus to pay FTR target allocations, resulting in a reduction to the entire planning period surplus of $196.2 million. ARR holders were required to subsidize FTR holders because congestion revenues were less than FTR target allocations.

In the first ten months of the 2025/2026 planning period, there was enough congestion to pay FTR target allocations. However, due to the monthly settlement process $93.2 million of FTR auction revenue was transferred from ARR holders to FTR holders in individual months that did not have enough revenue from congestion to pay FTR target allocations. If congestion revenue remains higher than FTR target allocations at the end of the 2025/2026 planning period, the $93.2 million will be distributed back to ARR holders. If congestion revenue is less than FTR target allocations at the end of the 2025/2026 planning period, the $93.2 million will not be distributed back to ARR holders. Under the MMU's recommendation to distribute all FTR auction revenue to ARR holders every month, regardless of FTR funding levels, the $93.2 million of FTR auction revenue would have been paid to ARR holders in the month that it was collected by PJM and ARR holders would not be required to subsidize underperforming FTRs.

In the first ten months of the 2025/2026 planning period, day-ahead congestion increased by $2,733.8 million, 133.0 percent, from $744.0 million in the first ten months of the 2024/2025 planning period to $4,789.5 million in the first ten months of the 2025/2026 planning period. Target allocations increased by $2,291.2 million, 90.9 percent, from $833.4 million in the first ten months of the 2024/2025 planning period to $4,291.2 million in the first ten months of the 2025/2026 planning period. The actual day-ahead congestion ($4,789.5 million) was greater than the target allocations ($4,291.2 million) in the first ten months of the 2025/2026 planning period. In July 2025, there was a large increase in Residual ARR target allocations without a corresponding increase in Monthly FTR Auction revenue, resulting in the first month with an ARR deficiency in the history of the ARR market. This disconnect between the ARR and FTR markets is a result of the fact that congestion is incorrectly defined as target allocations, i.e. the property rights for congestion in the current ARR/FTR market design are not correctly defined.

Figure 13-14 Monthly ARR surplus: June 2017 through March 2026[51]

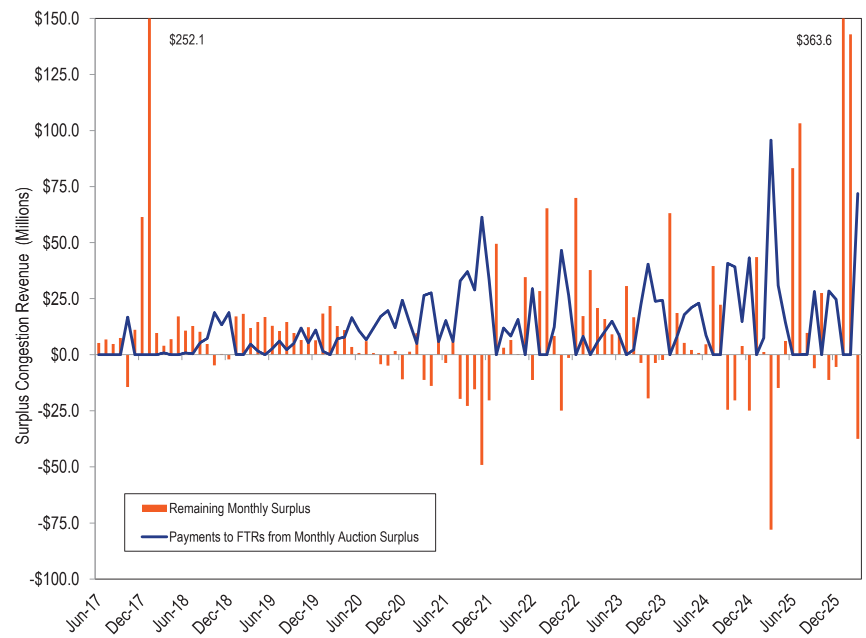


Figure 13-15 shows the surplus FTR auction revenue from the 2011/2012 planning period through the first ten months of the 2025/2026 planning period. Each new planning period introduces a new FTR model, including outages and PJM's discretionary adjustments for revenue adequacy. The differences in the assumptions in the market model can result in large differences in FTR auction surplus and ARR revenue from one planning period to another.

51 The bars for January 2018 and January 2026 are truncated.

Payments to FTRs have relied on payments from the surplus rather than from day-ahead congestion. The persistent mismatch between target allocations and day-ahead congestion and the use of the surplus are another illustration of the internal illogic and incoherence of the PJM FTR/ARR design.

FTR auction revenue is the value that FTR buyers assign to congestion rights that belong to ARR holders. There is no logical or market based reason to assign any part of that auction revenue back to the FTR buyers. It is inconsistent with the operation of a market that sellers are required to return some of the purchase price to buyers if the purchase is less profitable for buyers than expected. Auction revenue from the sale of FTRs should be distributed directly and completely to ARR holders.

Figure 13-15 Monthly FTR auction surplus: 2011/2012 through 2025/2026 planning period

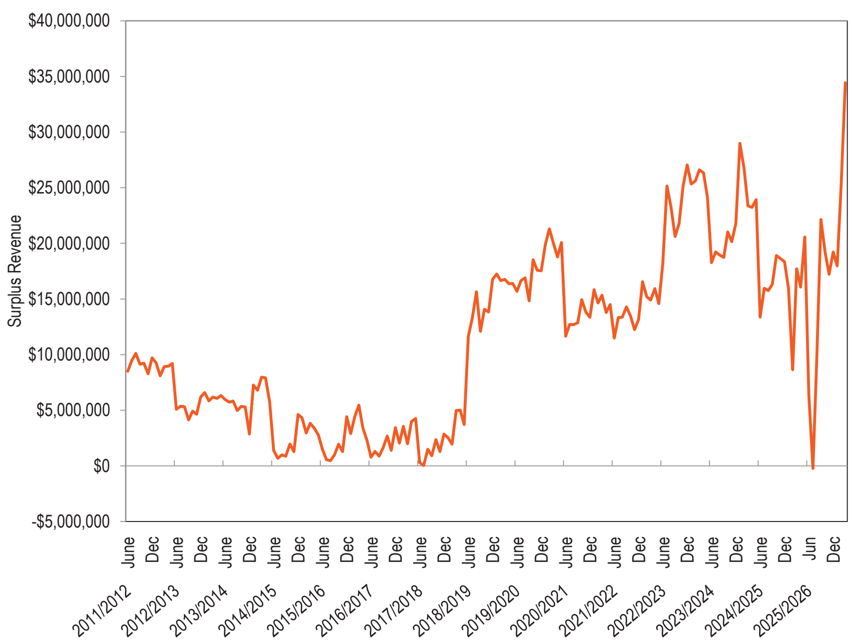


Table 13-46 shows the surplus FTR auction revenue, surplus day-ahead congestion revenue and surplus congestion revenue for planning periods 2010/2011 through the first ten months of the 2025/2026 planning period.

Table 13-46 Surplus FTR Auction Revenue: 2010/2011 through 2025/2026 planning period[52]

Planning Period	Surplus FTR Auction Revenue (Millions)	Surplus Day-Ahead Congestion (Millions)	Surplus Congestion Revenue (Millions)
2010/2011	$29.7	($1,218.7)	($449.3)
2011/2012	$108.9	($460.3)	($192.5)
2012/2013	$66.7	($328.5)	($292.3)
2013/2014	$71.7	($715.3)	($678.7)
2014/2015*	$29.0	$139.8	$139.6
2015/2016	$29.6	$56.4	$42.5
2016/2017	$27.9	$97.1	$72.6
2017/2018	$27.4	$344.0	$371.2
2018/2019	$180.8	($68.5)	$112.3
2019/2020	$217.8	($87.9)	$140.7
2020/2021	$166.1	($185.1)	($14.5)
2021/2022	$168.5	($198.0)	($29.5)
2022/2023	$289.2	($54.0)	$235.2
2023/2024	$264.4	($146.7)	$117.8
2024/2025	$196.2	($236.1)	($39.9)
2025/2026**	$171.8	$498.3	$670.0
Total	$2,045.8	($2,563.4)	$205.0

*Start of counter flow "buy back"

**First ten months of the 2025/2026 planning period

"Revenue Adequacy"

FTR revenue adequacy, like surplus congestion revenue, is a misnomer. FTR revenue adequacy, as defined in PJM rules, is an artifact of the flawed design of the current approach to FTR/ARRs. If FTRs only returned congestion to FTR holders, there could be no such thing as revenue inadequacy.

As currently defined in PJM, FTR revenue adequacy simply compares day-ahead congestion revenues to FTR target allocations. (Target allocations are the day-ahead CLMP differences, shadow prices, between the source and sink of the FTR times the MW of the FTR. Congestion revenues are the day-ahead

52 Total congestion surplus not equal to the sum of the columns in years prior to the 2017/2018 planning period because other charges were subtracted from the congestion surplus.

CLMP differences, shadow prices, between sources and sinks times the MW flow on the lines.) There is no reason to expect congestion revenues to equal FTR target allocations under the path based approach. There are systematic differences between FTR target allocations and actual congestion in aggregate and on a path by path basis. Revenue adequacy is not a benchmark for how well the FTR process is working. Target allocations are not congestion. FTR revenue adequacy is not equivalent to the adequacy of ARRs as an offset for load against total congestion. A path specific target allocation is not a guarantee of payment. Yet PJM treats target allocations as a guarantee of payment and takes what is termed surplus auction revenue from ARR holders (load) and gives it to FTR holders when day-ahead congestion revenues are not enough to cover all FTR target allocations.

Actual day-ahead congestion revenues are not a result of PJM's decisions about the FTR auction model, but result from the operation of the day-ahead energy market. As a result, the fewer FTRs sold, the higher the probability that congestion will exceed the sum of the FTR target allocations. For example, PJM's subjective decision to reduce available ARR/FTR supply in the ARR/FTR market model through outage selection for the 2014/2015 through 2016/2017 planning periods resulted in actual day-ahead congestion exceeding target allocations at the expense of a reduction in available ARRs and associated FTRs. PJM's decisions have included the arbitrary use of higher outage levels and the decision to include additional constraints (closed loop interfaces) both of which reduced the FTRs made available for sale in FTR auctions. PJM's actions have led to a significant reduction in the allocation of Stage 1B and Stage 2 ARRs and therefore a reduction in available FTRs.

