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 $232.2 million, 149.3 percent, from $155.6 million in the first six months of 2025 to $387.8 million in the first six months of 2026, primarily due to increases in capacity market revenue. Emergency demand response revenue accounted for 85.0 percent of all demand response revenue, economic demand response for 4.8 percent, demand response in the synchronized reserve market for 2.5 percent and demand response in the regulation market for 7.7 percent.
- Total emergency demand response revenue increased by $208.6 million, 172.3 percent, from $121.1 million in the first six months of 2025 to $329.7 million in the first six months of 2026.[2] This increase was primarily a result of higher capacity market prices and capacity market revenue.
- Economic demand response revenue increased by $2.2 million, 13.7 percent, from $16.2 million in the first six months of 2025 to $18.4 million in the first six months of 2026.[3] Demand response revenue in the synchronized reserve market increased by $0.6 million, 5.7 percent, from $9.1 million in the first six months of 2025 to $9.7 million in the first six months of 2026. Demand response revenue in the regulation market increased by $20.9 million, 228.4 percent, from $9.1 million in the first six months of 2025 to $30.0 million in the first six 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 six months of 2025 and 2026. The HHI for economic demand response resource reductions increased by 148 points from 8631 in the first six months of 2025 to 8779 in the first six months of 2026.
- The ownership of emergency demand response resources is highly concentrated. The HHI for emergency demand response resources committed MW was 2517 for the 2025/2026 Delivery Year. In the 2025/2026 Delivery Year, the four largest CSPs owned 86.7 percent of all committed emergency demand response UCAP MW. The HHI for emergency demand response committed MW is 3131 for the 2026/2027 Delivery Year. In the 2026/2027 Delivery Year, the four largest CSPs own 89.2 percent of all committed demand response UCAP MW.
- **Limited Locational Dispatch of Demand Resources.** 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.

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 July 14, 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).

- **Energy Efficiency.** Energy efficiency payments were eliminated from PJM markets effective June 1, 2026.

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.)
- 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.)

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).

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 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.)
- 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 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

7 See ISO-NE Tariff, Section III, Market Rule 1, Appendix E1 and Appendix E2, "Demand Response," <https://www.iso-ne.com/participate/rules-procedures/tariff/market-rule-1>. (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.

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.

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.)

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.

- 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.)
- The MMU recommends that CSPs be required to provide metered data to PJM within 24 hours following the dispatch of economic or emergency DR. (Priority: Medium. New recommendation. 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 in 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.

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 minus 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 is measured relative to either Peak Load Contribution (PLC) or Winter Peak Load (WPL), 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.

11 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).

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.

Under the MMU's recommended approach, 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. [12] [13] [14] 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

12 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. See the MMU package within the *SODRSTF Matrix*, <https://www.pjm.com/-/media/DotCom/committees-groups/task-forces/sodrstf/20180815/20180815-item-04-sodrstf-matrix.xls>.

13 The MMU proposal was based on the concepts defined in the BGE load forecasting program and the Pennsylvania Act 129 Utility Program. ***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).

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]

16 577 U.S. 260 (2016).

This approach would 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, or at any time demand resources are called on, 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 at a level equal to the PLC minus the metered load even though it took no action. If the load at a demand resource location actually increased above the PLC when called to reduce its demand, that increase would be set to zero and ignored. If the load at a demand resource location increased when called to reduce but remained below the PLC, the resources would be credited with a reduction from the PLC to that increased MWh level. The standard reporting of demand side response is therefore misleading because it includes loads that were already lower for any reason as a response, because it credits increases in load as a response, and because it ignores and zeros out increases in load above the PLC. 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.

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 Attachment DD § 5.5A		OATT Attachment K § 1.5A	
Market	Capacity Only OATT Attachment K § 8.1	Full Program Option (Capacity and Energy) OATT Attachment K § 8.1	Energy Only OATT Attachment 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

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

Non-PJM Demand Response Programs

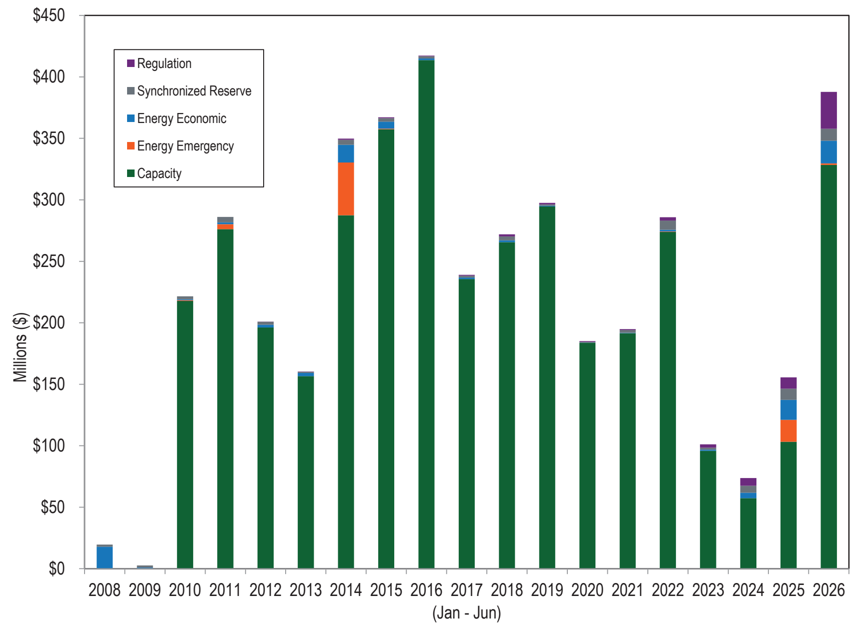
Within the PJM footprint, states may have additional demand response programs as part of a Renewable Portfolio Standard (RPS) or a separate program. Indiana, Ohio, Pennsylvania (e.g. Pennsylvania ACT 129 Utility Program) and North Carolina include demand response in their RPS. If demand response is dispatched by a state run program, the demand response resources are ineligible to receive payments from PJM during the state dispatch.[18] 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 in PJM programs. [19] [20]

PJM Demand Response Programs

Figure 6-1 shows all revenue from PJM demand response programs by market for each year, 2008 through June 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 six months of 2026, total demand response revenue increased by $232.2 million, 149.3 percent, from $155.6 million in the first six months of 2025 to $387.8 million in the first six months of 2026, primarily due to increases in capacity market prices and revenue. Total emergency demand response revenue increased by $208.6 million, 172.3 percent, from $121.1 million in the first six months of 2025 to $329.7 million in the first six months of 2026. This increase was a result of higher capacity market prices and capacity market revenue.[22] In the first six months of 2026, emergency demand response revenue, which includes capacity and emergency energy revenue, accounted for 85.0 percent of all revenue received by demand response providers, the economic program for 4.8 percent, synchronized reserve for 2.5 percent and the regulation market for 7.7 percent.

Economic demand response revenue increased by $2.2 million, 13.7 percent, from $16.2 million in the first six months of 2025 to $18.4 million in the first six months of 2026.[23] Demand response revenue in the synchronized reserve market increased by $0.6 million, 5.7 percent, from $9.1 million in the first six months of 2025 to $9.7 million in the first six months of 2026. Demand response revenue in the regulation market increased by $20.9 million, 228.4 percent, from $9.1 million in the first six months of 2025 to $30.0 million in the first six months of 2026.

Figure 6-1 Demand response revenue by market: January through June, 2008 to 2026



18 "PJM Manual 11: Energy & Ancillary Services Market Operations," § 10.1, Rev. 136 (October 1, 2025).

19 *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).

20 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.

21 This includes both capacity market revenue and emergency energy revenue for capacity resources.

22 The total credits and MWh for demand resources were downloaded as of July 14, 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 shows the monthly demand response cleared volumes and revenues in the synchronized reserve market.

Table 6-2 Demand response synchronized reserve market MWh and revenue: January 2025 through June 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	300,474	32.8%	$2,013,303.75	$1,054,282.74	(47.6%)
May	404,918	389,418	(3.8%)	$1,673,752.10	$1,377,980.14	(17.7%)
Jun	415,556	286,499	(31.1%)	$2,119,535.48	$1,047,664.26	(50.6%)
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-Jun)	1,766,638	1,988,743	12.6%	$9,133,060.00	$9,657,572.77	5.7%

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 June 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	43,600	26.7%	$1,107,759.21	$4,285,014.96	286.8%
May	35,331	41,381	17.1%	$1,148,378.85	$3,679,069.14	220.4%
Jun	34,489	40,019	16.0%	$1,643,056.35	$5,142,131.47	213.0%
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-Jun)	210,259	255,167	21.4%	$9,145,688.61	$30,036,002.39	228.4%

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 June, 2026

Method	MW	Percent
Generator	124.2	5.8%
HVAC	73.8	3.4%
Lighting	158.3	7.4%
Refrigeration	14.9	0.7%
Manufacturing	1,049.7	48.8%
Water Heaters	0.0	0.0%
Batteries	14.1	0.7%
Plug Load	3.9	0.2%
Computing	712.9	33.1%
Total	2,151.8	100.0%

Table 6-5 shows the demand response capability registered to provide regulation by load reduction method.

