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 $369.9 million, 240.6 percent, from $153.7 million in 2024 to $523.6 million in 2025, primarily due to increases in capacity market revenue. Emergency demand response revenue accounted for 87.9 percent of all demand response revenue, economic demand response for 4.6 percent, demand response in the synchronized reserve market for 3.7 percent and demand response in the regulation market for 3.8 percent.

  Total emergency demand response revenue increased by $343.6 million, 294.6 percent, from $116.6 million in 2024 to $460.3 million in 2025.[2] This increase was primarily a result of higher capacity market prices and capacity market revenue.

  Economic demand response revenue increased by $12.0 million, 98.8 percent, from $12.1 million in 2024 to $24.1 million in 2025.[3] Demand response revenue in the synchronized reserve market increased by $8.4 million, 76.3 percent, from $11.0 million in 2024 to $19.4 million in 2025. Demand response revenue in the regulation market increased by $5.9 million, 42.2 percent, from $14.0 million in 2024 to $19.8 million in 2025.

- **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 2024 and 2025. The HHI for economic demand response resource reductions increased by 254 points from 8684 in 2024 to 8938 in 2025.

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

- **Limited Locational Dispatch of Demand Resources.** With full implementation of the Capacity Performance rules in the capacity market in the 2020/2021 Delivery Year, PJM should be able to individually dispatch any capacity performance resource, including demand resources. PJM cannot dispatch demand resources by node with the current rules because demand resources are not registered to a node. In addition, aggregation rules allow a demand resource that incorporates many small End Use Customers to span an entire zone, which is inconsistent with nodal dispatch.

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 January 13, 2026, and may change as a result of continued PJM billing updates.
3 Economic credits are synonymous with revenue received for reductions under the economic load response program.
4 "PJM Manual 28: Operating Agreement Accounting," § 11.2.2, Rev. 104 (March 1, 2026).

- **Energy Efficiency.** Energy efficiency payments have been eliminated from PJM markets effective June 1, 2026. Energy efficiency resources are not capacity resources in PJM and do not clear in the capacity market. The total MW of energy efficiency resources paid decreased by 80.6 percent, from 7,716.0 MW in the 2024/2025 Delivery Year to 1,493.2 MW in the 2025/2026 Delivery Year. In the 2025/2026 Delivery Year, payments to EE are $148 million.
- **Energy Efficiency Payments are a Subsidy and Uplift.** Payments from the buyers of capacity to energy efficiency providers are a subsidy and uplift. Energy efficiency is not a capacity resource and does not contribute to reliability.
- **Energy Efficiency Market Concentration.** The HHI for energy efficiency on an aggregate market basis shows that ownership is highly concentrated. The four largest companies own 90 percent or more of all paid Energy Efficiency MW. The HHI for Energy Efficiency resources also shows that ownership is highly concentrated for the 2025/2026 Delivery Year, with an HHI value of 2804. In the 2025/2026 Delivery Year, the four largest companies own 96.0 percent of all paid Energy Efficiency MW.

Recommendations

- The MMU recommends that PJM report the response of emergency demand response resources to dispatch by PJM as the actual change in load rather than simply the difference between the amount of capacity purchased by the customer and the actual metered load. The performance metric should be (CBL – Metered load)/(CBL – FSL). The current approach significantly overstates the expected response to PJM dispatch. (Priority: High. First reported 2023. Status: Not adopted.)
- The MMU recommends that FSL registrations be required to reduce to their FSL and GLD registrations be required to reduce by their committed amount in every event hour. (Priority: High. New recommendation. 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.)

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

- The MMU recommends that, if emergency demand response resources remain in the capacity market, a daily energy market must offer requirement apply to emergency demand response resources, comparable to the rule applicable to generation capacity resources.[6] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that emergency demand response resources be required to provide their nodal location, comparable to generation resources. (Priority: High. First reported 2011. Status: Not adopted.)
- The MMU recommends that PJM require nodal dispatch of emergency demand response resources with no advance notice required or, if nodal location is not required, subzonal dispatch of demand resources with no advance notice required. The MMU recommends that, if PJM continues to use subzones for any purpose, PJM clearly define the role of subzones in the dispatch of demand response. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not remove any defined subzones and maintain a public record of all created and removed subzones. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM eliminate the measurement of compliance across zones within a compliance aggregation area (CAA). The multiple zone approach is less locational than the zonal and subzonal approach and creates larger mismatches between the locational need for the resources and the actual response. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that measurement and verification methods for all demand resources be modified to reflect compliance more accurately. (Priority: Medium. First reported 2009. Status: Not adopted.)
- 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.)

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

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

- The MMU recommends that there be only one demand response product in the capacity market, with an obligation to respond when called for any hour of the delivery year. (Priority: High. First reported 2011. Status: Partially adopted.[8])
- The MMU recommends that all demand resources register as Pre-Emergency and that the Emergency Program be eliminated. (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends that the lead times for emergency demand response resources be shortened to 30 minutes with a one hour minimum dispatch for all resources. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends setting the baseline for measuring capacity compliance under winter compliance at the customers' PLC, similar to GLD, to avoid double counting. (Priority: High. First reported 2010. Status: Partially adopted.)
- The MMU recommends the Relative Root Mean Squared Test be required for all demand resources with a CBL. (Priority: Low. First reported 2017. Status: Partially adopted.)
- The MMU recommends that 30 minute pre-emergency and emergency demand response be considered to be 30 minute reserves. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that energy efficiency resources (EE) not be included in the capacity market mechanism and that PJM should ensure that the impact of EE measures on the load forecast is incorporated immediately. (Priority: Medium. First reported 2018. Status: Adopted 2024.)[9] [10]
- The MMU recommends that demand reductions based entirely on behind the meter generation be capped at the lower of economic maximum or actual generation output. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that DER aggregations that clear in a capacity auction not be permitted to change status from homogeneous demand response to any other status for any additional auctions for the same delivery year, or for the delivery year. (Priority: High. First reported Q3, 2025. Status: Not adopted.)
- The MMU recommends that EDCs not be allowed to participate in markets as DER aggregators in addition to their EDC role. (Priority: High. First reported 2021. Status: Not adopted.)
- The MMU recommends that PJM include a 5.0 MW maximum size cap on DER aggregations. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that PJM use a nodal approach for DER participation in PJM markets that excludes multinodal aggregation. (Priority: Medium. First reported 2022. Status: Partially adopted.)
- The MMU recommends that the Commission require PJM to include in OATT Attachment M the explicit statement that the Market Monitor's role includes the right to collect information from EDCs and DERA related to actions taken on the distribution system related to DERs. (Priority: Medium. First reported 2023. Status: Not adopted.)
- The MMU recommends that net metering resources be prohibited from participating in wholesale ancillary services markets if they are compensated for the service at the retail level. (Priority: Medium. First reported Q2, 2025. Status: Not adopted.)
- The MMU recommends that PJM revise the requirements for reporting expected real time energy load reductions by CSPs to PJM to improve the 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

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

all CP resources. (Priority: Medium. First reported Q3, 2025. Status: Not adopted.)

Conclusion

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

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

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

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

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

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

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

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

In order to be a substitute for generation, compliance by demand resources with PJM dispatch instructions should include both increases and decreases in load. Compliance of demand resources for capacity purposes during a Performance Assessment Event is measured relative to either Peak Load Contribution or Winter Peak Load, which are static values. If a demand resource's metered load increases above these reference values during a PAI, the current method applied by PJM simply ignores increases in load and thus artificially overstates compliance.[11]

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

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

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

The MMU peak shaving proposal at the Summer-Only Demand Response Senior Task Force (SODRSTF) is an example of how to create a demand side product that is on the demand side of the market and not on the supply side.[12] The MMU proposal was based on the BGE load forecasting program and the Pennsylvania Act 129 Utility Program.[13] [14] Under the MMU proposal, participating load would inform PJM prior to an RPM auction of the MW participating, the months and hours of participation and the temperature humidity index (THI) threshold at which load would be reduced. PJM would reduce the load forecast used in the RPM auction based on the designated reductions. Load would agree to curtail demand to at or below a defined FSL, less than the customer PLC, when the THI exceeds a defined level or load exceeds a specified threshold. By relying on metered load and the PLC, load can reduce its demand for capacity and that reduction can be verified without complicated and inaccurate metrics to estimate load reductions. Under PJM's weakened version of the program, performance is measured under the current economic demand response CBL rules which means relying on load estimates rather than actual metered

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).

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

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

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

load.[15] PJM's proposal includes only a THI curtailment trigger and not an overall load curtailment trigger.