PJM's arbitrary decision to increase outages in the ARR allocation and in the Annual FTR Auction did not address the Stage 1A ARR over allocation issue directly because Stage 1A ARR allocations cannot be prorated. Instead, PJM's actions for the 2014/2015 through 2016/2017 planning periods resulted in decreased Stage 1B ARR allocations, decreased Stage 2 ARR allocations and decreased FTR capability. The direct assignment of balancing congestion (generally negative) and M2M payments to load beginning in the 2017/2018 planning period arbitrarily decreased congestion available for load and increased the congestion revenue available to pay FTR holders. PJM reduced the number of outages taken in the ARR allocation and in the Annual FTR Auction, increasing the supply of ARRs and FTRs. The current ARR/FTR design does not serve as an efficient way to ensure that load receives all the congestion revenues or has the ability to receive the auction revenues associated with all the potential congestion revenues. There are several reasons for the disconnect between congestion revenues and ARR/FTR revenues in the current design. The reasons include: the use of generation to load paths rather than a measure of total congestion to assign congestion revenue rights; the failure to provide to ARR holders the full system capability that is provided to FTR purchasers in the Long Term FTR Auction; unavoidable modeling differences such as emergency outages; avoidable modeling differences such as outage modeling decisions; and cross subsidies among and between FTR participants and ARR holders.

Revenue adequacy for ARRs is, for practical purposes, a meaningless concept. Revenue adequacy for ARRs means that FTR buyers collectively pay more than zero for FTRs in FTR auctions, and that those payments were received by ARR holders. For that reason, ARRs have unsurprisingly been defined to be revenue adequate for every auction to date. ARR revenue adequacy has nothing to do with the adequacy of ARRs as an offset to total congestion. ARRs can be revenue adequate at the same time that ARRs return only half of congestion to load, or even much less.

Total net FTR auction revenue for the 2024/2025 planning period, before accounting for self scheduling, load shifts or residual ARRs, was $1,664.9 million. For the first ten months of the 2025/2026 planning period, total net FTR auction revenue from each FTR auction occurred was $2,137.0 million. Total ARR target allocations for the 2024/2025 planning period were $1,448.1 million. For the first ten months of the 2025/2026 planning period, ARR target allocations were $1,882.7 million.

Table 13-47 presents the PJM FTR revenue detail for the 2024/2025 planning period and the first ten months of the 2025/2026 planning period. This includes ARR target allocations from the Annual ARR Allocation and net revenue sources from the Long Term, Annual and Monthly Balance of Planning Period FTR Auctions.[53] In this table, under the balancing congestion

53 The final ARR values may change if load shifts.

and M2M payment rules, any net negative congestion revenue is from day-ahead congestion and does not include balancing congestion. Any remaining surplus will be distributed to ARR holders at the end of the planning period, while any remaining deficiency will be charged to all FTR holders as FTR uplift at the end of the planning period. The actual surplus or deficiency for the planning period is not known until the end of the planning period. In the 2024/2025 planning period and the first ten months of the 2025/2026 planning period, FTRs were paid part of the ARR auction surplus to ensure the payment of the FTR target allocations for months where FTR target allocations were greater than the congestion revenue collected in that month

Table 13-47 Total annual ARR and FTR revenue detail (Dollars (Millions)): 2024/2025 and 2025/2026 planning periods

Accounting Element	2024/2025	2025/2026*
ARR Information		
ARR Target Allocations	$1,448.1	$1,882.7
ARR Credits	$1,448.1	$1,882.7
FTR Auction Revenue	**$1,664.9**	**$2,137.0**
Annual FTR Auction Net Revenue	$1,475.3	$1,895.3
Long Term FTR Auction Net Revenue	$110.0	$153.0
Monthly Balance of Planning Period FTR Auction Net Revenue	$79.6	$88.7
Surplus Auction Revenue		
ARR Surplus (FTR Auction Revenue - ARR Credits)	$216.8	$254.3
ARR Payout Ratio	100%	100%
FTR Targets		
Positive Target Allocations	$2,731.0	$5,474.2
Negative Target Allocations	($573.4)	($1,183.0)
FTR Target Allocations	$3,304.4	$4,291.2
FTR Revenues		
ARR Surplus	$216.8	$254.3
Congestion		
Net Negative Congestion	$0.0	$0.0
Hourly Congestion Revenue	$2,494.9	$4,789.5
Surplus Congestion Revenues Distributed to Other Months	$52.9	$60.2
Total FTR Congestion Credits	$2,691.1	$4,961.4
FTR Payout Ratio		
Congestion	75.5%	111.6%
Congestion and ARR Surplus	98.8%	100.0%
Remaining Deficiency	$39.9	$0.0
Remaining Surplus	$0.0	$670.0

*First ten months of the 2025/2026 planning period

FTR target allocations are defined based on hourly CLMP differences in the day-ahead energy market for FTR paths. FTR credits are paid to FTR holders and, depending on market conditions, can be less than the target allocations but are capped at target allocations. Table 13-48 lists the FTR revenues, target allocations, credits, payout ratios, congestion credit deficiencies and excess congestion charges by month for the 2024/2025 planning period and the first ten months of the 2025/2026 planning period. FTR revenues include congestion and surplus FTR auction revenue.

The total row in Table 13-48 is not the sum of each of the monthly rows because the monthly rows may include excess revenues carried forward from prior months and excess revenues distributed back from later months.

Table 13-48 Monthly FTR accounting summary (Dollars (Millions)): 2024/2025 and 2025/2026 planning periods

Period	FTR Revenues	FTR Target Allocations	FTR Payout Ratio (original)	FTR Credits (with adjustments)	FTR Payout Ratio (with adjustments)	Monthly Credits Surplus (with adjustments)	Monthly Credits Deficiency (with adjustments)
Jun-24	$168.6	$164.0	100.0%	$161.6	98.6%	$4.7	$0.0
Jul-24	$387.4	$347.8	100.0%	$343.2	98.7%	$39.6	$0.0
Aug-24	$272.4	$249.9	100.0%	$246.5	98.6%	$22.5	$0.0
Sep-24	$144.9	$169.2	85.7%	$166.8	98.6%	$0.0	($24.2)
Oct-24	$156.2	$176.3	88.6%	$173.7	98.5%	$0.0	($20.1)
Nov-24	$103.2	$99.3	100.0%	$97.8	98.5%	$3.9	$0.0
Dec-24	$236.6	$260.7	90.7%	$256.9	98.5%	$0.0	($24.1)
Jan-25	$377.6	$334.0	100.0%	$328.8	98.5%	$43.5	$0.0
Feb-25	$155.2	$154.0	100.0%	$151.6	98.4%	$1.2	$0.0
Mar-25	$213.2	$291.2	73.2%	$286.7	98.5%	$0.0	($78.0)
Apr-25	$201.8	$216.7	93.1%	$213.5	98.5%	$0.0	($14.9)
May-25	$274.0	$267.9	100.0%	$264.0	98.5%	$6.0	$0.0
Summary for Planning Period 2024/2025							
Total	$2,691.1	$2,731.0		$2,691.1			($39.9)
Jun-25	$430.0	$346.8	100.0%	$346.8	100.0%	$83.2	$0.0
Jul-25	$625.4	$522.0	100.0%	$522.0	100.0%	$103.4	$0.0
Aug-25	$186.8	$177.0	100.0%	$177.3	100.0%	$9.8	$0.0
Sep-25	$257.3	$263.4	97.7%	$263.6	100.0%	$0.0	($6.1)
Oct-25	$405.5	$378.0	100.0%	$378.0	100.0%	$27.6	$0.0
Nov-25	$239.9	$251.1	95.5%	$251.1	100.0%	$0.0	($11.2)
Dec-25	$457.2	$463.0	98.7%	$463.0	100.0%	$0.0	($5.5)
Jan-26	$1,359.7	$996.0	100.0%	$996.0	100.0%	$363.6	$0.0
Feb-26	$765.7	$623.0	100.0%	$623.0	100.0%	$142.7	$0.0
Mar-26	$233.9	$271.3	86.2%	$271.3	100.0%	$0.0	($37.4)
Summary for Planning Period 2025/2026*							
Total	$4,961.4	$4,291.6		$4,292.1		$670.2	

Figure 13-16 shows the original PJM reported FTR payout ratio by month, excluding excess revenue distribution, for January 2004 through March 2026. The months with payout ratios above 100 percent have congestion revenue greater than the target allocations and the months with payout ratios under 100 percent have congestion revenue that is less than the target allocations. Figure 13-16 also shows the payout ratio after distributing surplus congestion revenue across months within the planning period. The payout ratio for months with a payout ratio less than 100 percent in the current planning period may change if surplus congestion revenue is collected in the remainder of the planning period and assigned to prior months.

Figure 13-16 FTR payout ratio by month, excluding and including excess revenue distribution: January 2004 through March 2026

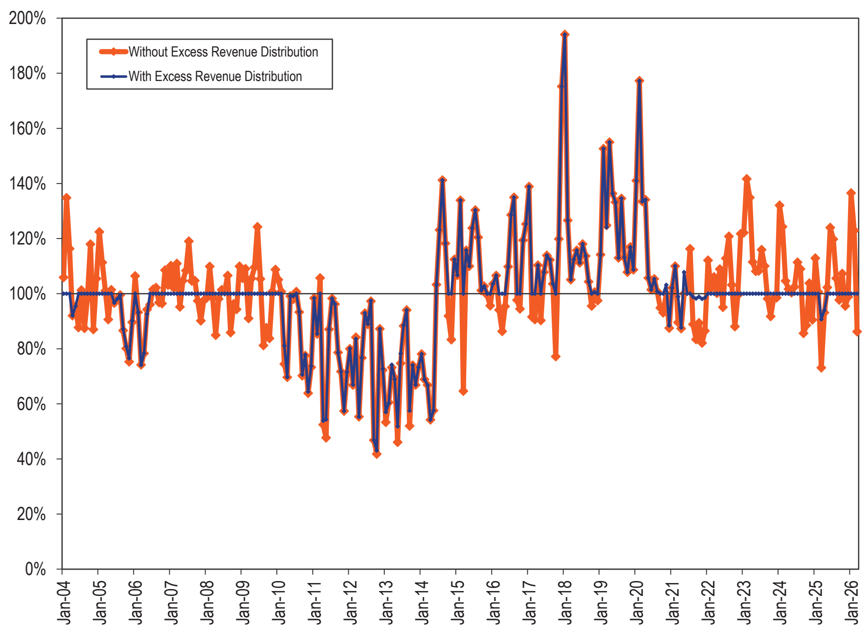


Table 13-49 shows the FTR payout ratio by planning period from the 2003/2004 planning period forward. The 2013/2014 planning period includes the additional revenue from unallocated congestion charges from Balancing Operating Reserves. Beginning with the 2018/2019 planning period payments to FTRs are limited to 100 percent of the target allocations.