Table 6-5 Demand response regulation load reduction methods: January through June, 2026

Method	MW	Percent
Water Heaters	146.3	54.4%
Batteries	122.6	45.6%
Total	268.9	100.0%

24 "PJM Manual 11: Energy & Ancillary Services Market Operations," § 10.2.2, Rev. 136 (October 1, 2025).

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 that has environmental restrictions that restrict the number of hours the generator can operate to a defined number of hours, generally only 100 hours.[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.

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.

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.

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, 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, if the area dispatched is not a defined subzone 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.

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). 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. The change was endorsed at the April 25, 2024, Markets and Reliability Committee meeting <https://www.pjm.com/-/media/DotCom/committees-groups/committees/mrc/2024/20240425/20240425-mrc-summarized-voting-report---updated.pdf>.
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.

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 2025/2026 Delivery Year, with an HHI value of 2517. In the 2025/2026 Delivery Year, the four largest companies contributed 86.7 percent of all committed demand response UCAP MW. The HHI for demand resources shows that ownership is highly concentrated for the 2026/2027 Delivery Year, with an HHI value of 3131. In the 2026/2027 Delivery Year, the four largest companies own 89.2 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 2026/2027

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%
2026/2027	3131	Highly Concentrated	89.2%

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: 2025/2026 and 2026/2027 Delivery Years[30]

Delivery Year	LDA	Committed UCAP MW	HHI Value	HHI Concentration
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
2026/2027	ATSI	503.4	2956	High
	ATSI-CLEVELAND	94.4	3620	High
	BGE	152.2	4022	High
	COMED	970.7	3885	High
	DAY	152.0	5341	High
	DEOK	116.3	6340	High
	DOM	555.1	2759	High
	DPL-SOUTH	33.9	6072	High
	EMAAC	347.8	4532	High
	JCPL	59.2	3829	High
	MAAC	282.1	3858	High
	PEPCO	229.3	3947	High
	PPL	327.5	3669	High
	PS-NORTH	45.6	3582	High
	PSEG	133.5	4788	High
	RTO	1,707.3	2888	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 555.6 MW, or 8.9 percent, from 6,265.9 MW in the 2025/2026 Delivery Year to 5710.3 MW in the 2026/2027 Delivery Year. The DR percent of capacity decreased by 0.4 percentage points, from 4.5 percent in the 2025/2026 Delivery Year to 4.1 percent in the 2026/2027 Delivery Year.

Table 6-8 Cleared Demand Resource UCAP MW: 2007/2008 through 2026/2027 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%
2026/2027	5,710.3	137,803.1	4.1%

Table 6-9 shows zonal monthly capacity market revenue to demand resources for 2025. Capacity market revenue increased in the first six months of 2026 by $225.2 million, 218.1 percent, from $103.2 million in the first six months of 2025 to $328.4 million in the first six months of 2026. RPM revenues in the first six months of 2026 differed from the same period in 2025 due to the significant increase in capacity market clearing prices across the delivery years. Revenues during the first five months of 2025 were associated with the 2024/2025 Delivery Year while the same period in 2026 was associated with the 2025/2026 Delivery Year. The RTO clearing price in the 2024/2025 BRA was $28.92/MW-Day, $269.92/MW-Day in the 2025/2026 BRA, and $329.17/MW-Day in the 2026/2027 Delivery Year. Revenues in June 2025 were the result the 2025/2026 Delivery Year clearing prices while revenues in June 2026 were the result of the 2026/2027 Delivery Year clearing prices.

Table 6-9 Zonal monthly demand resource capacity revenue: January through June, 2026

Zone	January	February	March	April	May	June	Total
ACEC	$342,232	$309,113	$342,232	$331,192	$342,232	$311,066	$1,978,067
AEP, EKPC	$8,730,837	$7,885,917	$8,730,837	$8,449,197	$8,730,837	$10,906,112	$53,433,738
APS	$4,102,594	$3,705,569	$4,102,594	$3,970,252	$4,102,594	$4,960,263	$24,943,865
ATSI	$6,242,317	$5,638,222	$6,242,317	$6,040,952	$6,242,317	$5,470,121	$35,876,245
BGE	$2,446,970	$2,210,167	$2,446,970	$2,368,036	$2,446,970	$1,487,690	$13,406,803
COMED	$8,268,950	$7,468,729	$8,268,950	$8,002,210	$8,268,950	$8,855,990	$49,133,780
DAY	$1,181,327	$1,067,005	$1,181,327	$1,143,220	$1,181,327	$1,490,160	$7,244,365
DOM	$9,275,482	$8,377,855	$9,275,482	$8,976,273	$9,275,482	$5,479,693	$50,660,269
DPL	$981,511	$886,526	$981,511	$949,849	$981,511	$1,039,848	$5,820,754
DUKE	$1,335,456	$1,206,219	$1,335,456	$1,292,377	$1,335,456	$1,134,649	$7,639,614
DUQ	$738,183	$666,746	$738,183	$714,370	$738,183	$845,854	$4,441,518
JCPLC	$842,610	$761,067	$842,610	$815,429	$842,610	$584,606	$4,688,931
MEC	$1,137,983	$1,027,855	$1,137,983	$1,101,274	$1,137,983	$1,209,700	$6,752,777
PE	$1,770,232	$1,598,920	$1,770,232	$1,713,128	$1,770,232	$1,566,691	$10,189,436
PECO	$2,470,426	$2,231,352	$2,470,426	$2,390,735	$2,470,426	$2,241,161	$14,274,526
PEPCO	$1,052,969	$951,068	$1,052,969	$1,019,002	$1,052,969	$1,033,927	$6,162,903
PPL	$3,559,375	$3,214,920	$3,559,375	$3,444,557	$3,559,375	$3,196,103	$20,533,706
PSEG	$1,915,325	$1,729,971	$1,915,325	$1,853,541	$1,915,325	$1,766,656	$11,096,144
REC	$19,245	$17,383	$19,245	$18,625	$19,245	$11,850	$105,594
TOTAL	$56,414,025	$50,954,603	$56,414,025	$54,594,218	$56,414,025	$53,592,140	$328,383,035

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 2025/2026 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 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 6-10 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	15,990	99.1%	141	0.9%	16,131	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	20,861	99.1%	196	0.9%	21,057	100.0%

Table 6-11 shows the amount of nominated MW and locations by product type and lead time for the 2026/2027 Delivery Year. PJM approved 3,601 locations, or 12.9 percent of all locations, which have 3,418.1 nominated MW, or 47.1 percent of all nominated MW, for exceptions to the 30 minute lead time rule for the 2026/2027 Delivery Year.

Table 6-11 Nominated MW and locations by product type and lead time: 2026/2027 Delivery Year

	Pre-Emergency		Emergency			
Lead Type	MW	Percent	MW	Percent	Total	Percent of Total
30 Minutes	3,684.4	95.9%	157.7	4.1%	3,842.1	52.9%
60 Minutes	391.3	90.3%	42.0	9.7%	433.3	6.0%
120 Minutes	2,761.2	92.5%	223.6	7.5%	2,984.8	41.1%
Total	6,836.9	94.2%	423.2	5.8%	7,260.2	100.0%

	Pre-Emergency		Emergency			
Lead Type	Locations	Percent	Locations	Percent	Total	Percent of Total
30 Minutes	24,104	99.1%	207	0.9%	24,311	87.1%
60 Minutes	479	93.0%	36	7.0%	515	1.8%
120 Minutes	3,007	97.4%	79	2.6%	3,086	11.1%
Total	27,590	98.8%	322	1.2%	27,912	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,

31 OATT Attachment DD-1, Section A.2(a).

- 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 2026/2027 Delivery Year.[32]

Table 6-12 Nominated MW and locations of granted lead time exceptions: 2026/2027 Delivery Year

	60 Minutes		120 Minutes			
Reason	MW	Percent	MW	Percent	Total	Percent
Generation Start Time	54.5	1.6%	427.8	12.5%	482.4	14.1%
Manufacturing Damage	163.2	4.8%	1,557.5	45.6%	1,720.7	50.3%
Safety Problem	215.6	6.3%	999.5	29.2%	1,215.1	35.5%
Total	433.3	12.7%	2,984.8	87.3%	3,418.1	100.0%

	60 Minutes		120 Minutes			
Reason	Locations	Percent	Locations	Percent	Total	Percent
Generation Start Time	46	1.3%	189	5.2%	235	6.5%
Manufacturing Damage	253	7.0%	955	26.5%	1,208	33.5%
Safety Problem	216	6.0%	1,942	53.9%	2,158	59.9%
Total	515	14.3%	3,086	85.7%	3,601	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 2026/2027 Delivery Year.