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

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

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

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

This approach would work under the CP design in the capacity market. This approach is entirely consistent with the Supreme Court decision in EPSA as it does not depend on whether FERC has jurisdiction over the demand side.[16] This approach will allow FERC to more fully realize its overriding policy objective to create competitive and efficient wholesale energy markets. The decision of the Supreme Court addressed jurisdictional issues and did not address the merits of FERC's approach. The Supreme Court's decision has removed the uncertainty surrounding the jurisdictional issues and created the opportunity for FERC to revisit its approach to demand side.

Any discussion of demand resource performance during a PAI must recognize the significant problems with the definition of performance for demand resources. As defined by PJM rules, performance, contrary to intuition, does not mean actually reducing load in response to a PJM request for demand resources. Performance means only that, on a net portfolio basis, the amount of capacity paid for in the capacity market (PLC) minus actual metered load is equal to the amount of demand side capacity sold in the capacity market (ICAP). If a demand resource location was already at a reduced load level when PJM called a PAI, the demand resource would be deemed to have performed if the PLC less the metered load level was equal to the ICAP sold in the capacity market. The standard reporting of demand side response is therefore misleading because it includes loads that were already lower for any reason as a response. That is exactly what happened during Elliott. In addition, PRD is not required to respond if the LMP is less than the PRD strike price. This flawed rule meant that PRD did not fully respond during Winter Storm Elliott because PRD offered at the maximum price of $1,849 per MWh.

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

16 577 U.S. 260 (2016).

PJM Demand Response Programs

All PJM demand response programs can be grouped into economic demand response (energy market demand resources), emergency demand response, pre-emergency demand response and price responsive demand (PRD) (capacity market demand resources), synchronized reserves and regulation.[17] Table 6-1 provides an overview of the key features of PJM demand response programs.

Based on FERC Order No. 719 PJM implemented rules that require PJM to verify with EDCs that no law or regulation of a RERRA prohibits End Use Customers' participation.[18] [19]

Table 6-1 Overview of demand response programs

	Emergency and Pre-Emergency Demand Response Program			Economic Demand Response Program	Price Responsive Demand
	Capacity Market Demand Response			Economic Demand Response	
Product Types	Capacity Performance, Summer-Period Capacity Performance OATT Attachment DD § 5.5A	Capacity Performance,Summer-Period Capacity Performance OATT Attachmend DD § 5.5A		OATT Attachment K § 1.5A	
Market	Capacity Only OATT Attachment K § 8.1	Full Program Option (Capacity and Energy) OATT Attachemnt K § 8.1	Energy Only OATT Attachemnt K § 8.1	Energy Only	Capacity Only
Capacity Market	DR cleared in RPM	DR cleared in RPM	Not included in RPM	Not included in RPM	PRD cleared in RPM
Dispatch Requirement	Mandatory Curtailment	Mandatory Curtailment	Voluntary Curtailment	Dispatched Curtailment	Price Threshold
Capacity Payments	Capacity payments based on RPM clearing price	Capacity payments based on RPM clearing price	NA	NA	LSE PRD Credit RAA Schedule 6.1.G
Capacity Measurement and Verification	Firm Service Level Guaranteed Load Drop	Firm Service Level Guaranteed Load Drop	NA	NA	Firm Service Level
CBL	NA	Yes, as described OATT Attachment K § 3.3A	Yes, as described OATT Attachment K § 3.3A	Yes, as described OATT Attachment K § 3.3A	NA
Energy Payments	No energy payment	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment during PJM declared Emergency Event mandatory curtailments.	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment only for voluntary curtailments.	Energy payment based on full LMP. Energy payment for hours of dispatched curtailment. OATT Attachment K § 3.3A	NA
Penalties	Non-Performance Assessment OATT Attachment DD § 10A RAA Schedule 6.K Test compliance penalties OATT Attachment DD § 11A	Non-Performance Assessment OATT Attachment DD § 10A RAA Schedule 6.K Test compliance penalties OATT Attachment DD § 11A	NA	NA	Non-Performance Assessment RAA Schedule 6.1.G Test compliance penalties RAA Schedule 6.1.L
Associate Manuals	Manual 18	Manual 11 Manual 18	Manual 11 Manual 18	Manual 11	Manual 18

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

18 *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 154 (2008), *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292, *order on reh'g*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

19 The evidence supplied by LDCs must take the form of an order, resolution or ordinance of the RERRA, an opinion of the RERRA's legal counsel attesting to existence of an order, resolution, or ordinance, or an opinion of the state attorney general on behalf of the RERRA attesting to existence of an order, resolution or ordinance.

Non-PJM Demand Response Programs

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

PJM Demand Response Programs

Figure 1 shows all revenue from PJM demand response programs by market for each year, 2008 through September 2025. 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 2025, total demand response revenue increased by $369.9 million, 240.6 percent, from $153.7 million in 2024 to $523.6 million in 2025, primarily due to increases in capacity market prices and revenue. Total emergency demand response revenue increased by $343.6 million, 294.6 percent, from $116.6 million in 2024 to $460.3 million in 2025. This increase was primarily a result of higher capacity market prices and capacity market revenue.[22] In 2025, emergency demand response revenue, which includes capacity and emergency energy revenue, accounted for 87.9 percent of all revenue received by demand response providers, the economic program for 4.6 percent, synchronized reserve for 3.7 percent and the regulation market for 3.8 percent.

Economic demand response revenue increased by $12.0 million, 98.8 percent, from $12.1 million in 2024 to $24.1 million in 2025.[23] Demand response revenue in the synchronized reserve market increased by $8.4 million, 76.3 percent, from $11.0 million in 2024 to $19.4 million in 2025. Demand response revenue in the regulation market increased by $5.9 million, 42.2 percent, from $14.0 million in 2024 to $19.8 million in 2025.

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

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

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

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

Figure 6-1 Demand response revenue by market: 2008 to 2025

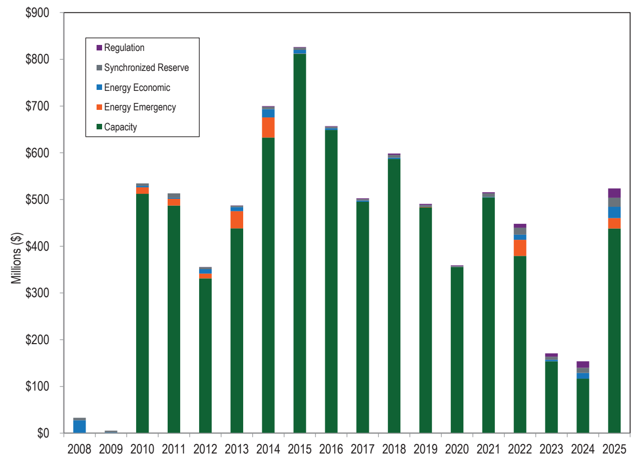


Table 6-2 shows the monthly demand response cleared volumes and revenues in the synchronized reserve market.

Table 6-2 Demand response synchronized reserve market MWh and revenue: 2024 and 2025

	MWh			Revenue		
Month	2024	2025	Percent Change	2024	2025	Percent Change
Jan	299,469	188,234	(37.1%)	$719,294.50	$528,551.11	(26.5%)
Feb	312,394	192,247	(38.5%)	$544,082.82	$569,852.48	4.7%
Mar	340,047	339,478	(0.2%)	$1,370,683.73	$2,228,065.08	62.6%
Apr	213,888	226,206	5.8%	$877,390.11	$2,013,303.75	129.5%
May	344,696	404,918	17.5%	$1,577,366.27	$1,673,752.10	6.1%
Jun	210,675	415,556	97.2%	$606,492.40	$2,119,535.48	249.5%
Jul	218,111	393,494	80.4%	$811,495.66	$2,362,323.88	191.1%
Aug	277,126	396,407	43.0%	$776,668.66	$1,146,787.69	47.7%
Sep	302,202	393,198	30.1%	$1,059,614.05	$1,600,803.08	51.1%
Oct	287,022	440,636	53.5%	$1,345,131.42	$2,196,860.17	63.3%
Nov	326,015	450,039	38.0%	$803,292.28	$1,620,857.94	101.8%
Dec	302,315	359,957	19.1%	$522,407.37	$1,355,664.28	159.5%
Total (Jan-Dec)	3,433,960	4,200,370	22.3%	$11,013,919.27	$19,416,357.04	76.3%