The first ten months of the 2025/2026 planning period had a payout ratio of 100.0 percent.

Figure 13-17 shows the day-ahead balancing, total congestion and the FTR surplus from 2005 through March 2026.

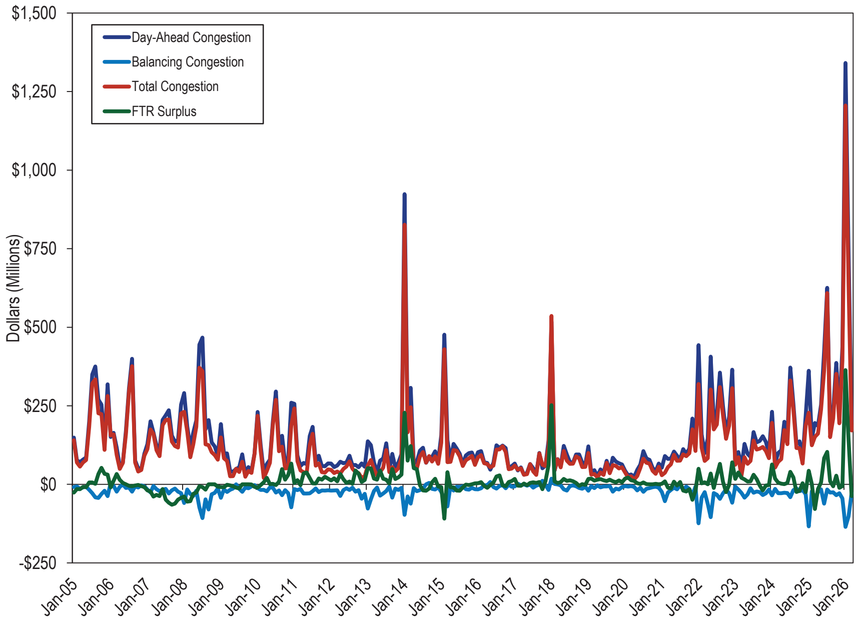
Table 13-49 Reported FTR payout ratio by planning period[54]

Planning Period	FTR Payout Ratio
2003/2004	97.7%
2004/2005	100.0%
2005/2006	90.7%
2006/2007	100.0%
2007/2008	100.0%
2008/2009	100.0%
2009/2010	96.9%
2010/2011	85.0%
2011/2012	80.6%
2012/2013	67.8%
2013/2014	72.8%
2014/2015	116.2%
2015/2016	106.8%
2016/2017	112.6%
2017/2018	138.5%
2018/2019	100.0%
2019/2020	100.0%
2020/2021	98.7%
2021/2022	99.0%
2022/2023	100.0%
2023/2024	100.0%
2024/2025	98.8%
2025/2026*	100.0%

*First ten months of 2025/2026

54 The actual payout ratios for the 2006/2007, 2007/2008, and 2008/2009 planning periods may have exceeded 100 percent.

Figure 13-17 FTR surplus and day-ahead, balancing and total congestion: 2005 through March 2026[55]



Target Allocations and Congestion by Constraint Do Not Match

The path based ARR/FTR market design does not align with congestion based on actual network use. A comparison of the FTR target allocations for individual constraints to the day-ahead and total congestion by constraint provides evidence of this misalignment. Total congestion is the sum of day-ahead and balancing congestion. If FTR target allocations on some paths are significantly greater than actual congestion and FTR target allocations on other paths are significantly less than actual congestion, this is evidence of a serious flaw in the design. It is evidence of a mismatch between the definition of target allocations paid to FTR holders and the congestion that is the purported source of those payments.

FTR target allocations are the result of constraints on day-ahead paths in the energy market. Any specific FTR path may be affected by multiple constraints. Constraints that result in FTR target allocations greater than the congestion that results from those constraints mean that the FTR target allocations are greater than the actual congestion. Figure 13-18 shows the constraints that are the top 10 sources of positive FTR target allocations, for first ten months of the 2025/2026 planning period. Figure 13-18 also shows the corresponding day-ahead congestion and total congestion that result from the identified constraints. Constraints for which FTR target allocations were greater than total congestion resulted in $805.9 million of excess target allocations not funded by actual congestion. Such constraints include constraints in Figure 13-18, such as Lenox – North Meshoppen, which resulted in FTR target allocations that were 1.8 times larger than the corresponding total congestion. In order to pay FTRs their target allocations on these constraints, congestion from other constraints where congestion exceeds target allocations and auction surplus are used as the source. This is not consistent with an efficient market either for other FTR holders or for load.

55 This figure is affected by the identified distribution factor error.

Figure 13-18 Top ten constraint sources of positive FTR target allocations: June 2025 through March 2026[56]

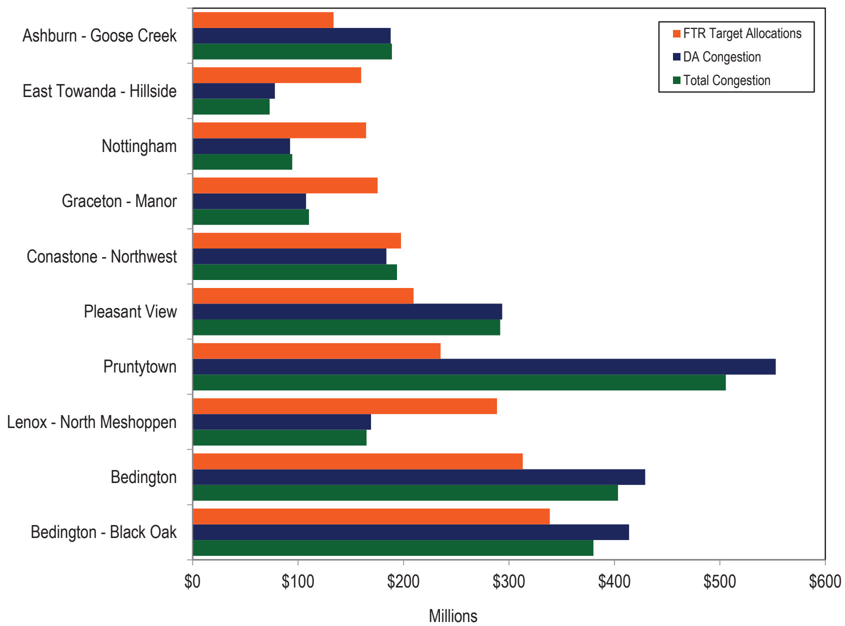


Figure 13-19 shows the hourly FTR target allocations, day-ahead congestion and balancing congestion for the Bedington – Black Oak constraint for the first ten months of the 2025/2026 planning period. Bedington – Black Oak constraint was the largest source of FTR target allocations during this period. The significant and variable difference between constraint specific FTR target allocations and constraint specific day-ahead congestion provides evidence of the misalignment and over allocation of the path based FTR congestion rights relative to the actual network use of the physical energy market.

The Bedington – Black Oak constraint was a significant component of the overallocation of FTRs. FTRs routinely receive more target allocations than the congestion collected from the system because of the misalignment and over allocation of the path based FTR congestion rights relative to the actual network use of the physical energy market. The misalignment and overallocation of path based FTRs is exacerbated when line outages reduce the physical system capability between generation and load (the source of congestion revenue) relative to system capability assumed in the FTR market model.

Figure 13-19 Hourly FTR target allocations, total congestion, day-ahead congestion and balancing congestion for the Bedington – Black Oak constraint: June 2025 through March 2026[57]

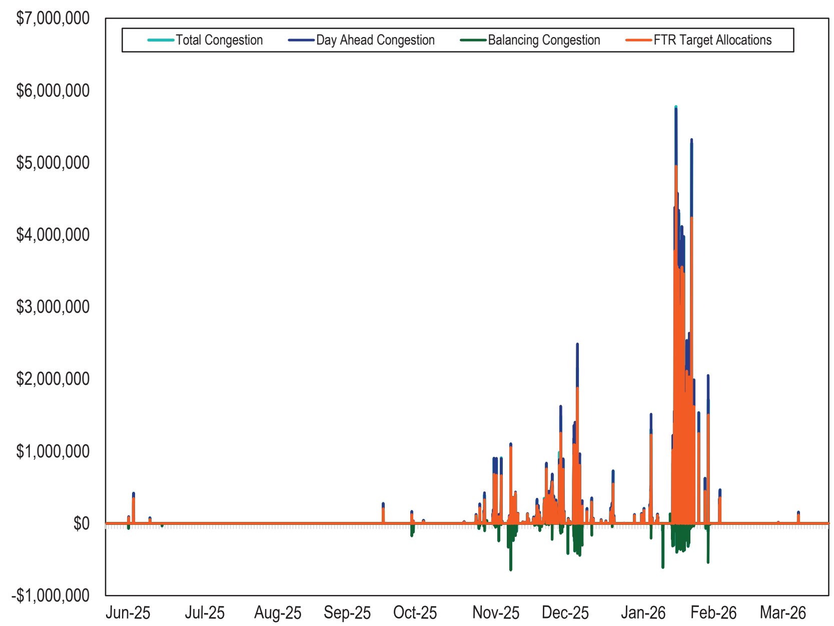


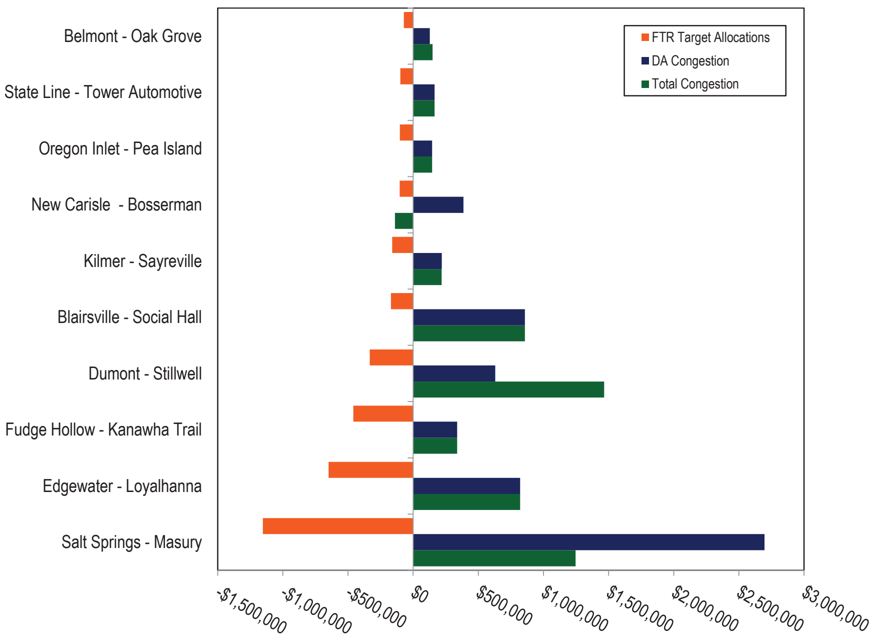
Figure 13-20 shows the constraints that are the top 10 sources of negative FTR target allocations (counter flow) for the first ten months of the 2025/2026 planning period. Figure 13-20 also shows the corresponding day-ahead congestion and total congestion that result from the identified constraints.