Table 6-13 Nominated MW and locations by business segment: 2026/2027 Delivery Year

Business Segment	Nominated MW (ICAP)	Percent of Total	Locations	Percent of Total
Industrial/Manufacturing	3,142.7	43.3%	3,515	12.6%
Schools	755.2	10.4%	4,249	15.2%
Transportation, Communications, Electric, Gas and Sanitary Services	609.8	8.4%	572	2.0%
Office Building	530.2	7.3%	1,387	5.0%
Services	386.7	5.3%	827	3.0%
Hospitals	361.7	5.0%	393	1.4%
Residential	357.7	4.9%	9,040	32.4%
Retail Service	336.7	4.6%	7,200	25.8%
Data Center	242.0	3.3%	37	0.1%
Mining	239.5	3.3%	149	0.5%
Data Center with Crypto Mining	135.8	1.9%	24	0.1%
Agriculture, Forestry and Fishing	94.9	1.3%	260	0.9%
Multiple Dwelling Unit	35.4	0.5%	209	0.7%
Correctional Facilities	31.7	0.4%	50	0.2%
Total	7,260.2	100.0%	27,912	100.0%

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).

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 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

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 LDA common to the aggregated resources.
40 OATT Attachment DD § 5.11.
41 OATT Attachment M-2.

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]

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 was 77 percent.[45] The ELCC class rating for Demand Resources for the 2026/2027 BRA was 69 percent.[46]

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.[47] This overstatement of performance occurred during Winter Storm Elliott and continues through the first six months of 2026. 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.

PJM proposed a set of significant changes to the treatment of demand side resources that were accepted by FERC.[48] Demand response capacity availability hours now includes all hours rather than a limited number of hours. The level of demand resources is now based on the coincident peak demand of the resources rather than the sum of noncoincident peak demands. The extension of demand resource availability to all hours, consistent with all other capacity resources is logical. Defining all DR MW for the same coincident peak demand hour is a more logical measure of the level of actual DR potential. The prior practice of adding together all the DR from individual non coincident peak hours resulted in an overstatement of demand resources.

PJM increased the ELCC derating factor from 76 percent to 94 percent, an increase of 24 percent in the value of demand resource MW. PJM's ELCC value for DR is not consistent with the method PJM uses for generation resources. PJM's ELCC for DR is based on assumed behavior and not based on the actual performance of demand resources during the same high EUE (expected

42 162 FERC ¶ 61,159 (2018).
43 See PJM, Intra-PJM Tariffs, RAA, Schedule 6 (18.0.0), § 6.l.
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 "*BRA ELCC Class Rating for 2025/2026,*" <https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/2025-26-3ia-elcc-class-ratings.pdf> (March 12, 2025).
46 See "*2025 PJM Effective Load Carrying Capability and Reserve Requirement Study (ELCC/RRS),*" <https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/2025-pjm-elcc-rrs.pdf> (January 30, 2026).
47 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).
48 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>.

unserved energy) hours used for other capacity resources. The current ELCC value for demand response is already overstated.

As currently defined, 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.[49] 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.

PJM's changes will 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.[50] The changes 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 make consistent changes to the treatment of demand resources in the summer. PJM made 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 also affects the ELCC of other classes and makes PJM appear to be more reliable than it is.

49 See PJM Manual 13: Emergency Operations, §2.3.2. Rev. 98 (June 24, 2026).

50 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).

PJM filed these changes on March 6, 2025, in Docket No. ER25-1525-000.[51] The MMU filed an answer and motion for leave to answer on April 14, 2025.[52] On May 5, 2025, in Docket No. ER25-1525-000, FERC accepted PJM's filing 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.[53]

51 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).

52 See "Answer and Motion for Leave to Answer," Docket No. ER25-1525-000 (April 14, 2025).

53 191 FERC ¶ 61,103

Table 6-14 shows the MW registered by measurement and verification method and by technology type for the 2026/2027 Delivery Year. For the 2026/2027 Delivery Year, 99.77 percent of the MW use the FSL method and 0.23 percent of the MW use the GLD measurement and verification method.

Table 6-14 Nominated MW by each demand response method: 2026/2027 Delivery Year

Measurement and Verification Method	On-site Generation MW	HVAC MW	Refrigeration MW	Lighting MW	Technology Type Manufacturing MW	Water Heating MW	Batteries or Plug Load MW	Computing MW	Total	Percent by type
Firm Service Level	1,305.8	1,913.9	172.6	656.8	3,007.2	16.1	62.0	109.4	7,243.8	99.77%
Guaranteed Load Drop	15.5	0.8	0.0	0.0	0.1	0.0	0.0	0.0	16.4	0.23%
Total	1,321.3	1,914.7	172.6	656.8	3,007.3	16.1	62.0	109.4	7,260.2	100.0%
Percent by method	18.2%	26.4%	2.4%	9.0%	41.4%	0.2%	0.9%	1.5%	100.0%	

Table 6-15 shows the fuel type used in the onsite generators for the 2026/2027 Delivery Year in the emergency and pre-emergency programs. For the 2026/2027 Delivery Year, 1,321.3 MW of the 7,260.2 nominated MW, 18.2 percent, used onsite generation. Of the 1,321.3 MW, 79.3 percent used diesel and 20.7 percent used natural gas, gasoline, oil, propane or waste products. These 1,321.3 MW of DR registrations rely on behind the meter generation with environmental restrictions that limit the resource's ability to operate to 100 hours per year. Demand resources relying on behind the meter generation with environmental restrictions that limit the resource's ability to operate must register as emergency DR. EPA regulations require that Reciprocating Internal Combustion Engines (RICE) that do not meet EPA emissions standards 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. There is no reason to believe that PJM emergency conditions will always be less than 100 hours per year. PJM does not prevent 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 identify Reciprocating Internal Combustion Engines (RICE) generators, only whether it is an internal combustion engine. 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 because its available hours are limited as a result of emissions standards.

Table 6-15 Onsite generation fuel type (MW): 2026/2027 Delivery Year

Fuel Type	2026/2027 MW	Percent
Diesel	1,047.8	79.3%
Natural Gas, Gasoline, Oil, Propane, Waste Products	273.5	20.7%
Total	1,321.3	100.0%

Table 6-16 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 use the FSL method and 0.25 percent use the GLD measurement and verification method.

Table 6-16 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	Batteries and Plug Load MW	Computing MW	Total	Percent by type
Firm Service Level	1,265.6	1,896.2	202.6	791.3	3,659.6	22.0	39.1	102.8	7,979.2	99.75%
Guaranteed Load Drop	5.1	1.1	0.0	0.0	14.1	0.0	0.0	0.0	20.3	0.25%
Total	1,270.7	1,897.3	202.6	791.3	3,673.7	22.0	39.1	102.8	7,999.6	100.0%
Percent by method	15.9%	23.7%	2.5%	9.9%	45.9%	0.3%	0.5%	1.3%	100.0%	

Table 6-17 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, 1,270.7 MW of the 7,999.6 nominated MW, 15.9 percent, use onsite generation. Of the 1,270.7 MW, 83.4 percent use diesel and 16.6 percent use natural gas, gasoline, oil, propane or waste products.

Table 6-17 Onsite generation fuel type (MW): 2025/2026 Delivery Year

	2025/2026	
Fuel Type	MW	Percent
Diesel	1,059.2	83.4%
Natural Gas, Gasoline, Oil, Propane, Waste Products	211.5	16.6%
Total	1,270.7	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.[54] 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.[55] 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.

54 OATT Attachment DD, § 11.
55 See "Load Management Subzones," <https://www.pjm.com/-/media/markets-ops/demand-response/subzone-definition-workbook.ashx> (Accessed January 13, 2023).

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.[56] 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 allowing emergency DR to set price.[57] 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.[58]

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.[59]

Under the capacity performance design of the capacity market, compliance for potential penalties is measured for DR only during performance assessment intervals (PAI).[60]

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).[61]

Table 6-18 shows the amount of nominated demand response MW, the required reserve margin and actual reserve margin for the 2025/2026 and 2026/2027 Delivery Years. There are 8,275.8 nominated MW of demand response for the 2026/2027 Delivery Year, 30.7 percent of the required reserve margin and 31.1 percent of the actual reserve margin for the 2026/2027 Delivery Year.[62]

Table 6-18 Demand response nominated MW compared to reserve margin: 2025/2026 and 2026/2027 Delivery Years[63]

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
2025/2026	8,137.5	25,381.0	32.1%	25,090.8	32.4%
2026/2027	8,275.8	26,965.7	30.7%	26,607.0	31.1%

56 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) <https://www.ferc.gov/sites/default/files/2020-08/M2-3-XIAO.pdf> .