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: 2024 and 2025

	MWh			Revenue		
Month	2024	2025	Percent Change	2024	2025	Percent Change
Jan	35,779	36,051	0.8%	$1,423,346.65	$2,201,687.59	54.7%
Feb	35,638	33,520	(5.9%)	$793,854.86	$1,435,956.43	80.9%
Mar	36,480	36,455	(0.1%)	$955,548.18	$1,608,850.18	68.4%
Apr	34,964	34,413	(1.6%)	$829,068.59	$1,107,759.21	33.6%
May	35,437	35,331	(0.3%)	$1,386,406.04	$1,148,378.85	(17.2%)
Jun	32,568	34,489	5.9%	$909,381.10	$1,643,056.35	80.7%
Jul	35,252	30,291	(14.1%)	$1,458,331.13	$1,280,184.34	(12.2%)
Aug	35,647	31,657	(11.2%)	$1,076,920.47	$1,067,364.48	(0.9%)
Sep	35,178	29,092	(17.3%)	$1,261,594.39	$1,278,466.14	1.3%
Oct	34,748	28,089	(19.2%)	$1,312,029.32	$3,200,499.94	143.9%
Nov	36,400	28,716	(21.1%)	$1,113,489.47	$1,548,962.74	39.1%
Dec	38,657	37,632	(2.7%)	$1,433,963.82	$2,317,751.60	61.6%
Total (Jan-Dec)	426,748	395,737	(7.3%)	$13,953,934.02	$19,838,917.85	42.2%

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. A 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]

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

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: 2025

Method	MW	Percent
Generator	139.1	5.7%
HVAC	78.9	3.2%
Lighting	165.3	6.8%
Refrigeration	16.0	0.7%
Manufacturing	1,362.0	55.7%
Water Heaters	0.0	0.0%
Batteries	14.1	0.6%
Plug Load	1.6	0.1%
Computing	670.3	27.4%
Total	2,447.2	100.0%

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

Table 6-5 Demand response regulation load reduction methods: 2025

Method	MW	Percent
Water Heaters	143.8	63.1%
Batteries	84.2	36.9%
Total	228.0	100.0%

Emergency and Pre-Emergency Demand Response Programs

Pre-Emergency is the default status for capacity market demand response resources. Emergency status is only for resources that use behind the meter generation and that generation has environmental restrictions that limit the resource's ability to operate only in emergency conditions.[25] All demand resources must register as pre-emergency unless the participant qualifies for emergency. PJM also uses the term Load Management Program to refer to the emergency and pre-emergency demand response resources.

Capacity demand response resources may be dispatched both as part of, and absent, a PAI. While demand resources dispatched during a PAI continue to be subject to Non-Performance Assessment charges, demand resources dispatched outside of a PAI are not subject to any event specific penalties.[26] If a demand resource is dispatched only outside of Performance Assessment Events for the delivery year, its performance for the delivery year is determined based on the better of actual performance or a test.[27] There are no penalties or consequences for demand response nonperformance.

For example, if a demand resource is called upon five times during the delivery year only outside of Performance Assessment events and fails to perform each time, its delivery year performance will be based only on a test. If the performance under the test is better than the actual performance, no penalties would be levied even though the resource failed to perform each time it was needed.

The MMU recommends that PJM define when operators can and should call on demand resources, given that a call on demand resources no longer triggers a PAI. The MMU recommends that PJM revise the performance requirements for demand resources to include an event specific measurement for dispatch occurring outside of Performance Assessment Events and penalties for nonperformance.

In all demand response programs, CSPs are companies that sign up end use retail customers that have the ability to reduce load. CSPs satisfy cleared RPM commitments by registering end use retail customers as Nominated MW.[28] After a demand response event occurs, PJM compensates CSPs for their participants' load reductions and CSPs in turn compensate their participants. Only CSPs are eligible to participate in the PJM demand response programs, but a participant can register as a PJM special member and become a CSP without any additional cost.

All emergency or pre-emergency demand resources must be registered as annual capacity resources. Summer period demand response resources are allowed to aggregate with winter period capacity resources to fulfill the annual requirement.[29]

The rules applied to demand resources (DR) in the current market design do not treat demand resources in a manner comparable to generation capacity resources, even though demand resources are sold in the same capacity market, are treated as a substitute for other

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.
28 See RAA Schedule 6. Since 2010, the PJM tariff definition of "End User Customer" limits the scope of the term to mean only PJM Members. Letter Order, Docket No. ER11-1909-000 (December 20, 2010). Recently, PJM has asserted that the reference in RAA Schedule 6 § L.1 and OATT Attachment DD-1 § L.1 to the defined term, "End Use Customer," was a mistake, and proposed to discontinue use of the defined term in the February 8, 2024, meeting of the PJM Governing Document Enhancement and Clarification Subcommittee (GDECS). The proposed change would remove the current requirement in the filed tariff that End Use Customers be PJM Members. The proposed change is substantive and not a correction of a typographical error.
29 Summer period demand response must be available for June through October and the following May between 10:00AM and 10:00PM EPT. *See* PJM OATT RAA Article 1.

capacity resources and displace other capacity resources in RPM auctions. PJM will not measure compliance for DR, and the resources will not face penalties, in a PAI unless the product type and lead time type are dispatched by PJM. PJM does not dispatch DR nodally like other capacity resources. DR can only be dispatched on a zonal or subzonal basis. PJM will not measure compliance for DR, and the resources will not face penalties, in a PAI if the area dispatched is not a defined subzone or control zone. With the dispatch of DR no longer triggering a PAI, demand resources dispatched outside of a PAI are no longer subject to any event specific penalties or consequences for nonperformance.

Demand resources are not subject to the same rules as other capacity resources related to the definition of response. Increases in load are ignored when calculating the response of DR to a PJM dispatch.

Demand resources are not required to meet the same must offer requirements as other capacity resources. All other capacity resources must offer in the capacity market and all other capacity resources must offer their ICAP MW daily in the day-ahead energy market.

The MMU has made recommendations that would provide a capacity market supply side and a demand side option and that would result in treating demand resources in a manner comparable to other capacity and energy resources and in a way that would ensure that the demand side contribution to reliability is accurately measured.

Market Structure

The HHI for demand resources shows that ownership was highly concentrated for the 2024/2025 Delivery Year, with an HHI value of 2387. In the 2024/2025 Delivery Year, the four largest companies contributed 88.5 percent of all committed demand response UCAP MW. The HHI for demand resources shows that ownership is highly concentrated for the 2025/2026 Delivery Year, with an HHI value of 2517. In the 2025/2026 Delivery Year, the four largest companies own 86.7 percent of all committed demand response UCAP MW.

Table 6-6 shows the HHI value for committed Demand Response UCAP MW and the market share of the four largest suppliers by delivery year.

Table 6-6 Demand Response HHI: 2019/2020 through 2025/2026

Delivery Year	HHI	Structure	Top 4 Market Share
2019/2020	1840	Highly Concentrated	79.1%
2020/2021	2523	Highly Concentrated	88.4%
2021/2022	2070	Highly Concentrated	85.3%
2022/2023	2051	Highly Concentrated	82.8%
2023/2024	2295	Highly Concentrated	85.6%
2024/2025	2387	Highly Concentrated	88.5%
2025/2026	2517	Highly Concentrated	86.7%

Table 6-7 shows the HHI value for committed UCAP MW by LDA by delivery year. The HHI values are calculated by the committed UCAP MW in each delivery year for demand resources.

Table 6-7 HHI value for committed UCAP MW by LDA by delivery year: 2024/2025 and 2025/2026 Delivery Years[30]

Delivery Year	LDA	Committed UCAP MW	HHI Value	HHI Concentration
2024/2025	ATSI	541.0	2839	High
	ATSI-CLEVELAND	141.6	3081	High
	BGE	198.1	3006	High
	COMED	1,554.0	2993	High
	DAY	192.9	3696	High
	DEOK	221.9	3157	High
	DPL-SOUTH	46.0	3515	High
	EMAAC	672.3	2802	High
	MAAC	531.7	2154	High
	PEPCO	160.4	2545	High
	PPL	603.4	2355	High
	PS-NORTH	98.2	2336	High
	PSEG	187.5	2289	High
	RTO	2,915.7	2258	High
2025/2026	ATSI	615.4	2255	High
	ATSI-CLEVELAND	97.3	3262	High
	BGE	168.3	3679	High
	COMED	1,090.5	3119	High
	DAY	141.0	3899	High
	DEOK	159.6	4581	High
	DOM	673.5	3003	High
	DPL-SOUTH	65.0	3876	High
	EMAAC	491.0	3156	High
	MAAC	347.0	2747	High
	PEPCO	135.7	2568	High
	PPL	424.9	2513	High
	PS-NORTH	65.8	2613	High
	PSEG	163.1	2615	High
	RTO	1,627.8	2282	High

Market Performance

Table 6-8 shows the cleared Demand Resource UCAP MW by delivery year. Total cleared demand response UCAP MW in PJM decreased by 1,798.8 MW, or 22.3 percent, from 8,064.7 MW in the 2024/2025 Delivery Year to 6,265.9 MW in the 2025/2026 Delivery Year.