56 This figure is affected by the identified distribution factor error.

57 This figure is affected by the identified distribution factor error.

In the first ten months of the 2025/2026 planning period, there were 54 constraints that were sources of negative target allocations. Of the 54 constraints that were sources of negative target allocations, 50 resulted in positive actual total congestion. Constraints that contribute positive congestion revenues and have negative FTR target allocations are a source of funds used in the settlement process to pay for FTR target allocations on FTR paths that are overallocated relative to actual congestion.

Figure 13-20 Top ten constraint sources of negative FTR target allocations: June 2025 through March 2026[58] [59]



ARRs as an Offset to Congestion for Load

Load pays 100 percent of congestion revenues. FTRs, and later ARRs, were intended to return congestion revenues to load to offset an unintended consequence of locational marginal pricing. With the implementation of the current, path based FTR/ARR design, the purpose of FTRs has been subverted. The inconsistencies between actual network solutions used to serve load and path based rights available to load cause a misalignment of congestion paid by load and the congestion paid to load, in aggregate and on a specific load basis. These inconsistencies between actual network use and path based rights cause cross subsidies between ARR holders and FTR holders and among ARR holders. One result of this misalignment is that individual zones have very different offsets due to the location of their path based ARRs compared to their actual congestion costs from actual network use.

Table 13-50 shows the ARR and FTR revenue paid to load, the congestion offset available to load with and without allocating balancing congestion to load and the congestion offset when surplus congestion revenue is allocated to load. The highlighted offsets are the actual offsets based on the rules that were effective in that planning period. The pre 2017/2018 offset is calculated as the ARR credits and the FTR credits excluding balancing congestion and M2M payments, divided by the total day-ahead congestion and the load share of balancing and M2M payments.

Total ARR and self scheduled FTR revenue offset only 55.3 percent of total congestion costs for the first ten months of the 2025/2026 planning period.

58 New Carisle – Bosserman is the spelling provided in PJM data, rather than New Carlisle – Bosserman.
59 This figure is affected by the identified distribution factor error.

Table 13-50 ARR and self scheduled FTR total congestion offset (in millions) for ARR holders: 2011/2012 through 2025/2026 planning periods[60]

	Revenue								Pre 2017/2018 (Without Balancing)		2017/2018 (With Balancing)		Post 2017/2018 (With Balancing and Surplus)		Effective Offset	
Planning Period	ARR Credits	Unadjusted SS FTR Credits	Day Ahead Congestion	Balancing + M2M Congestion	Total Congestion	Surplus Revenue Pre 2017/2018 Rules	Surplus Revenue 2017/2018 Rules	Post 2017/2018 Rules	Total ARR/ FTR Offset	Percent Offset	Current Revenue Received	Percent Offset	New Revenue Received	New Offset	Cumulative Revenue	Offset
2011/2012	$515.6	$310.0	$1,025.4	($275.7)	$749.7	($50.6)	$35.6	$113.9	$775.0	103.4%	$585.5	78.1%	$663.8	88.5%	$775.0	103.4%
2012/2013	$356.4	$268.4	$904.7	($379.9)	$524.8	($94.0)	$18.4	$62.1	$530.7	101.1%	$263.2	50.2%	$306.9	58.5%	$530.7	101.1%
2013/2014	$339.4	$626.6	$2,231.3	($360.6)	$1,870.6	($139.4)	($49.0)	($49.0)	$826.5	44.2%	$556.3	29.7%	$556.3	29.7%	$826.5	44.2%
2014/2015	$487.4	$348.1	$1,625.9	($268.3)	$1,357.6	$36.7	$111.2	$400.6	$872.2	64.2%	$678.4	50.0%	$967.8	71.3%	$872.2	64.2%
2015/2016	$641.8	$209.2	$1,098.7	($147.6)	$951.1	$9.2	$42.1	$188.9	$860.2	90.4%	$745.5	78.4%	$892.3	93.8%	$860.2	90.4%
2016/2017	$648.1	$149.9	$885.7	($104.8)	$780.8	$15.1	$36.5	$179.0	$813.1	104.1%	$729.6	93.4%	$872.1	111.7%	$813.1	104.1%
2017/2018	$429.6	$212.3	$1,322.1	($129.5)	$1,192.6	$52.3	$80.4	$370.7	$694.2	58.2%	$592.8	49.7%	$883.1	74.1%	$592.8	49.7%
2018/2019	$531.6	$130.1	$832.7	($152.6)	$680.0	($5.8)	$16.2	$112.2	$655.87	96.4%	$525.3	77.2%	$621.3	91.4%	$621.3	91.4%
2019/2020	$547.6	$91.9	$612.1	($169.4)	$442.7	($1.6)	$21.6	$157.8	$637.9	144.1%	$491.7	111.1%	$627.9	141.8%	$627.9	141.8%
2020/2021	$392.7	$179.9	$899.6	($256.2)	$643.4	($43.2)	($0.0)	($0.0)	$529.31	82.3%	$316.4	49.2%	$316.4	49.2%	$316.4	49.2%
2021/2022	$469.7	$500.5	$2,069.2	($457.4)	$1,611.8	($104.6)	($2.9)	($2.9)	$865.6	53.7%	$509.9	31.6%	$509.9	31.6%	$509.9	31.6%
2022/2023	$998.7	$630.0	$2,223.5	($526.5)	$1,697.1	($80.6)	$65.1	$235.2	$1,548.2	91.2%	$1,167.4	68.8%	$1,337.5	78.8%	$1,337.5	78.8%
2023/2024	$912.1	$371.4	$1,618.9	($327.0)	$1,291.9	($44.1)	$24.6	$117.2	$1,239.4	95.9%	$981.2	76.0%	$1,073.7	83.1%	$1,073.7	83.1%
2024/2025	$954.7	$658.0	$2,494.8	($475.5)	$2,019.4	($124.2)	($9.6)	($9.6)	$1,488.6	73.7%	$1,127.7	55.8%	$1,127.7	55.8%	$1,127.7	55.8%
2025/2026*	$988.8	$1,262.3	$4,788.4	($613.1)	$4,175.3	$16.4	$196.8	$669.0	$2,267.5	54.3%	$1,834.8	43.9%	$2,307.0	55.3%	$2,307.0	55.3%
Total	$9,214.1	$5,909.1	$24,473.7	($4,619.0)	$19,854.7	($597.1)	$535.4	$2,385.9	$14,526.0	73.2%	$11,039.5	55.6%	$12,890.0	64.9%	$13,192.0	66.0%

*First ten months of the 2025/2026 planning period

Table 13-50 illustrates the inadequacies of the ARR/FTR design. The goal of the design should be to give the rights to 100 percent of the congestion revenues to the load.

Table 13-51 shows the cumulative offset and shortfall using the rules that were effective in the given planning period to calculate the ARR/FTR revenue. The cumulative offset, beginning in the 2011/2012 planning period, is the sum of the revenue received for that planning period and all previous planning periods divided by the total congestion for that planning period and all previous planning periods. The cumulative shortfall is the cumulative difference between the ARR holders' revenue and the congestion they paid, for each planning period and the planning periods prior to each planning period.

From the 2011/2012 planning period through the first ten months of the 2025/2026 planning period, the cumulative offset, the cumulative return of congestion to load, was only 66.0 percent based on the total congestion and the effective offset rules that were in place for each planning period. Load has been underpaid by $6.8 billion from the 2011/2012 planning period through the first ten months of the 2025/2026 planning period. This is an increase of $1.9 billion from the $4.9 billion that load had been underpaid for the 2011/2012 planning period through the 2024/2025 planning period. The $6.8 billion is the difference between the total congestion column ($19.8 billion) and the total offset column ($13.2 billion) in Table 13-50.

60 This table is affected by the identified distribution factor error.

Table 13-51 ARR and self scheduled FTR cumulative offset for ARR holders: 2011/2012 through 2025/2026 planning periods[61]

Planning Period	Cumulative Offset	Cumulative Shortfall (Millions)
2011/2012	103.4%	$25.3
2012/2013	102.4%	$31.2
2013/2014	67.8%	($1,012.9)
2014/2015	66.7%	($1,498.3)
2015/2016	70.9%	($1,589.2)
2016/2017	75.0%	($1,556.9)
2017/2018	71.0%	($2,156.7)
2018/2019	72.7%	($2,215.4)
2019/2020	76.3%	($2,030.2)
2020/2021	74.4%	($2,357.2)
2021/2022	68.0%	($3,459.1)
2022/2023	69.5%	($3,818.7)
2023/2024	70.7%	($4,036.8)
2024/2025	68.8%	($4,928.5)
2025/2026*	66.0%	($6,796.8)

*First ten months of the 2025/2026 planning period

Zonal ARR Congestion Offset

Zonal ARR congestion offsets vary significantly across zones. There is no good reason that this should be the result of a system designed to return congestion to load. PJM has offered no explanation for this result. This outcome is a direct result of the flawed definition of congestion and of the method for assigning rights to congestion to ARR holders. The results show that path based ARR assignments in the current path based ARR/FTR design are not aligned with actual network use by load, and are therefore not aligned with how congestion is actually paid by load on actual network usage. Due to this misalignment of ARR rights relative to actual network usage, individual loads cannot claim the congestion they paid through assigned ARRs. One result of the misalignment of path based ARR rights are cross subsidies among ARR holders.