57 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.

58 "PJM Manual 18: PJM Capacity Market," § 2.3.1, Rev. 62 (December 17, 2025).

59 "PJM Manual 18: PJM Capacity Market," § 8.7A, Rev. 62 (December 17, 2025).

60 OATT § 1 (Performance Assessment Hour).

61 See "Order Accepting Tariff Revisions Subject to Condition," Docket No. ER23-1996-000 (July 28, 2023).

62 See *2025 Annual State of the Market Report for PJM*, Volume 2, Section 5: Capacity Market, Table 5-7.

63 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.

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).[64] [65] A CAA is an electrically connected area that has 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.[66]

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.[67] 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.[68]

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

64 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.

65 PJM. "Manual 18: Capacity Market," § 8.7.2, Rev. 62 (December 17, 2025).

66 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).

67 157 FERC ¶ 61,067 (2016).

68 PJM. "Manual 11: Energy & Ancillary Services Market Operations," § 10.2.5, Rev. 136 (October 1, 2025).

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 as long as the location has an active EDC account and a meter. This is a violation of the logic of demand side resources and such customers should not be permitted to be included as registered demand resources. In addition, 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 such a 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.

This inclusion of resources violates the definition of demand resources which requires that 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."[69] Such customers no longer have 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.[70] 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.[71] 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.[72]

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.[73] 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.[74]

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.[75] 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

69 OA Schedule 1 § 8.2.
70 There was one proposal from PJM, one proposal from a market participant and one proposal from the MMU. See *Draft Minutes from the Market Implementation Committee,* <https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/20170712/20170712-item-02-draft-minutes-20170607.pdf> .

71 "PJM Manual 11: Energy & Ancillary Services Market Operations," § 10.4.1, Rev. 136 (October 1, 2025).
72 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.
73 See "Order Denying Complaint re Enerwise Global Technologies, LLC v. PJM Interconnection," EL23-104-000 (July 28, 2023).
74 *Id*, Commissioner Chang Statement Concurring at 1.
75 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).

adequacy and to correctly determine efficient capacity market prices through supply and demand in the market. [76]

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.[77]

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.[78] 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 retests 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.[79] 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.

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.[80] 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

76 See "Comments of the Independent Market Monitor for PJM," Docket No. EL26-4-000 (October 28, 2025).
77 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).
78 "PJM Manual 18: PJM Capacity Market," § 8.7, Rev. 62 (December 17, 2025).
79 See "Demand Response Test Schedule," <https://www.pjm.com/markets-and-operations/demand-response/m/demand-response-test-schedule> (Accessed July 22, 2026).
80 "PJM Manual 18: PJM Capacity Market," § 8.7, Rev. 62 (December 17, 2025).

have the same obligation to perform when called upon, regardless of whether the dispatch event occurs as part of a PAI or not.[81] There is no reason therefore to allow CSPs the optionality of testing in lieu of using non-PAI event performance.

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.[82] 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.[83] 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 OATT Attachment K, § 8.5.
82 "PJM Manual 18: PJM Capacity Market," § 9.1.6, Rev. 62 (December 17, 2025).
83 "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.[84] There are 98.9 percent of nominated MW for the 2026/2027 Delivery Year registered under the full program option. There are 1.1 percent of nominated MW for the 2026/2027 Delivery Year registered as capacity only option. 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.”[85] PJM interprets the scarcity pricing rules to allow a maximum DR energy price of $1,849 per MWh for the 2021/2022 Delivery Year.[86] [87] 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.[88] 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.[89]

84 *Id.*
85 161 FERC ¶ 61,153 at P 8 (2017).

86 139 FERC ¶ 61,057 (2012).
87 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.
88 OATT Attachment K Appendix § 1.10.1A Day-Ahead Energy Market Scheduling (d) (x).
89 “PJM Manual 15: Cost Development Guidelines,” § 8.1, Rev. 47 (Oct. 1, 2025).

Table 6-21 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, had 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 had the highest average at $175.34 per location, while the shutdown cost of resources with $1,000 to $1,275 per MWh strike prices had the highest average at $87.63 per nominated MW .

Table 6-21 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	4,461	21.5%	3,789.2	47.9%	$74.44	$87.63
$1,275-$1,550	447	2.2%	497.1	6.3%	$0.21	$0.19
$1,550-$1,849	15,740	76.0%	3,460.8	43.8%	$11.15	$50.69
Total	20,707	100.0%	7,903.3	100.0%	$25.01	$65.53

Table 6-22 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices for the 2026/2027 Delivery Year. The majority of participants, 86.8 percent of locations and 51.2 percent of nominated MW, have a minimum dispatch price between $1,550 and $1,849 per MWh, the maximum price allowed for the 2026/2027 Delivery Year. Almost all registrations, 99.9 percent of locations and 98.9 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 have the highest average at $98.28 per location and $101.26 per nominated MW.

Table 6-22 Distribution of registrations and associated MW in the full option across ranges of minimum dispatch: 2026/2027 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	30	0.1%	77.5	1.1%	$0.00	$0.00
$1,000-$1,275	3,088	11.2%	2,997.0	41.7%	$98.28	$101.26
$1,275-$1,550	514	1.9%	431.4	6.0%	$0.18	$0.21
$1,550-$1,849	23,949	86.8%	3,673.5	51.2%	$6.75	$44.02
Total	27,581	100.0%	7,179.5	100.0%	$16.87	$64.81

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.[90] 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.

90 "PJM Manual 18: PJM Capacity Market," § 3A.3, Rev. 62 (December 17, 2025).

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.[91] Table 6-23 shows the Nominated MW of Price Responsive Demand for the 2020/2021 through 2026/2027 Delivery Years.

Table 6-23 Nominated MW of price responsive demand: 2020/2021 through 2026/2027 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
2026/2027	115.0	115.0	0.0	115.0	0.0	0.0	115.0

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:[92]

$$
\begin{aligned}
&\textit{PRD Credit}\\
&= [(\textit{Share of Zonal Nominal PRD Value committed in Base Residual Auction}\\
&* (\textit{Zonal Weather}\\
&- \textit{Normalized Peak Load for the summer concluding prior to the commencement of the Delivery Year}\\
&/\ \textit{Final Zonal Peak Load Forecast for the Delivery Year})\\
&* \textit{Final Zonal RPM Scaling Factor} * \textit{FPR} * \textit{Final Zonal Capacity Price})\\
&\\
&\textit{plus}\\
&\\
&(\textit{Share of Zonal Nominal PRD Value committed in Third Incremental Auction}\\
&* (\textit{Zonal Weather}\\
&- \textit{Normalized Peak Load for the summer concluding prior to the commencement of the Delivery Year}\\
&/\ \textit{Final Zonal Peak Load Forecast for the Delivery Year})\\
&* \textit{Final Zonal RPM Scaling Factor} * \textit{FPR} * \textit{Final Zonal Capacity Price}\\
&* \textit{Third Incremental Auction Component of Final Zonal Capacity Price stated as a Percentage})]
\end{aligned}
$$

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 2026/2027 Delivery Years.[93]

Table 6-24 PRD Credits for 2020/2021 through 2026/2027 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	$30,460,192.15
2026/2027	$1,101,918.87

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:

$$
\begin{aligned}
&\textit{PRD Commitment Compliance Penalty}\\
&\qquad = \textit{MW shortfall in the Sub} - \textit{zone/ Zone}\\
&\qquad * \textit{Delivery Year Forecast Pool Requirement}\\
&\qquad * \textit{PRD Commitment Compliance Penalty Rate}
\end{aligned}
$$

91 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>.

92 PJM. "Manual 18: Capacity Market," § 9.4.4, Rev. 62 (December 17, 2025).

93 The total credits for PRD were downloaded as of July 8, 2026, and may change as a result of continued PJM billing updates.

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 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.[94] 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.[95] 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.[96]

The PRD rules fall short of defining an effective and efficient product that is aligned with the definition of a capacity resource.[97] PJM's initial filing was rejected by the Commission based on the MMU's comments and PJM's modified filing was accepted.[98] 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.[99]

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

94 See "Proposed Amendments to Price Response Demand Rules", Docket No. ER19-1012-000 (Feb. 7, 2019).

95 167 FERC ¶ 61,268

96 See the *2023 Quarterly State of the Market Report for PJM: January through June,* Section 6: Demand Response, Table 6--49.