30 The RTO LDA refers to the rest of RTO.

The DR percent of capacity decreased by 0.7 percentage points, from 5.2 percent in the 2024/2025 Delivery Year to 4.5 percent in the 2025/2026 Delivery Year.

Table 6-8 Cleared Demand Resource UCAP MW: 2007/2008 through 2025/2026 Delivery Year

	UCAP (MW)		
	DR RPM Cleared	Total RPM Cleared	DR Percent Cleared
2007/2008	127.6	129,409.2	0.1%
2008/2009	559.4	130,629.8	0.4%
2009/2010	892.9	134,030.2	0.7%
2010/2011	962.9	134,036.2	0.7%
2011/2012	1,826.6	134,182.6	1.4%
2012/2013	8,740.9	141,295.6	6.2%
2013/2014	10,779.6	159,844.5	6.7%
2014/2015	14,943.0	161,214.4	9.3%
2015/2016	15,453.7	173,845.5	8.9%
2016/2017	13,265.3	179,773.6	7.4%
2017/2018	11,870.5	180,590.5	6.6%
2018/2019	11,435.4	175,996.0	6.5%
2019/2020	10,703.1	177,064.2	6.0%
2020/2021	9,445.7	174,023.8	5.4%
2021/2022	11,427.7	174,713.0	6.5%
2022/2023	8,866.2	150,465.2	5.9%
2023/2024	8,174.1	150,143.9	5.4%
2024/2025	8,064.7	154,362.5	5.2%
2025/2026	6,265.9	137,733.6	4.5%

Table 6-9 shows zonal monthly capacity market revenue to demand resources for 2025. Capacity market revenue increased in 2025 by $321.4 million, 275.5 percent, from $116.6 million in 2024 to $438.1 million in 2025. The increase in capacity market revenue was a result of the increase in capacity market clearing prices between the 2024/2025 and 2025/2026 Delivery Years. The RTO clearing price in the 2024/2025 BRA was $28.92/MW-Day compared to $269.92/MW-Day in the 2025/2026 BRA.

Table 6-9 Zonal monthly demand resource capacity revenue: 2025

Zone	January	February	March	April	May	June	July	August	September	October	November	December	Total
ACEC	$110,995	$100,253	$110,995	$107,414	$110,995	$331,192	$342,232	$342,232	$331,192	$342,232	$331,192	$342,232	$2,903,157
AEP, EKPC	$1,240,632	$1,120,571	$1,240,632	$1,200,612	$1,240,632	$8,449,197	$8,730,837	$8,730,837	$8,449,197	$8,730,837	$8,449,197	$8,730,837	$66,314,020
APS	$573,335	$517,851	$573,335	$554,841	$573,335	$3,970,252	$4,102,594	$4,102,594	$3,970,252	$4,102,594	$3,970,252	$4,102,594	$31,113,831
ATSI	$619,177	$559,256	$619,177	$599,203	$619,177	$6,040,952	$6,242,317	$6,242,317	$6,040,952	$6,242,317	$6,040,952	$6,242,317	$46,108,112
BGE	$448,300	$404,916	$448,300	$433,839	$448,300	$2,368,036	$2,446,970	$2,446,970	$2,368,036	$2,446,970	$2,368,036	$2,446,970	$19,075,644
COMED	$1,264,960	$1,142,544	$1,264,960	$1,224,155	$1,264,960	$8,002,210	$8,268,950	$8,268,950	$8,002,210	$8,268,950	$8,002,210	$8,268,950	$63,244,008
DAY	$174,561	$157,668	$174,561	$168,930	$174,561	$1,143,220	$1,181,327	$1,181,327	$1,143,220	$1,181,327	$1,143,220	$1,181,327	$9,005,249
DOM	$726,698	$656,372	$726,698	$703,256	$726,698	$8,976,273	$9,275,482	$9,275,482	$8,976,273	$9,275,482	$8,976,273	$9,275,482	$67,570,470
DPL	$783,183	$707,391	$783,183	$757,919	$783,183	$949,849	$981,511	$981,511	$949,849	$981,511	$949,849	$981,511	$10,590,450
DUKE	$662,025	$597,958	$662,025	$640,670	$662,025	$1,292,377	$1,335,456	$1,335,456	$1,292,377	$1,335,456	$1,292,377	$1,335,456	$12,443,662
DUQ	$108,120	$97,657	$108,120	$104,632	$108,120	$714,370	$738,183	$738,183	$714,370	$738,183	$714,370	$738,183	$5,622,489
JCPLC	$218,999	$197,805	$218,999	$211,934	$218,999	$815,429	$842,610	$842,610	$815,429	$842,610	$815,429	$842,610	$6,883,462
MEC	$334,147	$301,810	$334,147	$323,368	$334,147	$1,101,274	$1,137,983	$1,137,983	$1,101,274	$1,137,983	$1,101,274	$1,137,983	$9,483,370
PE	$481,583	$434,978	$481,583	$466,048	$481,583	$1,713,128	$1,770,232	$1,770,232	$1,713,128	$1,770,232	$1,713,128	$1,770,232	$14,566,087
PECO	$607,149	$548,392	$607,149	$587,563	$607,149	$2,390,735	$2,470,426	$2,470,426	$2,390,735	$2,470,426	$2,390,735	$2,470,426	$20,011,310
PEPCO	$224,452	$202,731	$224,452	$217,212	$224,452	$1,019,002	$1,052,969	$1,052,969	$1,019,002	$1,052,969	$1,019,002	$1,052,969	$8,362,179
PPL	$925,730	$836,143	$925,730	$895,868	$925,730	$3,444,557	$3,559,375	$3,559,375	$3,444,557	$3,559,375	$3,444,557	$3,559,375	$29,080,373
PSEG	$474,719	$428,779	$474,719	$459,406	$474,719	$1,853,541	$1,915,325	$1,915,325	$1,853,541	$1,915,325	$1,853,541	$1,915,325	$15,534,265
REC	$4,486	$4,052	$4,486	$4,342	$4,486	$18,625	$19,245	$19,245	$18,625	$19,245	$18,625	$19,245	$154,708
TOTAL	$9,983,251	$9,017,130	$9,983,251	$9,661,211	$9,983,251	$54,594,218	$56,414,025	$56,414,025	$54,594,218	$56,414,025	$54,594,218	$56,414,025	$438,066,846

Product Definition

Pre-Emergency and Emergency Load Response resources must register all resources with a specific response time. The options are to respond within 30, 60 or 120 minutes of a PJM dispatched event. The 30 minute prior notification is the default and applies unless a CSP obtains an exception from PJM due to physical operational limitations that prevent the Demand Resource Registration from reducing load within that timeframe.

Table 6-10 shows the amount of nominated MW and locations by product type and lead time for the 2024/2025 Delivery Year. Nominated MW are Pre-Emergency or Emergency Load Response registrations used to satisfy a CSP's committed MW position for a delivery year. PJM approved 2,681 locations, or 16.1 percent of all locations, which have 3,287.5 nominated MW, or 45.6 percent of all nominated MW, for exceptions to the 30 minute lead time rule for the 2024/2025 Delivery Year.

Table 6-10 Nominated MW and locations by product type and lead time: 2024/2025 Delivery Year

	Pre-Emergency		Emergency			
Lead Type	MW	Percent	MW	Percent	Total	Percent of Total
30 Minutes	3,797.5	96.7%	130.4	3.3%	3,927.9	54.4%
60 Minutes	264.3	89.4%	31.2	10.6%	295.5	4.1%
120 Minutes	2,908.9	97.2%	83.2	2.8%	2,992.0	41.5%
Total	6,970.7	96.6%	244.8	3.4%	7,215.5	100.0%

	Pre-Emergency		Emergency			
Lead Type	Locations	Percent	Locations	Percent	Total	Percent of Total
30 Minutes	13,775	98.8%	165	1.2%	13,940	83.9%
60 Minutes	330	96.5%	12	3.5%	342	2.1%
120 Minutes	2,293	98.0%	46	2.0%	2,339	14.1%
Total	16,398	98.7%	223	1.3%	16,621	100.0%

Table 6-11 shows the amount of nominated MW and locations by product type and lead time for the 2025/2026 Delivery Year. PJM approved 4,926 locations, or 23.4 percent of all locations, which have 4,357.8 nominated MW, or 54.5 percent of all nominated MW, for exceptions to the 30 minute lead time rule for the 2025/2026 Delivery Year.