61 This table is affected by the identified distribution factor error.

ARRs are allocated to zonal load based on historical generation to load transmission contract paths, in many cases based on 1999 contract paths. ARRs are allocated within zones based on zonal base load (Stage 1A) and zonal peak loads (other stages). ARR revenue is the result of the prices that result from the sale of FTRs through the FTR auctions. ARR revenue for each zone is the revenue for the ARRs that sink in each zone.

Congestion paid by load in a zone is the total difference between what the zonal load pays in congestion charges net of payments to the generation that serves the zonal load, including generation in the zone and outside the zone.[62]

Table 13-52 shows the day-ahead congestion and balancing congestion and M2M charges paid by load in each zone along with the congestion offsets paid to load: FTR auction revenue; self scheduled FTR revenue adjusted by the payout ratio for FTRs if below 100 percent; and the allocation of end of planning period surplus.[63] The offset for the first ten months of the 2025/2026 planning period assigns the current surplus revenue at the end of the quarter to ARR holders. Table 13-52 also shows payments by load for balancing congestion and M2M payments. The total congestion offset paid to load is the sum of all of those credits and charges.

The zonal offset percentage shown in Table 13-52 is the sum of the congestion related revenues (offset) paid to load in each zone divided by the total congestion payment made by load in each zone.

62 *See* "Constraint Based Congestion Calculations," PJM ARR FTR Market Task Force (July 17, 2020) <https://www.pjm.com/-/media/committees-groups/task-forces/afmtf/2020/20200722/20200722-item-03a-constraint-based-congestion-calculations.ashx>.
63 See *2020 Annual State of the Market Report for PJM*, Volume 2, Section 11: Congestion and Marginal Losses

Table 13-52 Zonal ARR and self scheduled FTR total congestion offset (in millions) for ARR holders: 2025/2026 planning period[64]

Zone	ARR Credits	Adjusted FTR Credits	Balancing+ M2M Charge	Surplus Allocation	Total Offset	Day Ahead Congestion	Balancing Congestion	M2M Payments	Total Congestion	Offset
ACEC	$2.0	$0.1	($6.77)	$0.9	($3.7)	$51.7	($5.4)	($1.3)	$45.0	(8.3%)
AEP	$74.2	$244.3	($95.0)	$78.1	$301.6	$747.4	($75.9)	($19.0)	$652.4	46.2%
APS	$71.7	$219.2	($42.4)	$45.5	$294.1	$332.2	($35.7)	($6.7)	$289.8	101.5%
ATSI	$50.4	$4.0	($42.1)	$21.7	$34.0	$331.0	($33.2)	($9.0)	$288.9	11.8%
BGE	$177.0	$20.4	($23.5)	$77.9	$251.9	$215.4	($19.4)	($4.1)	$191.9	131.3%
COMED	$90.4	$3.9	($56.3)	$38.5	$76.5	$484.8	($43.6)	($12.6)	$428.5	17.9%
DAY	$11.6	$3.5	($11.3)	$5.3	$9.1	$88.8	($9.0)	($2.4)	$77.5	11.7%
DOM	$125.8	$688.4	($109.0)	$14.9	$720.1	$867.3	($91.0)	($18.1)	$758.3	95.0%
DPL	$88.3	$17.2	($16.8)	$4.3	$93.0	$130.0	($14.2)	($2.6)	$113.2	82.1%
DUKE	$34.0	$2.2	($17.4)	$225.3	$244.1	$137.0	($13.9)	($3.6)	$119.6	204.1%
DUQ	$10.0	$0.6	($8.2)	$41.8	$44.2	$60.2	($6.5)	($1.7)	$51.9	85.1%
EKPC	$6.3	$0.1	($10.6)	$2.6	($1.6)	$85.0	($8.7)	($2.0)	$74.4	(2.2%)
EXT	$0.9	$0.0	($14.3)	$0.4	($13.0)	$69.7	($14.3)	$0.0	$55.4	(23.4%)
JCPLC	$5.3	$6.4	($18.3)	$3.2	($3.5)	$141.5	($15.3)	($3.0)	$123.2	(2.8%)
MEC	$13.5	$2.8	($17.4)	$6.2	$5.1	$92.2	($15.4)	($2.0)	$74.8	6.8%
OVEC	$0.0	$0.0	($0.6)	$0.0	($0.6)	$5.9	($0.6)	($0.0)	$5.3	(11.8%)
PE	$43.4	$19.6	($11.1)	$22.3	$74.2	$87.9	($8.9)	($2.2)	$76.8	96.6%
PECO	$10.3	$0.3	($28.1)	$4.5	($13.1)	$202.4	($22.9)	($5.2)	$174.3	(7.5%)
PEPCO	$74.9	$18.9	($22.0)	$34.5	$106.2	$203.3	($18.2)	($3.8)	$181.3	58.6%
PPL	$52.4	$7.9	($31.0)	$22.8	$52.1	$226.9	($25.4)	($5.5)	$195.9	26.6%
PSEG	$44.0	$2.5	($29.8)	$18.7	$35.4	$220.3	($24.0)	($5.8)	$190.5	18.6%
REC	$2.1	$0.0	($1.0)	$0.9	$2.0	$7.4	($0.8)	($0.2)	$6.4	31.0%
Total	$988.8	$1,262.1	($613.1)	$670.2	$2,308.0	$4,788.4	($502.3)	($110.8)	$4,175.3	55.3%

The total congestion offset paid to loads in the first ten months of the 2025/2026 planning period was 52.8 percent of congestion costs. The results vary significantly by zone. Loads in some zones, like BGE and DOM, receive substantially more in offsets than their total congestion payments. Loads in other zones, like EKPC, receive substantially less in offsets than their total congestion payments. Loads in some zones, like ACEC, have higher balancing congestion and M2M charges than the load is able to offset with ARRs and FTRs, resulting in a negative total offset. The offsets are a function of the assignment of ARRs and the valuation of ARRs in the FTR auctions.

The amount and proportion of the offset that can be realized by load serving entities via their ARR allocations varies by planning period. The offsets are a function of the assignment of ARRs relative actual network sources of congestion paid, the valuation of ARRs in the FTR auctions and the congestion revenue from self scheduled ARRs. If the prices for FTRs are high relative to realized congestion, the offset provided by ARR is increased relative to cases where the prices for FTRs are low relative to realized congestion. While the amount of congestion that is returned to the load varies by planning period, PJM's ARR/FTR design has consistently failed to return the congestion revenues to the load that paid it. It is not possible for load to recover all of the congestion that they pay under the current design in which the rights to congestion revenues are assigned based on fictitious contract paths.

64 This table is affected by the identified distribution factor error.

Offset If All ARRs Are Held As ARRs

Table 13-53 shows the total congestion offset that would be available to ARR holders via allocated ARRs, by zone, if the ARRs holders held all their allocated ARRs in the 2023/2024, 2024/2025, and the first ten months of the 2025/2026 planning periods and did not self schedule any. If ARR holders held all their allocated ARRs for the first ten months of the 2025/2026 planning period, the ARR Target Allocations would have offset 23.8 percent of the congestion paid by load. However, the offset that would be received by individual zones varies widely, from -10.5 percent for ACEC to 85.0 percent for APS.

Table 13-53 Offset available to load if all ARRs are held: 2023/2024 through 2025/2026 planning periods[65]

	23/24 Planning Period				24/25 Planning Period				25/26 Planning Period*			
	ARR Held TA	Bal+M2M Charges	Congestion+M2M	Offset	ARR Held TA	Bal+M2M Charges	Congestion+M2M	Offset	ARR Held TA	Bal+M2M Charges	Congestion+M2M	Offset
ACEC	$4.9	($3.8)	$10.8	9.7%	$4.5	($5.4)	$18.8	(5.1%)	$2.1	($6.8)	$45.0	(10.5%)
AEP	$185.2	($50.4)	$201.8	66.8%	$160.6	($72.1)	$327.3	27.1%	$187.0	($95.0)	$652.4	14.1%
APS	$85.5	($22.4)	$87.6	72.1%	$96.9	($33.3)	$149.2	42.6%	$109.1	($42.4)	$289.8	23.0%
ATSI	$50.3	($25.6)	$99.4	24.8%	$61.9	($33.8)	$169.2	16.6%	$52.0	($42.1)	$288.9	3.4%
BGE	$145.8	($12.5)	$44.4	300.4%	$153.0	($18.2)	$79.9	168.7%	$186.5	($23.5)	$191.9	85.0%
COMED	$44.9	($31.4)	$215.9	6.3%	$55.3	($42.4)	$232.2	5.5%	$92.2	($56.3)	$428.5	8.4%
DAY	$13.3	($6.7)	$23.7	27.7%	$13.7	($8.8)	$39.1	12.5%	$12.7	($11.3)	$77.5	1.8%
DOM	$642.0	($52.0)	$181.8	324.6%	$430.5	($82.9)	$323.2	107.6%	$539.5	($109.0)	$758.3	56.8%
DPL	$69.6	($8.4)	$51.2	119.7%	$90.8	($13.9)	$70.7	108.8%	$100.1	($16.8)	$113.2	73.5%
DUKE	$52.1	($10.3)	$37.7	110.9%	$49.2	($13.3)	$55.2	64.9%	$35.6	($17.4)	$119.6	15.2%
DUQ	$8.6	($5.2)	$15.1	22.5%	$12.1	($6.8)	$25.1	21.0%	$10.4	($8.2)	$51.9	4.2%
EKPC	$6.5	($5.7)	$20.6	4.0%	$8.3	($8.1)	$32.2	0.7%	$6.3	($10.6)	$74.4	(5.8%)
EXT	$1.9	($9.6)	$26.4	(29.1%)	$1.2	($12.7)	$27.2	(42.1%)	$1.3	($14.3)	$55.4	(23.4%)
JCPLC	$4.6	($10.4)	$32.4	(18.1%)	$9.1	($14.6)	$54.8	(10.0%)	$7.7	($18.3)	$123.2	(8.6%)
MEC	$34.2	($6.7)	$21.8	126.3%	$24.2	($12.7)	$35.5	32.4%	$14.9	($17.4)	$74.8	(3.3%)
OVEC	($0.0)	($0.4)	$2.1	(19.1%)	$0.0	($0.5)	$3.6	(13.6%)	$0.0	($0.6)	$5.3	(11.9%)
PE	$22.2	($6.5)	$28.3	55.6%	$50.0	($9.6)	$43.7	92.5%	$53.4	($11.1)	$76.8	55.0%
PECO	$21.2	($14.9)	$42.3	14.8%	$29.8	($22.0)	$75.6	10.3%	$10.7	($28.1)	$174.3	(10.0%)
PEPCO	$65.4	($11.6)	$38.3	140.7%	$65.3	($17.0)	$69.3	69.8%	$82.6	($22.0)	$181.3	33.4%
PPL	$80.0	($15.6)	$57.9	111.2%	$68.1	($23.2)	$97.0	46.3%	$54.5	($31.0)	$195.9	12.0%
PSEG	$69.3	($16.4)	$50.3	105.0%	$81.1	($23.5)	$87.2	66.1%	$44.8	($29.8)	$190.5	7.9%
REC	$2.7	($0.6)	$2.2	98.8%	$3.1	($0.8)	$3.5	66.0%	$2.1	($1.0)	$6.4	17.4%
Total	$1,610.1	($327.0)	$1,291.9	99.3%	$1,468.7	($475.4)	$2,019.4	49.2%	$1,605.5	($613.1)	$4,175.3	23.8%