97 See "Compliance Filing Regarding Price Responsive Demand Rules," Docket No. ER20-271-001 (February 28, 2020).

98 See "Order Rejecting Tariff Revisions," Docket No. ER19-1012-000 (June 27, 2019).

99 October 31 Filing, Attachment B, Proposed Revised OATT § 10A (c).

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 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.[100]

Table 6-25 shows the deployment and release times, by lead time, for January 25, 2026.

Table 6-25 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.

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

100 OATT Attachment K, Section 8.5.

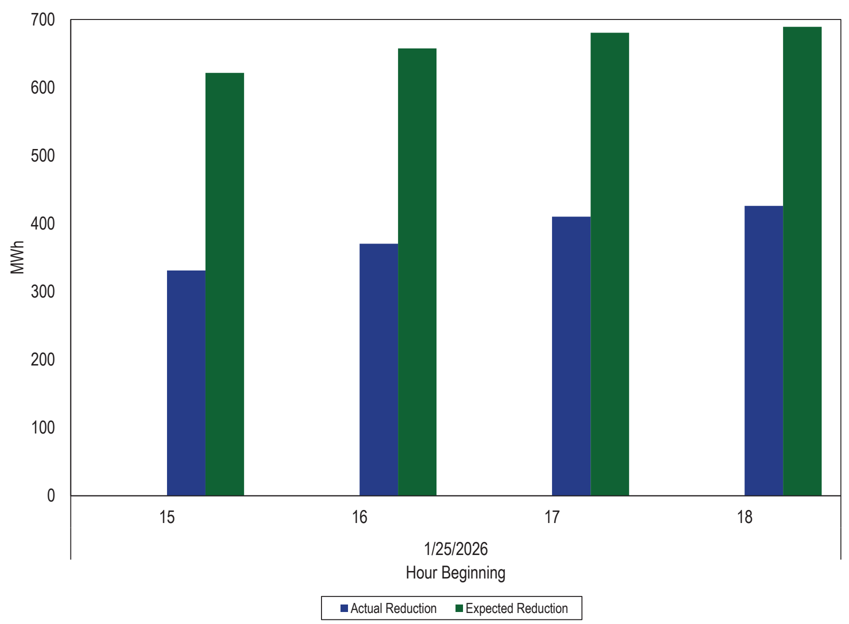
of their expected reduction on January 25, 2026.[101] Table 6-26 summarizes these results.

Table 6-26 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%

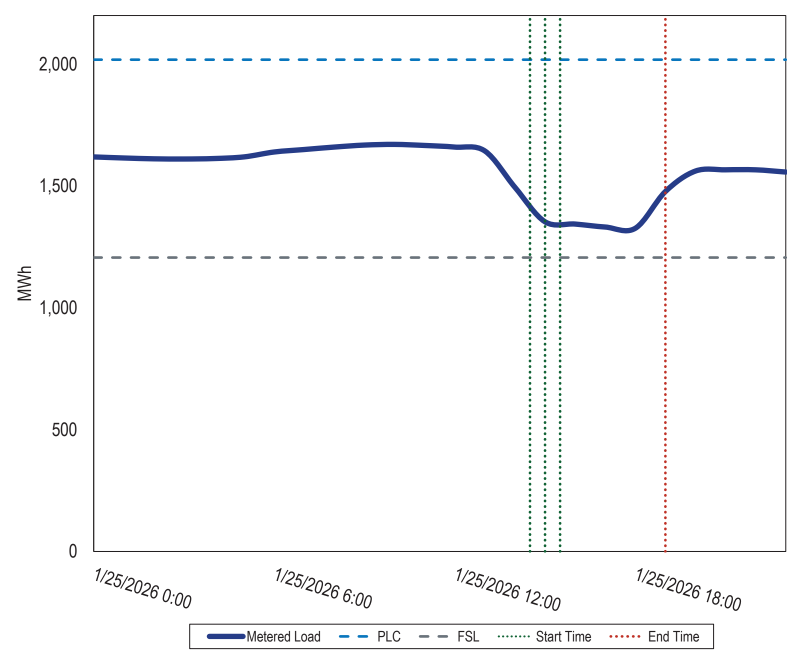
Figure 6-2 shows the hourly expected and actual reduction values for January 25, 2026.

Figure 6-2 Hourly demand resource expected and actual performance: 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 6-3 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 6-25. 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

Figure 6-3 Demand resource metered load compared to PLC and FSL: January 25, 2026



101 The MMU assumes a CBL equivalent to the metered load for hours when a registration did not request an energy settlement.

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 6-27 shows the daily emergency energy payments to load management demand resources for January 25, 2026.[102] 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 6-27 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.[103] 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.[104] FERC approved PJM's proposed changes on June 26, 2026, effective June 27, 2026, ahead of the 2028/2029 BRA.[105]

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.

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

102 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.

103 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>.

104 See PJM. MIC. "*Options & Packages Matrix – Load Management & Price Responsive Demand Event Performance,*" (March 3, 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>.

105 195 FERC ¶ 61,253 (2026).

dispatched registrations reduce their demand.[106] [107] 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.

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.[108] 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 6-28 shows the average hourly HHI for each month and the average hourly HHI for January 1, 2025, through June 30, 2026.[109] The ownership of economic demand response resources was highly concentrated in the first six months of 2025 and 2026.[110] Table 6-28 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 six months of 2026. The HHI for economic demand response in the first six months of 2026 increased by 148, 1.7 percent, from 8631 in the first six months of 2025 to 8779 in the first six months of 2026.

Table 6-28 Average hourly MWh HHI and market concentration in the economic program: January 2025 through June 2026[111]

	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	8849	5.6%		100.0%			100.0%	
Feb	8017	7965	(0.7%)		100.0%			100.0%	
Mar	8510	7960	(6.5%)		100.0%			100.0%	
Apr	8547	9385	9.8%		100.0%			100.0%	
May	8944	8512	(4.8%)		100.0%			100.0%	
Jun	9383	10000	6.6%						
Jul	9142								
Aug	9198								
Sep	9195								
Oct	9400								
Nov	8121								
Dec	7745			100.0%			100.0%		
Total	8969	8526	(4.9%)	100.0%	100.0%		100.0%	0.0%	

106 See PJM OATT, Attachment K, Section 8.5.
107 See PJM, Intra-PJM Tariffs, RAA, Definition of "Firm Service Level".
108 Also known in the PJM Market Rules as the Economic Load Response Program.

109 Load response credits and reductions were downloaded as of July 14, 2026, and may change as a result of continued PJM billing updates.
110 All HHI calculations in this section are at the parent company level.
111 Omitted reduction and credit share values are based on confidentiality rules that require published data to include more than four owners.

Market Performance

Table 6-29 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 June, 2010 through 2026.[112] The average credits per MWh paid increased by $125.33 per MWh, 213.2 percent, from $58.79 per MWh in the first six months of 2025 to $184.11 per MWh in the first six months of 2026. Curtailed energy for the economic program was 100,055 MWh in the first six months of 2026, a decrease of 175,604 MWh, 63.7 percent, as compared to curtailed energy for the economic program in the first six months of 2025. Total credits paid for the economic load response program in the first six months of 2026 were $18,421,569, an increase of $2,216,843, 13.7 percent, compared to the total credits paid for the economic load response program in the first six months of 2025.

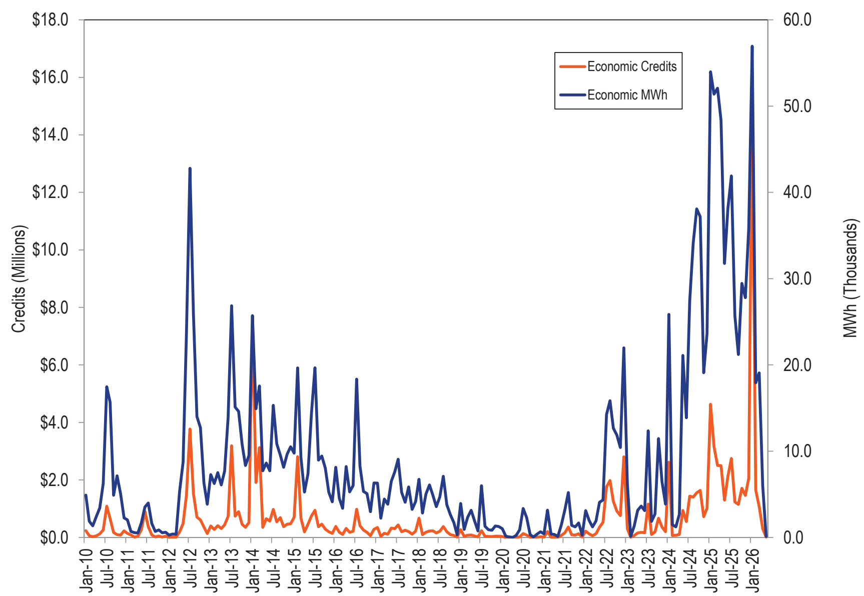
Table 6-29 Credits paid to economic program participants: January through June, 2010 through 2026

(Jan-Jun)	Total MWh	Total Credits	$/MWh
2010	20,225	$761,854	$37.67
2011	9,055	$1,456,324	$160.84
2012	38,692	$2,172,454	$56.15
2013	48,711	$2,559,831	$52.55
2014	82,273	$14,298,502	$173.79
2015	65,653	$5,576,152	$84.93
2016	35,559	$1,381,972	$38.86
2017	30,954	$1,281,762	$41.41
2018	29,155	$1,566,879	$53.74
2019	12,964	$548,988	$42.35
2020	2,342	$57,078	$24.37
2021	5,876	$318,723	$54.24
2022	16,633	$1,416,246	$85.14
2023	17,610	$882,334	$50.10
2024	66,227	$4,355,242	$65.76
2025	275,659	$16,204,726	$58.79
2026	100,055	$18,421,569	$184.11

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.[113] 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.[114] 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 6-4 shows monthly economic demand response credits and MWh, from 2010 through June 30, 2026.