Table 6-11 Nominated MW and locations by product type and lead time: 2025/2026 Delivery Year

	Pre-Emergency		Emergency			
Lead Type	MW	Percent	MW	Percent	Total	Percent of Total
30 Minutes	3,528.5	96.9%	113.3	3.1%	3,641.8	45.5%
60 Minutes	462.0	92.6%	37.0	7.4%	499.1	6.2%
120 Minutes	3,755.5	97.3%	103.2	2.7%	3,858.8	48.2%
Total	7,746.1	96.8%	253.5	3.2%	7,999.6	100.0%

	Pre-Emergency		Emergency			
Lead Type	Locations	Percent	Locations	Percent	Total	Percent of Total
30 Minutes	15,989	99.1%	141	0.9%	16,130	76.6%
60 Minutes	435	97.1%	13	2.9%	448	2.1%
120 Minutes	4,436	99.1%	42	0.9%	4,478	21.3%
Total	20,860	99.1%	196	0.9%	21,056	100.0%

The alternative notification times are 60 minutes and 120 minutes. The CSP must request an exception in writing, including the reason(s) for the requested exception. Once a location is granted a longer lead time, the resource does not need to resubmit for a longer lead time each delivery year.

The request for an exception must demonstrate one of four defined reasons:[31]

- The manufacturing processes for the Demand Resource Registration require gradual reduction to avoid damaging major industrial equipment used in the manufacturing process, or damage to the product generated or feedstock used in the manufacturing process;
- Transfer of load to backup generation requires time intensive manual process taking more than 30 minutes;
- Onsite safety concerns prevent location from implementing reduction plan in less than 30 minutes; or,
- The Demand Resource Registration is comprised of mass market residential customers or Small Commercial Customers which collectively cannot be notified of a Load Management Event within 30 minutes due to unavoidable communications latency, in which case the requested notification time shall be no longer than 120 minutes.

Table 6-12 shows the nominated MW and locations by product type and lead time of granted lead time exceptions for the 2025/2026 Delivery Year.[32]

Table 6-12 Nominated MW and locations of granted lead time exceptions: 2025/2026 Delivery Year

	60 Minutes		120 Minutes			
Reason	MW	Percent	MW	Percent	Total	Percent
Generation Start Time	50.4	1.2%	475.2	10.9%	525.6	12.1%
Manufacturing Damage	208.6	4.8%	2,257.4	51.8%	2,466.1	56.6%
Safety Problem	240.0	5.5%	1,126.2	25.8%	1,366.3	31.4%
Total	499.1	11.5%	3,858.8	88.5%	4,357.8	100.0%

	60 Minutes		120 Minutes			
Reason	Locations	Percent	Locations	Percent	Total	Percent
Generation Start Time	24	0.5%	1,491	30.3%	1,515	30.8%
Manufacturing Damage	250	5.1%	1,096	22.2%	1,346	27.3%
Safety Problem	174	3.5%	1,891	38.4%	2,065	41.9%
Total	448	9.1%	4,478	90.9%	4,926	100.0%

31 OATT Attachment DD-1, Section A.2(a).
32 Data for generation start time and mass market communication categories were combined based on confidentiality rules.

Prior to participating in the PJM Markets, CSPs must complete a registration in DR Hub which identifies the specific location(s) based on the unique EDC account number that will participate and their associated load reduction capability. Locations are identified by zone, street address and zip code and are not nodal. CSPs must maintain the accuracy of the registration information provided to PJM for each demand resource and each time the CSP registers the location or extends the registration, the CSP must review all information to ensure it is accurate and update as necessary. In order to register demand resources, the CSPs must classify locations according to the location's primary purpose or business use. CSPs first determine if the location's business use falls under one of the following primary categories: Hospitals, Industrial / Manufacturing, Multiple Dwelling Unit, Office Building, Residential, Retail Service, Correctional Facilities, Data Center, Data Center with Crypto Mining, or Schools. In cases where the location does not fit into one of the primary categories, the CSP selects from one of the following categories: Agriculture, Forestry and Fishing, Mining, Transportation, Communications, Electric, Gas and Sanitary Services or Services.[33] PJM had previously not been explicitly identifying demand response associated with data center load in the registration process. PJM was instead including nominated capacity and load reductions from data centers with crypto mining as a load reduction method under the plug load category. At the April 23, 2025, Markets and Reliability Committee, PJM members endorsed changes to Manual 11 to discontinue this practice. The adopted changes relocated the reference to data centers in the registration process from the load reduction method/plug load section to the business segment section and separately identifies data centers and data centers with crypto mining.[34]

Table 6-13 shows the nominated MW and locations by business segment for the 2025/2026 Delivery Year.

Table 6-13 Nominated MW and locations by business segment: 2025/2026 Delivery Year

Business Segment	Nominated MW (ICAP)	Percent of Total	Locations	Percent of Total
Industrial/Manufacturing	3,882.2	48.5%	3,490	16.6%
Schools	795.2	9.9%	4,028	19.1%
Transportation, Communications, Electric, Gas and Sanitary Services	534.1	6.7%	517	2.5%
Office Building	485.8	6.1%	1,271	6.0%
Services	477.3	6.0%	762	3.6%
Hospitals	421.5	5.3%	365	1.7%
Retail Service	322.9	4.0%	6,753	32.1%
Mining	284.4	3.6%	156	0.7%
Data Center	281.0	3.5%	53	0.3%
Residential	200.3	2.5%	3,113	14.8%
Agriculture, Forestry and Fishing	126.3	1.6%	273	1.3%
Data Center with Crypto Mining	115.2	1.4%	29	0.1%
Multiple Dwelling Unit	37.6	0.5%	206	1.0%
Correctional Facilities	35.7	0.4%	40	0.2%
Total	7,999.6	100.0%	21,056	100.0%

There are two ways to measure the load reductions of emergency demand response resources. The Firm Service Level (FSL) method for the summer period, measures the difference between a customer's peak load contribution (PLC) and its real-time load, multiplied by the loss factor (LF) to account for transmission and distribution line losses.[35] The Guaranteed Load Drop (GLD) method measures the minimum of: the comparison load minus real-time load multiplied by the loss factor; or the PLC minus the real-time load multiplied by the loss factor. The comparison load estimates what the load would have been if PJM did not declare a Load Management Event, similar to a CBL, by using a comparable day, same day, customer baseline, regression analysis or backup generation method. Limiting the GLD method to the minimum of the two calculations ensures reductions occur below the PLC, thus avoiding double counting of load reductions.[36]

With the introduction of the Winter Peak Load (WPL) concept, effective for the 2017/2018 Delivery Year, both the FSL and GLD methods are modified for the non-summer period. The FSL method measures compliance during the

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).
35 Real-time load is hourly metered load.
36 See 135 FERC ¶ 61,212 (2011).

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 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:

$$FSL\ Compliance_{Summer} = PLC - (Load \cdot LF)$$

$$FSL\ Compliance_{Non-Summer} = (WPL \cdot ZWWAF \cdot LF) - (Load \cdot LF)$$

$$GLD\ Compliance_{Summer} = Minimum\{(comparison\ load - Load) \cdot LF; PLC - (Load \cdot LF)\}$$

$$GLD\ Compliance_{Non-Summer} = Minimum\{(comparison\ load - Load) \cdot LF; (WPL \cdot ZWWAF \cdot LF) - (Load \cdot LF)\}$$

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.
42 162 FERC ¶ 61,159 (2018).

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 is 76 percent.[45]

PJM makes several unsupported assumptions when calculating ELCC for demand response resources. The PJM ELCC calculations do not account for the actual historical performance of DR in same way as thermal resources. PJM analysis showed that the ELCC reduction capability is overstated compared to the metered DR reduction capability.[46] This overstatement of performance is consistent with the observed performance of DR during Winter Storm Elliott. There was a significant disparity between the reported expected reduction capability provided by the CSPs and the actual observed energy reduction during Winter Storm Elliott. As a general matter, these resources are rarely used.

Beginning in May 2024, the MIC worked on a problem statement and issue charge regarding the alignment of demand response capacity availability hours with periods of reliability risk.[47] PJM proposed to expand the window to all hours. PJM also proposed to use coincident peak demand rather than the sum of noncoincident peak demands to measure the level of demand resources. The MMU supported the extension of availability to all hours, consistent with all other capacity resources. The MMU supported the proposal to measure all DR for the same coincident peak demand hour as a more accurate measure of the level of actual DR potential rather than the overstatement that has resulted from adding together all the DR from individual non coincident peak hours.