* First ten months of the 2025/2026 planning period

Offset If All ARRs Are Self Scheduled

Table 13-54 shows the total congestion offset that would be available to ARR holders via allocated ARRs, by zone, if the ARR holders self scheduled all their ARRs received in the annual auction process as FTRs in the 2023/2024, 2024/2025, and the first ten months of the 2025/2026 planning periods. Market rules allow ARRs available in the annual auction process to be self scheduled as FTRs. Any ARRs awarded monthly as residual ARRs cannot be self scheduled but provide ARR revenue based on monthly auction results. The calculated self scheduled FTR target allocations assume a 100 percent payout ratio. Residual ARRs

65 This table is affected by the identified distribution factor error.

cannot be self scheduled and are included in addition to the self scheduled FTR target allocations. If ARR holders had self scheduled all their allocated ARRs to FTRs for the first ten months of the 2025/2026 planning period, the ARR Target Allocations would have offset 67.9 percent of the congestion paid by load. The results show that the recovery of congestion varies significantly by zone and that the load in some zones recovers more than the congestion paid and the load in other zones recovers less. This result is not consistent with a rational FTR/ARR design under which all load would be returned their congestion, but no more and no less.

Table 13-54 Offset available to load if all ARRs self scheduled: 2023/2024 through 2025/2026 planning periods[66]

	23/24 Planning Period					24/25 Planning Period					25/26* Planning Period				
	SS FTR	Residual ARR Credits	Bal+M2M Charges	Congestion+M2M	Offset	SS FTR	Residual ARR Credits	Bal+M2M Charges	Congestion+M2M	Offset	SS FTR	Residual ARR Credits	Bal+M2M Charges	Congestion+M2M	Offset
ACEC	$4.5	$0.0	($3.8)	$10.8	6.6%	$0.7	$0.0	($5.4)	$18.8	(25.3%)	$3.0	$0.0	($6.8)	$45.0	(8.3%)
AEP	$101.4	$3.2	($50.4)	$201.8	26.8%	$215.2	$4.7	($72.1)	$327.3	45.2%	$331.0	$0.5	($95.0)	$652.4	36.3%
APS	$77.5	$0.6	($22.4)	$87.6	63.5%	$133.7	$8.3	($33.3)	$149.2	72.9%	$637.7	$0.2	($42.4)	$289.8	205.5%
ATSI	$84.3	$0.1	($25.6)	$99.4	59.1%	$74.8	$0.1	($33.8)	$169.2	24.3%	$81.9	$0.0	($42.1)	$288.9	13.8%
BGE	$190.3	$0.0	($12.5)	$44.4	400.6%	$186.1	$0.2	($18.2)	$79.9	210.4%	$317.5	$1.7	($23.5)	$191.9	154.1%
COMED	$83.0	$0.0	($31.4)	$215.9	23.9%	$76.6	$0.1	($42.4)	$232.2	14.8%	$227.5	$0.0	($56.3)	$428.5	40.0%
DAY	$12.3	$0.2	($6.7)	$23.7	24.4%	$15.3	$0.9	($8.8)	$39.1	18.9%	$15.0	$0.0	($11.3)	$77.5	4.7%
DOM	$292.8	$0.5	($52.0)	$181.8	132.8%	$32.4	$8.5	($82.9)	$323.2	(13.0%)	$956.7	$60.9	($109.0)	$758.3	119.8%
DPL	$87.8	$0.0	($8.4)	$51.2	155.3%	$627.0	$0.5	($13.9)	$70.7	868.1%	$43.1	$10.1	($16.8)	$113.2	32.1%
DUKE	$55.8	$0.0	($10.3)	$37.7	120.8%	$88.7	$0.2	($13.3)	$55.2	136.8%	$7.0	$0.1	($17.4)	$119.6	(8.6%)
DUQ	$19.7	$0.0	($5.2)	$15.1	96.3%	$12.7	$0.0	($6.8)	$25.1	23.4%	$119.3	$0.0	($8.2)	$51.9	214.0%
EKPC	$8.7	$0.0	($5.7)	$20.6	14.4%	$4.8	$1.1	($8.1)	$32.2	(7.0%)	$6.9	$0.0	($10.6)	$74.4	(4.9%)
EXT	$1.3	$0.0	($9.6)	$26.4	(31.4%)	$1.2	$0.0	($12.7)	$27.2	(42.0%)	$2.4	$0.0	($14.3)	$55.4	(21.5%)
JCPLC	$6.1	$0.0	($10.4)	$32.4	(13.3%)	$9.1	$0.1	($14.6)	$54.8	(9.6%)	$14.2	$0.5	($18.3)	$123.2	(2.9%)
MEC	$5.4	$0.0	($6.7)	$21.8	(6.3%)	$18.6	$0.3	($12.7)	$35.5	17.6%	$19.4	$0.7	($17.4)	$74.8	3.6%
OVEC	($0.0)	$0.0	($0.4)	$2.1	(18.0%)	($0.0)	$0.0	($0.5)	$3.6	(13.6%)	$0.0	$0.0	($0.6)	$5.3	(11.9%)
PE	$46.0	$0.0	($6.5)	$28.3	139.5%	$6.4	$0.2	($9.6)	$43.7	(6.9%)	$130.6	$0.0	($11.1)	$76.8	155.5%
PECO	$29.0	$0.0	($14.9)	$42.3	33.4%	$119.8	$0.0	($22.0)	$75.6	129.5%	$4.3	$0.0	($28.1)	$174.3	(13.7%)
PEPCO	$73.3	$0.0	($11.6)	$38.3	161.4%	$90.1	$0.3	($17.0)	$69.3	105.9%	$186.2	$0.1	($22.0)	$181.3	90.6%
PPL	$37.1	$0.0	($15.6)	$57.9	37.1%	$107.3	$0.6	($23.2)	$97.0	87.4%	$182.8	$0.0	($31.0)	$195.9	77.5%
PSEG	$49.3	$0.0	($16.4)	$50.3	65.3%	$66.8	$0.1	($23.5)	$87.2	49.8%	$82.9	$0.8	($29.8)	$190.5	28.3%
REC	$3.7	$0.0	($0.6)	$2.2	143.6%	$4.4	$0.0	($0.8)	$3.5	104.2%	$3.7	$0.2	($1.0)	$6.4	44.8%
Total	$1,269.4	$4.5	($327.0)	$1,291.9	73.3%	$1,891.6	$26.3	($475.4)	$2,019.4	71.4%	$3,373.2	$76.0	($613.1)	$4,175.3	67.9%

* First ten months of the 2025/2026 planning period

ARR Allocation and Congestion In and Out of Zone

Table 13-55 shows the share of ARR MW for the 2023/2024, 2024/2025, and 2025/2026 planning periods with paths that source inside and outside the zone where the ARR load is located (see Table 13-4) and the proportion of congestion that results from constraints that are inside and outside the zone for the 2023/2024, 2024/2025 and the first ten months of the 2025/2026 planning periods. Table 13-55 allows a comparison of externally sourced ARRs with the

66 This table is affected by the identified distribution factor error.

congestion that results from external constraints. For example, 98.0 percent of ACEC congestion in the first ten months of the 2025/2026 planning period results from constraints that are outside of the zone, but only 55.9 percent of ACEC ARRs originate outside the zone for the 2025/2026 planning period ARR allocations.

Table 13-55 illustrates one of the fundamental issues with the contract path based approach to ARR/FTR design. In the PJM market, which operates as an integrated network, a significant proportion of congestion results from constraints that are not in the same zone as load, but the assignment of ARRs is inconsistent with that fact. This inconsistency makes it impossible for load to match ARRs with the actual sources of congestion.