Figure 6-4 Economic program credits and MWh by month: 2010 through June 2026



112 Load response credits were downloaded as of July 14, 2026, and may change as a result of continued PJM billing updates.
113 "PJM. Manual 11: Energy & Ancillary Services Market Operations," § 10.4.5, Rev. 136 (October 1, 2025).
114 *Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 831, 157 FERC ¶ 61,115 (2016) ("Order No. 831").

Table 6-30 shows performance for January through June, 2025 and 2026 in the economic program by control zone. Total reported reductions under the economic program decreased by 175,604 MWh, 63.7 percent, from 275,659 MWh in the first six months of 2025 to 100,055 MWh in the first six months of 2026. Total revenue under the economic program increased by $2.2 million, 13.7 percent, from $16.2 million in the first six months of 2025 to $18.4 million in the first six months of 2026.[115]

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.[116] The zonal allocation is shown in Table 6-30.

Table 6-30 Economic program participation by zone: January through June, 2025 and 2026

	Credits			MWh Reductions			Credits per MWh Reduction		
Zone	2025 (Jan-Jun)	2026 (Jan-Jun)	Percent Change	2025 (Jan-Jun)	2026 (Jan-Jun)	Percent Change	2025 (Jan-Jun)	2026 (Jan-Jun)	Percent Change
AECO	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
AEP	$6,342,943.37	$6,237,136.55	(1.7%)	111,573	53,276	(52.3%)	$56.85	$117.07	105.9%
APS	$592,420.94	$9,245,052.98	1,460.6%	14,142	19,617	38.7%	$41.89	$471.27	1,025.0%
ATSI	$2,797,136.08	$2,330,725.65	(16.7%)	21,554	20,550	(4.7%)	$129.77	$113.42	(12.6%)
BGE	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
COMED	$26,466.37	($2.62)	(100.0%)	764	0	(100.0%)	$34.66	($58.61)	(269.1%)
DAY	($4,695.51)	$823.95	(117.5%)	0	4	NA	NA	$192.50	NA
DEOK	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
DUQ	$6,302,458.42	$420,819.69	(93.3%)	126,508	5,011	(96.0%)	$49.82	$83.98	68.6%
DOM	$62,955.91	$72,929.46	15.8%	254	143	(43.6%)	$247.86	$509.25	105.5%
DPL	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
JCPL	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
METED	$0.00	$13,143.80	NA	0	74	NA	NA	$177.55	NA
OVEC	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
PECO	$19,649.29	$12,730.75	(35.2%)	323	148	(54.3%)	$60.76	$86.19	41.8%
PENELEC	$0.00	$45,933.07	NA	0	771	NA	NA	$59.54	NA
PEPCO	$2,064.47	$2,118.98	2.6%	28	28	0.5%	$73.75	$75.33	2.1%
PPL	$4,322.54	$0.00	NA	22	0	NA	$196.74	NA	NA
PSEG	$59,004.58	$40,156.76	(31.9%)	491	432	(12.1%)	$120.19	$93.03	(22.6%)
REC	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
Total	$16,204,726.47	$18,421,569.04	13.7%	275,659	100,055	(63.7%)	$58.79	$184.11	213.2%

115 Economic demand response reductions that are submitted to PJM for payment but have not received payment are not included in Table 6-42. Payments for Economic demand response reductions are settled monthly.
116 "PJM Manual 28: Operating Agreement Accounting," § 11.2.2, Rev. 104 (March 1, 2026).

Table 6-31 shows average reported MWh reductions and credits by hour for the first six 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 six months of 2025, 60.7 percent of the reported reductions and 60.5 percent of credits occurred in hours ending 0900 EPT to 2100 EPT, and in the first six months of 2026, 53.6 percent of the reported reductions and 52.3 percent of credits occurred in hours ending 0900 EPT to 2100 EPT. The average LMP during load response increased by $89.47 per MWh, 159.0 percent, from $56.25 per MWh in the first six months of 2025 to $145.72 per MWh in the first six months of 2026.

Table 6-31 Hourly frequency distribution of economic program reported MWh reductions and credits: January through June, 2025 and 2026

	MWh Reductions			Program Credits			Average LMP during Load Response		
Hour Ending (EPT)	2025 (Jan-Jun)	2026 (Jan-Jun)	Percent Change	2025 (Jan-Jun)	2026 (Jan-Jun)	Percent Change	2025 (Jan-Jun)	2026 (Jan-Jun)	Percent Change
1 through 6	40,128	21,620	(46%)	$2,225,218	$4,242,984	91%	$49.80	$145.63	192%
7	13,844	5,538	(60%)	$919,457	$1,038,512	13%	$63.61	$164.86	159%
8	14,691	5,498	(63%)	$1,039,228	$1,090,986	5%	$70.74	$173.01	145%
9	12,789	4,707	(63%)	$746,275	$843,536	13%	$52.52	$140.14	167%
10	11,127	3,840	(65%)	$579,404	$633,603	9%	$47.68	$117.99	147%
11	11,312	4,140	(63%)	$603,779	$709,394	17%	$49.72	$127.14	156%
12	11,166	3,866	(65%)	$584,900	$691,502	18%	$47.10	$127.39	170%
13	11,220	3,665	(67%)	$588,288	$618,357	5%	$46.84	$121.72	160%
14	10,933	3,229	(70%)	$588,256	$596,719	1%	$47.06	$121.91	159%
15	10,024	3,270	(67%)	$499,739	$581,226	16%	$47.93	$120.70	152%
16	10,068	3,189	(68%)	$521,186	$581,426	12%	$52.04	$125.81	142%
17	11,534	3,585	(69%)	$634,637	$627,179	(1%)	$54.87	$128.74	135%
18	14,938	4,959	(67%)	$930,984	$882,195	(5%)	$65.45	$141.74	117%
19	16,796	5,010	(70%)	$1,093,858	$962,378	(12%)	$68.20	$155.55	128%
20	17,950	5,277	(71%)	$1,231,226	$1,013,284	(18%)	$73.68	$155.90	112%
21	17,350	4,925	(72%)	$1,193,788	$896,440	(25%)	$69.28	$144.14	108%
22	15,484	4,764	(69%)	$915,958	$894,912	(2%)	$56.90	$146.31	157%
23 through 24	24,305	8,971	(63%)	$1,308,546	$1,516,936	16%	$49.13	$264.28	438%
Total	275,659	100,055	(64%)	$16,204,726	$18,421,569	14%	$56.25	$145.72	164%

Table 6-32 shows the distribution of economic program reported MWh reductions and credits by ranges of real-time zonal load-weighted average LMP in the first six months of 2025 and 2026. In the first six months of 2026, 37.0 percent of reported MWh reductions and 79.2 percent of program credits occurred during hours when the applicable zonal LMP was higher than $175 per MWh.

Table 6-32 Frequency distribution of economic program zonal load-weighted average LMP (By hours): January through June, 2025 and 2026

	MWh Reductions			Program Credits		
LMP	2025 (Jan-Jun)	2026 (Jan-Jun)	Percent Change	2025 (Jan-Jun)	2026 (Jan-Jun)	Percent Change
$0 to $25	371	4	(99%)	$6,659	($147)	(102%)
$25 to $50	156,439	31,950	(80%)	$6,017,730	$1,268,722	(79%)
$50 to $75	70,207	17,182	(76%)	$4,237,026	$1,038,799	(75%)
$75 to $100	22,119	3,134	(86%)	$1,908,672	$214,804	(89%)
$100 to $125	10,784	3,380	(69%)	$1,194,192	$267,537	(78%)
$125 to $150	5,593	3,820	(32%)	$705,417	$466,084	(34%)
$150 to $175	2,830	3,543	25%	$443,965	$576,449	30%
> $175	7,317	37,041	406%	$1,691,066	$14,589,322	763%
Total	275,659	100,055	(64%)	$16,204,726	$18,421,569	14%

Economic Load Response revenues are paid by real-time loads and real-time scheduled exports as an uplift charge. Table 6-33 shows the sum of real-time and day-ahead Economic Load Response charges paid in each zone and paid by exports. In the first five months of 2026, DOM Zone has paid the highest Economic Load Response charges.