PJM also proposed to increase the ELCC derating factor from 76 percent to 94 percent, an increase of 24 percent in the value of demand resource MW. PJM's proposed ELCC value for DR is not consistent with the method PJM uses for generation resources. PJM's proposed ELCC for DR is based on assumed behavior and not based on the actual performance of demand resources during the same high EUE (expected unserved energy) hours used for other capacity resources. The current ELCC value for demand response is already overstated. As currently demand resources are inferior resources in the capacity market and the ELCC values, both existing and proposed, significantly overstate their contribution to reliability. The demand resources are rarely used. While PJM may call on demand resources as part of its emergency actions, there are no PJM rules governing the overall commitment and dispatch of demand resources as there are for all other capacity resources.[48] Demand resources do not have a must offer obligation in the energy market as all other capacity resources do. PJM rules do not indicate if, when and how demand resources should be called on for nonemergency events. PJM rules do not require the use of demand resources under defined conditions. PJM rules do not require that demand resources be called on during emergency events but leave all emergency actions to the discretion of PJM dispatchers. The proposed changes would increase the value of demand resources by almost a billion dollars ($880.7 M) without any actual change in the physical reality and without the type of detailed analysis applied to other capacity resources.[49] The proposed changes would simply pay demand response more for capacity without any increase in use and without any rules governing when demand response can or will be used for economic reasons and without a must offer obligation in the energy or capacity markets, and without any market power mitigation rules, without resource specific performance adjustments, and without addressing the

43 See PJM, Intra-PJM Tariffs, RAA, Schedule 6 (18.0.0), § 6.I.
44 See "Responses to Deficiency Letter – Capacity Market Reforms to Accommodate the Energy Transition," ER24-99-001. (December 1, 2023), at p 28.
45 See "*2025-2026 BRA ELCC Class Ratings*," <https://pjm.com/-/media/planning/res-adeq/elcc/2025-26-bra-elcc-class-ratings.ashx> (March 13, 2024).
46 See PJM, DR Availability Window: Additional DR ELCC Information, <https://pjm.com/-/media/committees-groups/committees/mic/2024/20240807/20240807-item-08b---pjm-dr-education.ashx> (August 7, 2024).
47 See *Approved Minutes from the Markets & Reliability Committee*, <https://pjm.com/-/media/committees-groups/committees/mrc/2024/20240627/20240627-consent-agenda-a---draft-mrc-minutes---05222024.ashx>.
48 See PJM Manual 13: Emergency Operations, §2.3.2. Rev. 97 (November 20, 2025).
49 See PJM, DR Availability Window – IMM Proposal, <https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2025/20250205/20250205-item-02-2---dr-availability-window---imm-proposal.pdf> (February 5, 2025).

fact that demand side performance metrics simply ignore increases in load above the WPL when called. PJM did not propose consistent changes to the treatment of demand resources in the summer. PJM proposed to make these changes to the ELCC value of demand response resources while ignoring significant issues with the treatment of other resource technologies. The result of this administrative change would also be to affect the ELCC of other classes and to make it appear that PJM is more reliable than it is. PJM filed these proposed changes on March 6, 2025, in Docket No. ER25-1525-000.[50] The IMM filed an answer and motion for leave to answer on April 14, 2025.[51] On May 5, 2025, in Docket No. ER25-1525-000, FERC accepted PJM's section 205 proposal to revise the RAA, effective with the 2027/2028 Delivery Year, that extends the Demand Resource availability window to 24 hours a day throughout the year and revises the definition of Winter Peak Load used in calculating Demand Resources' Winter Nominated Value in PJM's ELCC method, effective May 6, 2025.[52]

Table 6-14 shows the MW registered by measurement and verification method and by technology type for the 2025/2026 Delivery Year. For the 2025/2026 Delivery Year, 99.75 percent of the MW use the FSL method and 0.25 percent of the MW use the GLD measurement and verification method.

Table 6-14 Nominated MW by each demand response method: 2025/2026 Delivery Year

	Technology Type								
Measurement and Verification Method	On-site Generation MW	HVAC MW	Refrigeration MW	Lighting MW	Manufacturing MW	Water Heating MW	Other, Batteries or Plug Load MW	Total	Percent by type
Firm Service Level	1,258.3	1,892.9	210.8	792.0	3,659.3	24.4	141.6	7,979.3	99.75%
Guaranteed Load Drop	5.1	1.1	0.0	0.0	14.1	0.0	0.0	20.3	0.25%
Total	1,263.4	1,894.0	210.8	792.0	3,673.4	24.4	141.6	7,999.6	100.0%
Percent by method	15.8%	23.7%	2.6%	9.9%	45.9%	0.3%	1.8%	100.0%	

Table 6-15 shows the fuel type used in the onsite generators for the 2025/2026 Delivery Year in the emergency and pre-emergency programs. For the 2025/2026 Delivery Year, 1,263.4 MW of the 7,999.6 nominated MW, 15.8 percent, used onsite generation. Of the 1,263. 1,263.44 MW, 84.5 percent used diesel and 15.5 percent used natural gas, gasoline, oil, propane or waste products. Some DR registrations reflect a participant's reliance on behind the meter generation having environmental restrictions that limit the resource's ability to operate only in emergency conditions. Demand resources relying on behind the meter generation having environmental restrictions limiting the resource's ability to operate only in emergency conditions must register as emergency DR. EPA regulations require that Reciprocating Internal Combustion Engines (RICE) that do not meet EPA emissions standards (stationary emergency RICE) may operate for only 100 hours per year and only to provide emergency DR during an Energy Emergency Alert 2 (EEA2), or if there are five percent voltage/frequency deviations. PJM does not prevent emergency stationary RICE that does not meet emissions standards from participating in PJM markets as DR. Some emergency stationary RICE that does not meet emissions standards are now included in DR portfolios. PJM's DR Hub does not explicitly identify Reciprocating Internal Combustion Engines (RICE) generators, only whether it is an internal combustion engine. For the 2025/2026 Delivery Year, of the 253.5 MW registered as generation backed emergency DR, 251.4 MW, or 19.9 percent of all onsite generation, are backed by internal combustion engines. Stationary emergency RICE should be prohibited from participation as DR either when registered individually or as part of a portfolio if it cannot meet its capacity market obligations as a result of emissions standards.

50 See "Proposal to Extend Demand Resource Availability Window and Revise Calculation of Demand Resource Winter Nominated Value," Docket No. ER25-1525-000 (March 6, 2025).
51 See "Answer and Motion for Leave to Answer," Docket No. ER25-1525-000 (April 14, 2025).
52 191 FERC ¶ 61,103

Table 6-15 Onsite generation fuel type (MW): 2025/2026 Delivery Year

	2025/2026	
Fuel Type	MW	Percent
Diesel	1,068.1	84.5%
Natural Gas, Gasoline, Oil, Propane, Waste Products	195.3	15.5%
Total	1,263.4	100.0%

Table 6-16 shows the MW registered by measurement and verification method and by technology type for the 2024/2025 Delivery Year. For the 2024/2025 Delivery Year, 99.99 percent use the FSL method and 0.01 percent use the GLD measurement and verification method.

Table 6-16 Nominated MW by each demand response method: 2024/2025 Delivery Year

	Technology Type								
Measurement and Verification Method	On-site Generation MW	HVAC MW	Refrigeration MW	Lighting MW	Manufacturing MW	Water Heating MW	Batteries and Plug Load MW	Total	Percent by type
Firm Service Level	1,050.5	1,731.0	192.5	663.3	3,438.5	22.3	116.5	7,214.7	99.99%
Guaranteed Load Drop	0.0	0.7	0.0	0.0	0.1	0.0	0.0	0.8	0.01%
Total	1,050.5	1,731.7	192.5	663.3	3,438.6	22.3	116.5	7,215.5	100.0%
Percent by method	14.6%	24.0%	2.7%	9.2%	47.7%	0.3%	1.6%	100.0%	

Table 6-17 shows the fuel type used in the onsite generators for the 2024/2025 Delivery Year in the emergency and pre-emergency programs. For the 2024/2025 Delivery Year, 1,050.5 MW of the 7,215.5 nominated MW, 14.6 percent, use onsite generation. Of the 1,050.5 MW, 84.1 percent use diesel and 15.9 percent use natural gas, gasoline, oil, propane or waste products.