Table 13-55 ARR Allocation and Congestion from inside and outside zone: 2023/2024, 2024/2025 and 2025/2026 planning periods[67]

	2023/2024 ARRs		2023/2024 Congestion		2024/2025 ARRs		2024/2025 Congestion		2025/2026 ARRs		2025/2026* Congestion	
	Out of Zone	In Zone	Out of Zone	In Zone	Out of Zone	In Zone	Out of Zone	In Zone	Out of Zone	In Zone	Out of Zone	In Zone
ACEC	49.1%	50.9%	97.2%	2.8%	55.1%	44.9%	98.1%	1.9%	44.1%	55.9%	98.0%	2.0%
AEP	10.1%	89.9%	89.1%	10.9%	9.4%	90.6%	86.2%	13.8%	13.9%	86.1%	95.3%	4.7%
APS	17.3%	82.7%	96.2%	3.8%	15.9%	84.1%	91.9%	8.1%	11.5%	88.5%	67.5%	32.2%
ATSI	33.2%	66.8%	95.8%	4.2%	35.1%	64.9%	96.7%	3.3%	41.5%	58.5%	98.3%	1.7%
BGE	38.0%	62.0%	86.5%	13.5%	39.9%	60.1%	87.7%	12.3%	49.4%	50.6%	93.0%	7.0%
COMED	0.0%	100.0%	58.6%	41.4%	0.1%	99.9%	77.6%	22.4%	0.0%	100.0%	87.0%	13.0%
DAY	87.2%	12.8%	100.0%	0.0%	92.6%	7.4%	100.0%	0.0%	79.9%	20.1%	100.0%	0.0%
DOM	0.4%	99.6%	87.8%	12.2%	2.0%	98.0%	65.7%	34.3%	0.5%	99.5%	69.9%	30.1%
DPL	23.2%	76.8%	61.9%	38.1%	26.0%	74.0%	46.2%	53.8%	28.7%	71.3%	78.1%	21.9%
DUKE	45.0%	55.0%	94.6%	5.4%	49.1%	50.9%	97.2%	2.8%	49.8%	50.2%	97.3%	2.7%
DUQ	96.2%	3.8%	99.8%	0.2%	97.0%	3.0%	97.4%	2.6%	91.2%	8.8%	99.8%	0.2%
EKPC	100.0%	0.0%	99.8%	0.2%	100.0%	0.0%	99.2%	0.8%	99.6%	0.4%	99.4%	0.6%
EXT	100.0%	0.0%	94.4%	5.6%	100.0%	0.0%	95.3%	4.7%	100.0%	0.0%	93.7%	6.3%
JCPL	34.6%	65.4%	97.9%	2.1%	58.9%	41.1%	96.5%	3.5%	72.2%	27.8%	100.0%	0.0%
OVEC	38.8%	61.2%	80.0%	20.0%	38.7%	61.3%	55.9%	44.1%	30.2%	69.8%	98.4%	1.6%
MEC	100.0%	0.0%	91.1%	8.9%	66.7%	0.0%	93.4%	6.6%	100.0%	0.0%	94.0%	6.0%
PE	16.2%	83.8%	86.2%	13.8%	24.6%	75.4%	76.0%	24.0%	26.5%	73.5%	89.4%	10.6%
PECO	21.6%	78.4%	90.2%	9.8%	6.9%	93.1%	90.6%	9.4%	2.3%	97.7%	97.9%	2.1%
PEPCO	47.2%	52.8%	99.8%	0.2%	46.9%	53.1%	99.5%	0.5%	24.1%	75.9%	99.5%	0.5%
PPL	2.6%	97.4%	92.0%	8.0%	5.8%	94.2%	89.7%	10.3%	1.0%	99.0%	91.9%	8.1%
PSEG	47.8%	52.2%	99.2%	0.8%	54.6%	45.4%	99.3%	0.7%	53.5%	46.5%	98.9%	1.1%
REC	100.0%	0.0%	83.4%	16.6%	100.0%	0.0%	79.6%	20.4%	100.0%	0.0%	99.4%	0.6%
Total	22.1%	77.9%	85.6%	14.4%	22.4%	77.6%	84.5%	15.5%	21.4%	78.6%	88.2%	11.8%

*first ten months of the 2025/2026 planning period for congestion

67 This table is affected by the identified distribution factor error.

Credit

There were four payment defaults and two collateral defaults in the first three months of 2026. Each of the payment defaults was promptly cured.

On December 21, 2021, PJM submitted a change to the credit rules to FERC.[68] PJM proposed to replace the current credit calculation, which is largely based on a weighted average historical FTR value, with an initial margin based on a risk confidence interval from an Historical Simulation Initial Margining (HSIM) analysis model. PJM's proposal included the use of a 97 percent confidence interval, meaning a 97 percent probability that the initial margin collected would cover potential default costs.

On February 28, 2022, FERC rejected PJM's filing recommending a 97 percent confidence interval because the record did not support 97 percent.[69] FERC instituted a Section 206 proceeding, but recognized that PJM could propose revisions through a Section 205 filing. On June 3, 2022, PJM submitted the same change to the credit rules as the December 21, 2021, filing to FERC.[70] The June 3, 2022, filing included a cost benefit analysis for the proposed use of a 97 percent confidence interval compared to the use of a 99 percent confidence interval. The MMU objected to PJM's filing and proposed a 99 percent confidence interval, with a transition to a 100 percent confidence interval.[71] On September 21, 2023, FERC directed PJM to use a 99 percent confidence level in the HSIM model.[72]

The most fundamental point is that if costs are shifted from FTR buyers to other market participants, no logical cost-benefit analysis can show that the other market participants benefit in any way. Under the current default rules, the cost of default is socialized to all market participants, not just those participating in the FTR market. The 99 percent confidence interval places more of the risk where it belongs, on the FTR market participants that are engaged in the risky behavior, than the 97 percent confidence interval. The goal of internalizing as much of the risk to the FTR participants as possible, where it belongs, could be more directly addressed either by using 100 percent or by directly assigning the risk to those in the FTR market rather than all market participants.

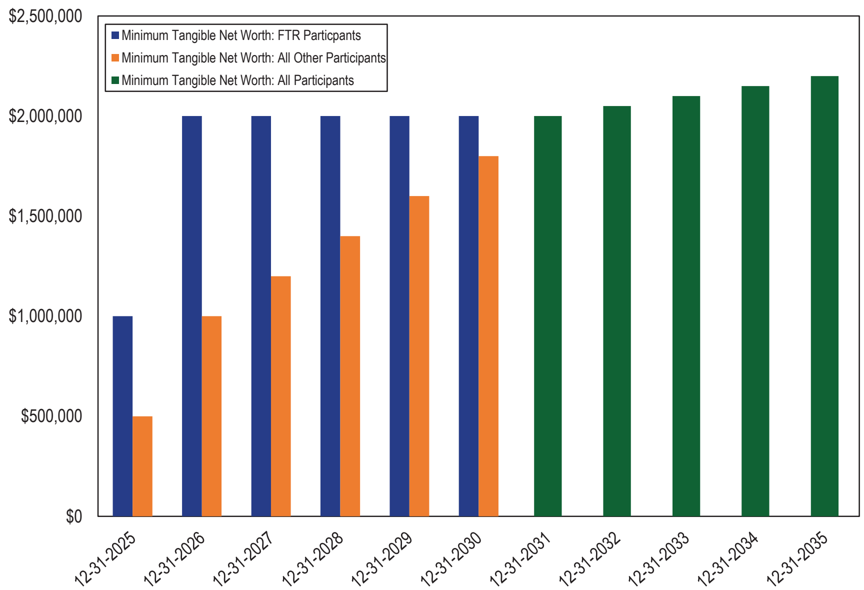
The PJM minimum credit requirements (minimum tangible net worth and minimum tangible assets) were set as fixed dollar amounts in 2011 in FERC Order No. 741 based on whether the market participant held FTRs. PJM completed a review of the minimum credit requirements in the Risk Management Committee in 2025. The MMU and PJM developed a joint package to increase the fixed minimum credit requirements to be consistent with updated risks. The proposal was approved by the Risk Management Committee on October 22, 2025. The proposal was approved by the Markets and Reliability Committee on December 17, 2025. The proposal was approved by the Members Committee on January 22, 2026. The new minimum credit requirements will be implemented on the first December 31 after PJM receives FERC approval for the revised tariff.

Under the revised tariff, minimum tangible net worth requirements will increase from $1,000,000 to $2,000,000 for FTR participants and from $500,000 to $1,000,000 for all other market participants. For five years, there will be a $200,000 annual increase in the minimum tangible net worth requirements for all other market participants. Beginning in the sixth year, there will be an annual 3 percent increase to the minimum credit requirements for all participants, rounded to the nearest $50,000. Participants will continue to be able to satisfy the minimum credit requirements with minimum tangible assets exceeding $10,000,000 for FTR participants or $5,000,000 for all other participants. Under the revised tariff, any participant who satisfies the minimum credit requirements through tangible assets must also have a positive tangible net worth.

Figure 13-21 shows the maximum tangible net worth requirements for FTR participants and all other participants for 2025 through 2035 under the revised tariff language, if the revised tariff language is approved by FERC in 2026. After 2035, minimum tangible will continue to increase 3 percent each year, rounded to the nearest $50,000.

68 *See* "Revisions to PJM's FTR Credit Requirement and Request for 28-Day Comment Period," Docket No. ER22-000 (December 21, 2021).
69 See 178 FERC ¶ 61,146.
70 See "Revisions to PJM's FTR Credit Requirement," Docket No. ER22-2029-000 (June 3, 2022).
71 See Comments of the Independent Market Monitor for PJM, Docket No. ER22-2029-000 et al. (October 31, 2022).
72 See 184 FERC ¶ 61,168.

Figure 13-21 Minimum tangible asset requirement changes under the revised tariff language if approved in 2026: 2025 through 2035



Treatment of Defaulted Portfolios

Under the method applied to the GreenHat default, when an FTR participant defaults on their positions, their portfolio remains in the FTR market and continues to accrue revenues and/or charges and must be reconciled. Under this method, PJM leaves the participant's positions unchanged, lets the positions settle at day-ahead prices, and charges any net losses to the default allocation assessment. This method exposes all members in PJM to an uncertain charge for the default allocation assessment that will not be known until those FTRs settle.

The MMU recommends that the defaulted FTRs be canceled rather than holding or liquidating them.[73] Canceling the FTRs would release the FTRs to the FTR market. The market would then decide the value of the capacity released and the timing of its release. There would be no discretion necessary to settle the defaulted position and the losses would be contained within the ARR/FTR market.

Cancellation of a defaulting portfolio does not change congestion. Cancellation of a defaulting portfolio can affect ARR/FTR funding as a result of changes in auction revenue, changes in the net target allocations, and potential simultaneous feasibility violations, while any collateral collected from the defaulted participant is available to offset losses from the cancelled FTRs. However, PJM can and does address similar issues routinely. PJM has tools available, such as the counter flow buyback and Stage 1A over allocation rules, and uses them regularly in the Annual FTR Auction, to improve funding as well as address feasibility concerns. Cancellation of FTRs would isolate the costs of the default to those participating in and benefitting from the FTR market.