Table 6-33 Zonal Economic Load Response charge: January through May, 2026[117]

Zone	January	February	March	April	May	Total
AECO	$162,742	$18,667	$7,854	$2,573	$159	$191,995
AEP	$2,589,033	$276,918	$194,990	$55,898	$1,874	$3,118,713
APS	$996,376	$106,650	$69,430	$18,821	$669	$1,191,946
ATSI	$1,116,548	$118,559	$87,880	$24,938	$893	$1,348,818
BGE	$629,191	$68,398	$45,635	$11,352	$471	$755,048
COMED	$721,302	$89,212	$76,538	$16,846	$488	$904,385
DAY	$326,068	$32,271	$24,961	$7,544	$227	$391,072
DUKE	$498,030	$48,468	$35,539	$11,372	$350	$593,759
DUQ	$212,957	$23,239	$16,026	$4,836	$186	$257,244
DOM	$2,611,733	$286,446	$187,000	$55,992	$1,969	$3,143,140
DPL	$404,295	$45,900	$14,720	$4,911	$289	$470,115
EKPC	$348,404	$33,003	$19,806	$4,918	$175	$406,306
JCPLC	$380,822	$42,307	$20,408	$6,210	$426	$450,173
MEC	$284,322	$30,346	$17,036	$3,603	$223	$335,530
OVEC	$2,122	$231	$165	$45	$1	$2,564
PECO	$722,747	$80,235	$28,568	$10,699	$621	$842,870
PE	$304,591	$32,586	$20,819	$6,043	$216	$364,255
PEPCO	$575,963	$61,981	$40,307	$10,448	$434	$689,133
PPL	$807,233	$85,826	$40,018	$9,912	$559	$943,548
PSEG	$725,637	$80,599	$40,956	$12,759	$756	$860,707
REC	$22,198	$2,454	$1,671	$457	$27	$26,808
Exports	$939,078	$87,414	$82,211	$24,377	$360	$1,133,440
Total	$15,381,392	$1,651,712	$1,072,537	$304,553	$11,374	$18,421,569

117 Load response charges were downloaded as of July 14, 2026, and may change as a result of continued PJM billing updates.

Table 6-34 shows the total zonal Economic Load Response charge per GWh of real-time load and exports in the first five months of 2026.[118]

Table 6-34 Zonal economic load response charge per GWh of load and exports: January through May, 2026

Zone	January	February	March	April	May	Zonal Average
AECO	$0.190	$0.024	$0.011	$0.004	$0.000	$0.046
AEP	$0.187	$0.023	$0.017	$0.005	$0.000	$0.047
APS	$0.195	$0.024	$0.018	$0.005	$0.000	$0.049
ATSI	$0.179	$0.022	$0.017	$0.005	$0.000	$0.045
BGE	$0.204	$0.025	$0.020	$0.006	$0.000	$0.051
COMED	$0.084	$0.013	$0.011	$0.003	$0.000	$0.022
DAY	$0.193	$0.023	$0.018	$0.006	$0.000	$0.048
DUKE	$0.198	$0.023	$0.018	$0.006	$0.000	$0.049
DUQ	$0.180	$0.023	$0.016	$0.005	$0.000	$0.045
DOM	$0.200	$0.025	$0.018	$0.006	$0.000	$0.050
DPL	$0.208	$0.026	$0.010	$0.004	$0.000	$0.050
EKPC	$0.213	$0.025	$0.019	$0.005	$0.000	$0.052
JCPLC	$0.189	$0.023	$0.013	$0.004	$0.000	$0.046
MEC	$0.189	$0.023	$0.014	$0.003	$0.000	$0.046
OVEC	$0.175	$0.021	$0.017	$0.005	$0.000	$0.044
PECO	$0.192	$0.024	$0.010	$0.004	$0.000	$0.046
PE	$0.190	$0.023	$0.015	$0.005	$0.000	$0.047
PEPCO	$0.207	$0.025	$0.019	$0.005	$0.000	$0.051
PPL	$0.193	$0.023	$0.012	$0.003	$0.000	$0.046
PSEG	$0.189	$0.023	$0.013	$0.004	$0.000	$0.046
REC	$0.185	$0.023	$0.016	$0.005	$0.000	$0.046
Exports	$0.182	$0.023	$0.022	$0.008	$0.000	$0.047
Monthly Average	$0.187	$0.023	$0.016	$0.005	$0.000	$0.046

Table 6-35 shows the monthly day-ahead and real-time Economic Load Response charges for the first six months of 2025 and 2026. The day-ahead Economic Load Response charges increased by $2.4 million, 14.7 percent, from $16.0 million in the first six months of 2025 to $18.4 million in the first six months of 2026. The real-time Economic Load Response charges decreased $0.14 million, 84.6 percent, from $0.16 million in the first six months of 2025 to $0.02 million in the first six months of 2026.[119]

Table 6-35 Monthly day-ahead and real-time economic load response charge: January 2025 through June 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	$15,360,176.94	233.4%	$24,927.49	$21,215.43	(14.9%)
Feb	$3,044,896.16	$1,650,544.56	(45.8%)	$106,924.73	$1,167.47	(98.9%)
Mar	$2,490,134.89	$1,071,937	(57.0%)	$12,265.71	$600	(95.1%)
Apr	$2,490,668.50	$303,569	(87.8%)	$7,972	$984	(87.7%)
May	$1,289,551.02	$10,517	(99.2%)	$6,550	$858	(86.9%)
Jun	$2,121,483.73	$0	(100.0%)	$2,845	$0	(100.0%)
Jul	$2,739,664.11					
Aug	$1,233,124.11					
Sep	$1,145,099.85					
Oct	$1,708,020.71					
Nov	$1,461,705.46					
Dec	$2,054,421.06					
Total (Jan-Jun)	$16,043,242.18	$18,396,744.10	14.7%	$161,484.28	$24,824.94	(84.6%)

118 Load response charges were downloaded as of July 14, 2026, and may change as a result of continued PJM billing updates.

119 Load response charges were downloaded as of July 14, 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 6-36 shows registered sites and MW for the last day of each month for the period January 1, 2022, through June 30, 2026. Registration is a prerequisite for CSPs to participate in the economic program. Average monthly registrations decreased by 21, 3.5 percent, from 579 in the first six months of 2025 to 558 in the first six months of 2026. Average monthly registered MW decreased by 74 MW, 2.4 percent, from 3,123 MW in the first six months of 2025 to 3,049 MW in the first six 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 165 economic registrations and 171 capacity registrations in the emergency program that share the same location IDs in both programs. There are 1,614.6 nominated economic MW, 53.0 percent of all economic MW and 1461.1 nominated capacity MW, 20.1 percent of all nominated capacity MW in the emergency program that share the same location IDs in both programs.

Table 6-36 Economic program registrations on the last day of the month: 2022 through June 2026[120]

	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	575	3,063
Feb	323	2,256	354	2,870	472	3,299	576	3,013	574	3,125
Mar	330	2,377	361	2,930	476	3,244	587	3,166	565	3,033
Apr	330	2,382	373	2,932	481	3,207	580	3,157	571	3,133
May	326	2,377	378	3,006	487	3,230	585	3,275	547	3,088
Jun	315	2,323	396	2,929	501	2,942	581	3,147	517	2,851
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	558	3,049

120 Data for years 2010 through 2017 are available in the *2017 Annual State of the Market Report for PJM.*

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 6-37 shows the sum of maximum economic MW dispatched by registration each month from January 1, 2014, through June 30, 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 29.5 MW, 9.7 percent, in the first six months of 2026 compared to the first six months of 2025.[121]

Table 6-37 Sum of maximum MW reported reductions for all registrations per month: 2014 through June 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	447
Feb	307	336	128	83	70	58	11	86	34	18	102	409	417
Mar	369	198	120	111	71	38	12	20	30	53	102	271	295
Apr	146	143	118	54	71	41	3	22	43	70	84	245	142
May	151	161	131	169	70	22	12	9	53	141	247	152	263
Jun	483	833	121	240	105	26	38	125	110	96	213	342	84
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	563

Table 6-38 shows total settlements submitted for 2014 through 2026. A settlement is counted for every day on which a registration is dispatched in the economic program.