Table 6-17 Onsite generation fuel type (MW): 2024/2025 Delivery Year

	2024/2025	
Fuel Type	MW	Percent
Diesel	883.5	84.1%
Natural Gas, Gasoline, Oil, Propane, Waste Products	167.0	15.9%
Total	1,050.5	100.0%

Emergency and Pre-Emergency Event Reported Compliance

Capacity resources measure performance nodally, except for demand resources. PJM cannot dispatch demand resources by node with the current rules because demand resources are not registered to a node. Demand resources can be dispatched by subzone only if the subzone is defined before dispatch. Aggregation rules allow a demand resource that incorporates many small End Use Customers to span an entire zone, which is inconsistent with nodal dispatch.

Subzonal dispatch became mandatory for emergency demand resources in the 2014/2015 Delivery Year.[53] A subzone is defined by zip code, not by nodal location. If a registration has any location in the dispatched subzone, as defined by the zip code of the enrolled End Use Customer's address, the entire registration must respond. There are currently nine defined dispatchable subzones in PJM: APS_EAST, DOM_CHES, DOM_YORKTOWN, AECO_ENGLAND, JCPL_REDBANK, DOM_ASHBURN, DOM_DCA, DOM_PRINWILM and AEP_MARION.[54] The AEP_MARION subzone was added as a result of the June 14-16, 2022, performance assessment event in the Columbus, Ohio area of the AEP Zone.

PJM can remove a defined subzone, and make changes to the subzone, at their discretion. Subzones should not be removed once defined, as the subzone may need to be dispatched again in the future. The METED_EAST, PENELEC_EAST, PPL_EAST and DOM_NORFOLK Subzones were removed by PJM. The MMU recommends that, if PJM continues to use subzones for any purpose, PJM clearly define the role of subzones in the dispatch of demand response.

The subzone design and closed loop interfaces are related. PJM implemented closed loop interfaces with the stated purpose of improving the incorporation of reactive constraints into energy prices and to allow emergency DR to set price.[55] PJM applies closed loop interfaces so that it can use units needed for reactive support to set the energy price when they would not otherwise set price under the LMP algorithm. PJM also applies closed loop interfaces so that it can use emergency DR resources to set the real-time LMP when DR would not otherwise set price under the fundamental LMP logic. Of the 20 closed loop interface definitions, 11 (55 percent) were created for the purpose of allowing

53 OATT Attachment DD, § 11.
54 See "Load Management Subzones," <https://www.pjm.com/-/media/markets-ops/demand-response/subzone-definition-workbook.ashx> (Accessed January 13, 2023).
55 See PJM/Alstom. "Approaches to Reduce Energy Uplift and PJM Experiences," presented at the FERC Technical Conference: Increasing Real-Time and Day-Ahead Market Efficiency Through Improved Software, Docket No. AD10-12-006 (June 23, 2015) <http://www.ferc.gov/june-tech-conf/2015/presentations/m2-3.pdf>.

emergency DR to set price.[56] The closed loop interfaces created for the purpose of allowing emergency DR to set price are located in the Rest of RTO, MAAC, EMAAC, SWMAAC, DPL-SOUTH, ATSI, ATSI-CLEVELAND and BGE LDAs. These interfaces correspond to LDAs as defined in RPM.[57]

Demand resources can be dispatched for voluntary compliance during any hour of any day, but dispatched resources are not measured for compliance outside of the mandatory compliance window for each demand product. This will change beginning in the 2027/2028 Delivery Year when the mandatory compliance window will expand to 24 hours per day. A demand response event during a product's mandatory compliance window also may not result in a compliance score. When demand response events occur for partial hours under 30 minutes, the event is not measured for compliance.

Demand resources currently estimate five minute compliance with an hourly interval meter during PAIs. To accurately measure compliance on a five minute basis, a five minute interval meter is required. All other capacity resources require five minute interval meters, and demand resources should be no different. Demand resources are paid based on the average performance by registration for the duration of a demand response event. Demand response should measure compliance on a five minute basis to accurately report reductions during demand response events. Measuring compliance on a five minute basis would provide accurate information to the PJM system. The MMU recommends demand response event compliance be calculated on a five minute basis for all capacity resources and that the penalty structure reflect five minute compliance.[58]

Under the capacity performance design of the capacity market, compliance for potential penalties is measured for DR only during performance assessment intervals (PAI).[59]

The MMU recommended that demand response resources be treated as economic resources like all other capacity resources and therefore that the dispatch of demand response resources not automatically trigger a performance assessment interval (PAI) for CP compliance. Emergencies should be triggered only when PJM has exhausted all economic resources including demand response resources. For the first seven months of 2023, PJM declared an emergency if pre-emergency or emergency demand response were dispatched. But in an order issued July 28, 2023, effective July 30, 2023, FERC approved proposed revisions to PJM's Tariff to eliminate the dispatch of demand response as a trigger for calling an emergency and for defining a Performance Assessment Interval (PAI).[60] Table 6-18 shows the amount of nominated demand response MW, the required reserve margin and actual reserve margin for the 2024/2025 and 2025/2026 Delivery Years. There are 8,137.5 nominated MW of demand response for the 2025/2026 Delivery Year, 32.1 percent of the required reserve margin and 29.4 percent of the actual reserve margin for the 2025/2026 Delivery Year.[61]

Table 6-18 Demand response nominated MW compared to reserve margin: 2024/2025 and 2025/2026 Delivery Years[62]

Delivery Year	Demand Response Nominated MW	Required Reserve Margin	Demand Response Percent of Required Reserve Margin	Actual Reserve Margin	Demand Response Percent of Actual Reserve Margin
2024/2025	7,220.0	21,398.4	33.7%	24,856.8	29.0%
2025/2026	8,137.5	25,381.0	32.1%	25,116.0	32.4%

PJM will dispatch demand resources by zone or subzone, or within a PAI area. When PJM dispatches all demand resources in multiple connecting zones, PJM further degrades the nodal design of electricity markets. In that case, PJM allows compliance to be measured across zones within a compliance aggregation area (CAA) or an Emergency Action Area (EAA).[63] [64] A CAA, or EAA, 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

56 *See the 2018 Annual State of the Market Report for PJM, Volume 2:* Section 4, Energy Uplift, for additional information regarding all closed loop interfaces and the impacts to the PJM markets.
57 "PJM Manual 18: PJM Capacity Market," § 2.3.1, Rev. 62 (December 17, 2025).
58 "PJM Manual 18: PJM Capacity Market," § 8.7A, Rev. 62 (December 17, 2025).
59 OATT § 1 (Performance Assessment Hour).
60 See "Order Accepting Tariff Revisions Subject to Condition," Docket No. ER23-1996-000 (July 28, 2023).
61 See *2025 Annual State of the Market Report for PJM*, Section 5: Capacity Market, Table 5-7.
62 Nominated MW totals are Demand Response ICAP corresponding to Demand Response UCAP cleared in RPM auctions for each delivery year. The total nominated MW values do not reflect replacement transactions.
63 CAA is "a geographic area of Zones or sub-Zones that are electrically contiguous and experience for the relevant Delivery Year, based on Resource Clearing Prices of, for Delivery Years through May 31, 2018, Annual Resources and for the 2018/2019 Delivery Year and subsequent Delivery Years, Capacity Performance Resources, the same locational price separation in the Base Residual Auction, the same locational price separation in the First Incremental Auction, the same locational price separation in the Second Incremental Auction, or the same locational price separation in the Third Incremental Auction." OATT § 1.
64 PJM. "Manual 18: Capacity Market," § 8.7.2, Rev. 62 (December 17, 2025).

thus create incentives that CSPs will incorporate in their decisions about how to respond to PJM dispatch. The multiple zone approach is even less locational than the zonal and subzonal approaches and creates larger mismatches between the locational need for the resources and the actual response. If multiple zones within a CAA are called by PJM, a CSP will dispatch the least cost resources across the zones to cover the CSP's obligation. This can result in more MW dispatched in one zone that are locationally distant from the relief needed and no MW dispatched in another zone, yet the CSP could be considered 100 percent compliant and pay no penalties. More locational deployment of load management resources would improve efficiency. With full implementation of capacity performance, demand response will be dispatched by registrations within an area for which an Emergency Action is declared by PJM. PJM does not have the nodal location of each registration, meaning PJM will need to guess as to the useful demand response registration by registered location. The MMU recommends that demand resources be required to provide their nodal location. Nodal dispatch of demand resources would be consistent with the nodal dispatch of generation.

Definition of Compliance

PJM's reporting of load management events overstates the performance of demand side capacity resources. Limiting reported compliance to only positive values incorrectly reports compliance. Settlement locations with a negative load reduction value (load increase) are not included in compliance reporting by PJM within registrations or within demand response portfolios. A resource that has load above their PLC during a demand response event has a negative performance value. But PJM does not include the negative performance values in the net performance calculation. PJM limits reported compliance shortfall values to zero MW.