FTR Forfeitures

By order issued January 19, 2017, the Commission determined that the FTR forfeiture rule is just and reasonable and "...serves to deter such manipulation" related to virtual transaction cross product manipulation.[74] The Commission identified four main tenets with which the Forfeiture Rule must comply, including that it: deter manipulation, provide transparency allowing participants to modify their behavior, base forfeitures on an individual participant's actions and is not punitive.[75]

The point of the FTR forfeiture rule is to avoid an inefficient and costly market power mitigation process and to establish an objective rule that prevents manipulation of the FTR market. The FTR forfeiture rule is designed to remove the incentive to engage in manipulation. The rule does not result in findings of manipulation.[76]

73 See Comments of the Independent Market Monitor for PJM, Docket No. ER18-2068-000 (August 16, 2018).

74 See 158 FERC ¶ 61,038 at P 33 (2017).

75 See *id.* at P 62.

76 *See* "Protest and Motion for Rejection of the Independent Market Monitor for PJM," Docket No. EL20-41 (June 1, 2020).

The FTR forfeiture rule considers the impact of a participant's net virtual transaction portfolio on all constraints.[77] If a participant's net virtual portfolio impacts a constraint by the greater of 0.1 MW or 10 percent or more of the constraint line limit, and that constraint affects an individual FTR's target allocation by $0.01 or more, the participant's net virtual portfolio increased the value of the FTR, and the FTR is subject to FTR forfeiture. The FTR forfeiture also requires that congestion on the FTR path in the day ahead market be greater than congestion on that path in the real time market.

The FTR forfeiture rule does not require FTR holders to pay penalties. The FTR forfeiture rule does not affect the profits or losses of virtual activity. The FTR forfeiture rule, if triggered by a participant's virtual portfolio, results in forfeiting only FTR profits and only in the specific hours for which the rule is violated. The profit is calculated as the hourly FTR target allocation minus the FTR's hourly cost. Even when FTR profits are forfeited, the value that the buyer assigned to congestion in the FTR auction (the price paid) is not affected. For example, if a buyer paid $5.00/MWh for congestion and congestion was $5.00/MWh, the forfeiture would be zero. If congestion were $7.00/MWh, the forfeiture would be $2.00/MWh. Market participants understand the relationship between FTR and virtual positions in detail and can avoid violating the FTR forfeiture rule if they choose to do so.

The FTR forfeiture rule is less effective than initially intended as a result of the element of the rule requiring that day-ahead congestion on the FTR path be greater than real-time congestion the same path. As a result of model differences, there is a significant opportunity for virtual participants to profit from differences between day-ahead and real-time prices without driving the prices together, termed false arbitrage. As a result, FTR holders can use virtual positions to make their FTR positions more valuable without violating the rule.

The FTR forfeiture rule has not reduced participation in the PJM FTR market or participation in virtual activity. There has been an increase in the number of participants in the FTR market since the implementation of the new FTR forfeiture rule, and a decrease in the number of participants with forfeitures.

77 A modified FTR forfeiture rule was implemented effective January 19, 2017. See *2019 Annual State of the Market Report for PJM*, Volume II, Section 13: Financial Transmission Rights for the full history.

On June 24, 2019, PJM implemented a new method to calculate the hourly cost of an FTR only for hours in which it is effective.[78] Beginning with the September 2019 bill, PJM began billing using the correct hourly cost calculation. For the 2020/2021 planning period, total FTR forfeitures were $4.6 million.

On May 20, 2021, FERC issued an order ruling the $0.01 definition of an increase in the value of an FTR unjust and unreasonable, but upheld the other parts of PJM's forfeiture rule.[79] In this order, FERC required PJM to modify the FTR forfeiture rule and submit a compliance filing. As a result, there was no FTR forfeiture rule in place from May 21, 2021 until February 1, 2022. These months have zero forfeiture in Figure 13-22.

On June 21, 2021, PJM filed a request for clarification, or alternatively rehearing.[80] PJM asked that FERC clarify the status of the forfeitures that were assessed over the four years between the initial FERC order for a compliance filing, and their order rejecting PJM's compliance filing. On July 19, 2021, PJM made a compliance filing to address FERC's concerns with the $0.01 element of the FTR forfeiture rule.[81] PJM's compliance filing eliminated that element and replaced it with a constraint based FTR forfeiture. The forfeiture is based on the increased value of each constraint that violates the rule, determined by the shadow price multiplied by the net dfax on that constraint. This change meets FERC's previously established criteria established under the initial FERC order and creates a more precise FTR forfeiture value, to meet the criteria established under the new FERC order.

On January 31, 2022, FERC accepted PJM's July 19, 2021 compliance filing to implement FTR forfeitures using a constraint based method, effective February 1, 2022.[82]

Figure 13-22 shows the monthly FTR forfeitures under the FTR forfeiture rules in effect from January 19, 2017, through March 31, 2026. As required by the FERC order, PJM began retroactively billing FTR forfeitures with the

78 *See* "Minor modification to Tariff Language for FTR Forfeiture Rule," Docket No. ER19-2240 (June 24, 2019).
79 See 175 FERC ¶ 61,137 (2021).
80 See Request for Clarification or, in the Alternative, Rehearing of PJM Interconnection, LLC, FERC Docket No. ER17-1433-000 (June 21, 2021).
81 *See* "FTR Forfeiture Rule Compliance Filing," FERC Docket No. ER17-1433 (July 19, 2021).
82 See 178 FERC ¶ 61,079, *reh'g denied*, 179 FERC ¶ 61,010 (2022), *affirmed*, XO Energy MA, LPC, et al. v. FERC, Case No. 22-1096 (D.C. Cir. January 24, 2023), *affirmed en banc*, XO Energy MA, LPC, et al. v. FERC, Case No. 22-1096 (D.C. Cir. September 13, 2023).

September 2017 bill. In the period from January 2017 through September 2017, participants did not have good information about the level of their FTR forfeitures, so they could not accurately modify their bidding behavior to avoid FTR forfeitures. After September 2017, participants received more timely information on their FTR forfeitures. Calculations of forfeitures under the new constraint specific rule from February 1, 2022, through March 31, 2026, are included in Figure 13-22.

Figure 13-22 Monthly FTR forfeitures for physical and financial participants: January 2017 through March 2026[83]

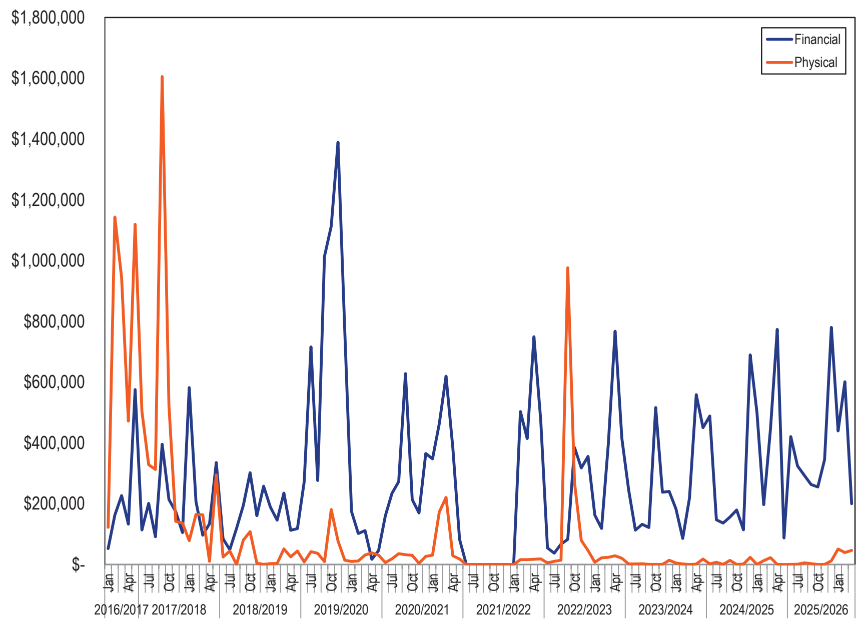


Table 13-56 shows the monthly FTR forfeitures by organization type for the 2024/2025 planning period and the first ten months of the 2025/2026 planning period. For the first ten months of the 2025/2026 planning period there were $4,082,718 in FTR forfeitures, up 30.1 percent from $3,138,663 in the same period of the 2024/2025 planning period. Financial participants accounted for 96.1 percent of all FTR forfeitures for the ten months of the 2025/2026 planning period, down 1.2 percentage points from 97.3 percent in the same period of the 2024/2025 planning period.

Table 13-56 Monthly FTR forfeitures by organization type: June 2024 through March 2026[84]

	Organization Type		
Month	Physical	Financial	Total
Jun-24	$2,062.39	$488,478.10	$490,540.49
Jul-24	$7,263.55	$147,024.31	$154,287.86
Aug-24	$265.40	$136,407.60	$136,672.99
Sep-24	$13,609.35	$155,922.29	$169,531.63
Oct-24	$153.22	$179,545.06	$179,698.29
Nov-24	$1,159.23	$114,091.82	$115,251.06
Dec-24	$23,393.12	$689,808.14	$713,201.26
Jan-25	$538.39	$500,477.32	$501,015.71
Feb-25	$12,543.78	$197,063.07	$209,606.85
Mar-25	$22,717.56	$446,139.20	$468,856.76
Apr-25	$638.34	$773,771.75	$774,410.09
May-25	$17.41	$87,239.94	$87,257.35
Summary for 2024/2025 Planning Period			
Total	$84,361.73	$3,915,968.60	$4,000,330.34
Jun-25	$615.50	$420,868.10	$421,483.61
Jul-25	$1,055.22	$324,455.09	$325,510.31
Aug-25	$5,596.14	$293,350.91	$298,947.05
Sep-25	$3,094.75	$263,182.16	$266,276.91
Oct-25	$0.00	$255,200.29	$255,200.29
Nov-25	$465.72	$344,978.68	$345,444.39
Dec-25	$12,240.88	$780,149.87	$792,390.75
Jan-26	$51,030.21	$439,411.04	$490,441.25
Feb-26	$39,391.25	$601,523.72	$640,914.97
Mar-26	$46,221.46	$199,886.87	$246,108.33
Summary For 2025/2026 Planning Period*			
Total	$159,711.12	$3,923,006.74	$4,082,717.87

*First ten months of the 2025/2026 plannning period

83 This figure is affected by the identified distribution factor error.

84 This table is affected by the identified distribution factor error.