Table 6-38 Settlements submitted in the economic program: January through June, 2014 through 2026

(Jan-Jun)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Number of Settlements	1,806	1,091	652	800	737	426	193	289	849	243	644	1,757	1,210

Table 6-39 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 9, 20.9 percent, from 43 in the first six months of 2025 to 52 in the first six months of 2026. All participants must be registered through a CSP.

Table 6-39 Participants and CSPs submitting settlements in the economic program by year: January through June, 2014 through 2026

(Jan-Jun)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Active CSPs	17	12	6	8	11	9	8	10	8	5	5	4	5
Active Participants	144	68	20	42	30	24	17	30	23	12	28	43	52

121 Maximum MW reductions were downloaded as of July 14, 2026, and may change as a result of continued PJM billing updates.

Issues

FERC Order No. 831 requires that each RTO/ISO market monitoring unit verify all energy offers above $1,000 per MWh.[122] 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."[123] 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 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.[124] 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.[125]

122 157 FERC ¶ 61,115 at P 139 (2016).
123 *Id.* at 8.
124 "PJM Manual 11: Energy & Ancillary Services Market Operations," §10.3.1, Rev. 136 (October 1, 2025)
125 "PJM Manual 11: Energy & Ancillary Services Market Operations," §10.3.4, Rev. 136 (October 1, 2025)

Table 6-40 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 June 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 six months of 2026, the NBT threshold price did not exceed the lowest historical test result of $34.07 per MWh.

Table 6-40 Net benefits test threshold prices: August 2010 through June 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	$24.05
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	$21.79
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	$21.52
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	$25.12

Table 6-41 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.[126] In the first six months of 2026, the highest zonal LMP in PJM was higher than the NBT threshold price 4,226 hours out of 4,343 hours, or 97.3 percent of all hours. Reductions occurred in 3,037 hours, 71.9 percent, of those 4,226 hours in the first six 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 June 30, 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 six months of 2025, and none of the hours in which LMP was below the NBT threshold price in the first six months of 2026.

Table 6-41 Hours with price higher than NBT and economic load response occurrences in those hours: January 2025 through June 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%	89.9%	(5.7%)
Mar	743	743	742	742	0.0%	97.7%	91.6%	(6.1%)
Apr	720	720	662	714	7.9%	94.7%	82.6%	(12.1%)
May	744	744	580	733	26.4%	82.4%	78.7%	(3.7%)
Jun	720	720	685	708	3.4%	77.2%	3.4%	(73.8%)
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	4,343	8,307	4,226	(49.1%)	89.8%	71.9%	(18.0%)

126 The MWh for demand resources were downloaded as of July 14, 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.[127] See the *2025 Annual State of the Market Report for PJM* for detailed information on the EE program and its impacts.

Peak Shaving Adjustment

A Peak Shaving Adjustment (PSA) plan 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.[128] 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.[129] 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

127 See 189 FERC ¶ 61,095, *reh'g denied*, 190 FERC ¶ 62,005 (2025).
128 See "Peak Shaving Adjustment Proposal," Docket No. ER19-511-000 (December 7, 2018).
129 "PJM Manual 19: Load Forecasting and Analysis," Attachment D, Rev. 39 (June 30, 2026).

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.[130] 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.[131] 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 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.

On June 2, 2026, Google LLC ("Google") and Voltus, Inc. ("Voltus") announced that they signed a three year agreement to aggregate up to 100 MW of new DER capacity each year into a "Google-funded VPP in PJM" as part of a Bring Your Own New Generation ("BYONG") framework for large load additions.[132] The structure of the Google and Voltus' DER aggregation is not yet clear. However, this agreement shows that DER Aggregation Resources may play a significant role in the PJM market, as data centers try to find new capacity. This potential role makes it even more critical that DERs should be held to the same standards of performance that apply to generation resources.

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

130 See 172 FERC ¶ 61,247 at PP 6–7.

131 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>.

132 *See Voltus Inc.* Voltus and Google to Deliver Grid Capacity and Local Economic Benefits Through Bring Your Own Capacity Agreement (June 2, 2026) <*https://www.voltus.co/press/voltus-google-bring-your-own-capacity-pjm*>; *See also Google LLC.* We've signed a first-of-its-kind agreement with Voltus to create a smart capacity solution for the grid. (June 2, 2026) <*https://blog.google/company-news/outreach-and-initiatives/sustainability/voltus-agreement/*> .

market. Aggregation behind a single node is feasible, is consistent with the nodal market principle, and will encourage competition. The current DER Aggregation Participation Model allows multinodal aggregation for small resources that satisfy defined 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 will 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 does not permit multinodal aggregation.

The current DER Aggregation Participation Model does not include 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 then 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 will 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 current 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.[133] 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 violate the terms of PJM's tariff and that such actions can be monitored and addressed through existing mechanisms such as Attachment M.[134] However, the 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 retail resource at 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. In seven of the 13 states in PJM and Washington DC, retail customers on a net metering tariff with their distribution utility pay the retail rate when consuming and are paid the full retail rate when selling energy.[135] That full retail rate compensation

133 182 FERC ¶ 61,143 at P 334.
134 See 188 FERC ¶ 61,076 at P 169.
135 *See S&P Global*, PJM Solar and Battery Forecast 2025 at 13, presented at Load Analysis Subcommittee on October 1, 2025, <*https://www.pjm.com/-/media/DotCom/committees-groups/subcommittees/las/2025/20251028/20251028-reference---spglobal---pjm-dg-solar-battery-forecast.pdf*>. The seven states that compensate NEM resources at the full retail rate are Delaware, Maryland, Pennsylvania, West Virginia, Illinois, Michigan and Virginia. Two states are transitioning from the full retail rate compensation to less than full retail rate compensation: Indiana and North Carolina.

includes credits for energy, capacity and ancillary services charges. These resources receive double compensation if they participate in the PJM energy, capacity or ancillary services markets with injections, because they already receive full compensation for their output through the retail rate arrangement.

However, according to PJM's interpretation, as no net metering resources in the PJM footprint provide ancillary services, like reserves or regulation, as part of a retail program, all net metering resources in its territory are eligible to participate in its ancillary services markets under the DER Aggregation Participation Model.[136] From PJM's perspective, this means all net metering resources are eligible to participate in its ancillary services market.[137] 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 as long as it does not provide the same service. 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. Double payment is double counting. The 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 filing at FERC proposing to create a new participation model called Economic Load Response Regulation Only Participants.[138] 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 comments in the docket.[139] [140] FERC issued a deficiency letter to PJM on February 13, 2026.[141] FERC approved the proposal on May 5, 2026.[142]

Behind The Meter Generation

Behind the meter generation ("BTMG") refers to DERs that are co-located with retail load behind a customer meter. These generators may participate in wholesale or in retail markets. Retail BTMG participates only in retail, reducing retail load and retail load charges. Non-Retail BTMG ("NRBTMG") is used by EDCs, municipalities or co-operatives to reduce their wholesale load and wholesale load charges. NRBTMG can be located behind the meter with retail load or located in front of the meter but still on the distribution system. NRBTMG has a PJM system wide cap of 3,000 MW.[143] If a BTMG

136 See Order No. 2222 Compliance Filing of PJM Interconnection, L.L.C., Docket No. ER22-962 (February 1, 2022) at 41.
137 FERC Docket No. ER22-962-005 at 15.
138 PJM Interconnection, L.L.C., Economic Load Response Regulation Only Participants, Docket No. ER26-846-000, (December 19, 2025).

139 Monitoring Analytics, L.L.C., Comments of the Independent Market Monitor for PJM Interconnection, L.L.C., Docket No. ER26-846 (January 9, 2026).
140 Monitoring Analytics, L.L.C., Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, ER26-846 (February 11, 2026).
141 FERC Deficiency Letter, Docket No. ER26-846 (February 13, 2026).
142 195 FERC ¶ 61,090 (May 5, 2026).
143 *See* BTMG Business rules, PJM Manual 14D – Appendix A.

wants to participate in PJM but not as a NRBTMG, it may participate as a generation resource (with injection capability) after going through the PJM interconnection process, or participate as DR (with load reduction) under the DR or the DER aggregation model.

FERC accepted the PJM proposal to set the materiality threshold for BTMG at 50 MW, although FERC directed PJM to change the proposal to permit "Network Customers to net from their Network Load up to 50 MW of load served by using BTMG at a single electrical location" instead of the capacity nameplate limit of 50 MW.[144] This threshold would not apply to existing BTMG with a contractual arrangement that was in effect as of December 18, 2025.

144 *See* 195 FERC ¶ 61,209 at PP 207-220.