The MMU recommends that PJM correctly report compliance for demand side capacity resources to include negative values above PLC when calculating event compliance across hours and registrations.[65]

Emergency demand response resources that are also registered as economic resources have a calculated CBL for the emergency event days. Demand resources that are not registered as economic resources use the three day CBL type with the symmetrical additive adjustment for measuring energy reductions without the requirements of a Relative Root Mean Squared Error (RRMSE) Test required for all economic resources.[66] The CBL must use the RRMSE test to verify that it is a good approximation for real-time load usage.

The MMU recommends that PJM Manual 11 be revised to require, rather than recommend, that the RRMSE test be applied to all demand resources with a CBL.[67]

The CBL for a customer is an estimate of what load would have been if the customer had not responded to LMP and reduced load. The difference between the CBL and real-time load is the energy reduction. When load responds to LMP by using a behind the meter generator, the energy reduction should be capped at the generation output. Any additional energy reduction is a result of inaccuracy in the CBL estimate rather than an actual reduction. The MMU recommends capping demand reductions based entirely on behind the meter generation at the lower of the generator's economic maximum or actual generation output.

An extreme example makes clear the fundamental problems with the use of measurement and verification methods to define the level of power that would have been used but for the DR actions, and the payments to DR customers that result from these methods. The current rules for measurement and verification for demand resources make a bankrupt company, a customer that no longer exists due to closing of a facility or a permanently shut down company, or a company with a permanent reduction in peak load due to a partial closing of a facility, an acceptable demand response customer under some interpretations of the tariff, although it is the view of the MMU that such customers should not be permitted to be included as registered demand resources. Companies that remain in business, but with a substantially reduced load, can maintain their pre-bankruptcy FSL (firm service level to which the customer agrees to reduce in an event) commitment, which can be greater than or equal to the post-bankruptcy peak load. The customer agrees to reduce to a level which is greater than or equal to its new peak load after bankruptcy. When demand response events occur the customer would receive credit for 100 percent reduction, even though the customer took no

65 See "Market Monitor Report," MC Webinar <https://pjm.com/-/media/committees-groups/committees/mc/2023/20230620-webinar/item-04---imm-report.ashx> (Accessed July 6, 2023).

66 157 FERC ¶ 61,067 (2016).

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

action and could take no action to reduce load. This problem exists regardless of whether the customer is still paying for capacity. To qualify and participate as a demand resource, the customer must have the ability to reduce load. "A participant that has the ability to reduce a measurable and verifiable portion of its load, as metered on an EDC account basis."[68] Such a customer no longer has the ability to reduce load in response to price or a PJM demand response event. CSPs in PJM have and continue to register bankrupt customers as emergency or pre-emergency load response customers. PJM finds acceptable the practice of CSPs maintaining the registration of customers with a bankruptcy related reduction in demand that are unable, as a result, to respond to emergency events. Three proposals that included language to remove bankrupt customers from a CSP's portfolio failed at the June 7, 2017, Market Implementation Committee.[69] The registered customers that are bankrupt and the amount of registered MW cannot be released for reasons of confidentiality.

The metering requirement for demand resources is outdated, and has not kept up with the changes to PJM's market design. PJM moved to five minute settlements, but the metering requirement for demand resources remained at an hourly interval meter. It is impossible to measure energy usage on a five minute basis using an hourly interval meter. PJM will estimate real-time usage by prorating the hourly interval meter and assume if load is less than the CBL, that the reduction occurred during the required dispatch window. The meter reading is not telemetered to PJM in real time. The resource is allowed up to 60 days to report the data to PJM.[70] The MMU recommends that PJM adopt the ISO-NE five-minute metering requirements in order to ensure that dispatchers have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions so that they can accurately measure compliance and that data be provided to PJM within 24 hours.[71]

On September 19, 2024, the Commission issued an order denying the complaint by Enerwise Global Technologies seeking to use statistical sampling for measuring demand response performance when interval metering is available.[72] Commissioner Chang concurred with the Commission's determination and agreed that using actual metered interval data is the ideal method to measure and verify performance for demand-side resources. Commissioner Chang further noted that it is essential that resources that are procured and compensated in the markets actually deliver on their reliability and economic commitments.[73]

On October 8, 2025, a complaint was filed by Voltus, Inc. and Mission:data requesting the Commission require that PJM allow CSPs to use statistical sampling for residential customers that have interval meters.[74] On October 28, 2025, the MMU filed comments pointing out that using statistical sampling when actual interval meter data is available would degrade PJM's ability to accurately measure the MW of capacity available and the actual performance of that capacity and therefore degrade PJM's ability to maintain resource adequacy and to correctly determine efficient capacity market prices through supply and demand in the market. [75]

When demand resources are not dispatched during a mandatory response window, each CSP must test their portfolio to the levels of capacity commitment, but the testing requirements have been inadequate.[76]

For the 2023/2024 Delivery Year and subsequent delivery years, if a Demand Resource registration is not dispatched by PJM for a Load Management event in a delivery year, then the registration must be tested for a two-hour period between the hours of 11:00 EPT and 18:00 EPT of a non-NERC holiday weekday during June through October or November through March of the relevant delivery year, where the date and time are selected by PJM.[77] All registrations in a zone are tested simultaneously for two hours for each product type. Registration performance is calculated as the two hour average reduction.

68 OA Schedule 1 § 8.2.
69 There was one proposal from PJM, one proposal from a market participant and one proposal from the MMU. See *Approved Minutes from the Market Implementation Committee*, <http://www.pjm.com/-/media/committees-groups/committees/mic/20170607/20170607-minutes.ashx>.
70 "PJM Manual 11: Energy & Ancillary Services Market Operations," § 10.4.1, Rev. 136 (October 1, 2025).
71 See ISO-NE Tariff, Section III, Market Rule 1, Appendix E1 and Appendix E2, "Demand Response," <http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-e.pdf>. (Accessed October 17, 2017) ISO-NE requires that DR have an interval meter with five-minute data reported to the ISO and each behind the meter generator is required to have a separate interval meter. After June 1, 2017, demand response resources in ISO-NE must also be registered at a single node.
72 See "Order Denying Complaint re Enerwise Global Technologies, LLC v. PJM Interconnection," EL23-104-000 (July 28, 2023).
73 *Id*, Commissioner Chang Statement Concurring at 1.
74 Voltus, Inc. and Mission:data v. PJM Interconnection, L.L.C., Complaint of Voltus, Inc. and Mission:data, Docket No. EL26-4-000 (Oct. 8, 2025).
75 See "Comments of the Independent Market Monitor for PJM," Docket No. EL26-4-000 (October 28, 2025).
76 The mandatory response time for Capacity Performance DR is June through October and the following May between 10:00AM to 10:00PM EPT and November through April between 6:00AM through 9:00PM EPT. *See* PJM. "Manual 18: PJM Capacity Market," Rev. 62 (December 17, 2025).
77 "PJM Manual 18: PJM Capacity Market," § 8.7, Rev. 62 (December 17, 2025).

If less than 25 percent (by MW) of a CSP's total Demand Resources in a zone fail the test, the CSP may conduct re-tests limited to all registrations that failed to meet their seasonal nominated ICAP in the prior test, provided that such re-test(s) must be during the same season, at the same time of day and under approximately the same weather conditions as the prior test. If 25 percent or more (by MW) of a CSP's Demand Resources fail the test, the CSP may request PJM to schedule a one time retest limited to all registrations that failed to meet their seasonal nominated ICAP in the prior test. The request must be made before the 46th day after the test. PJM will select the date and time of the retest during the same season. For the initial PJM scheduled test, PJM schedules, on an alternating basis, one test during June through October or November through March for each delivery year that a test is required. On the first business day of a week, PJM provides notice of all zones to be tested during the following two week test window. The test window opens the first business day of the week following the notice. By 10:00 EPT the day before the test, PJM posts on its website, and notifies the CSPs directly, the test date and zones.[78] On the test date, CSPs are notified of the start time of the test through the same notification protocol used for an actual event. For any scheduled retest by PJM, by 10:00 EPT the day before the retest, PJM will posts on its website, and notifies the CSPs directly, the retest date. On the retest date, CSPs are notified of the start time of the retest through the same notification protocol used for an event.

While the testing revisions implemented with the 2023/2024 Delivery Year are an improvement, the MMU recommends that load management testing be initiated by PJM with advance notice to CSPs identical to the actual lead time required in an emergency in order to accurately represent the conditions of an emergency event.

Beginning in the 2024/2025 Delivery Year and subsequent delivery years, CSPs may elect to use performance data from a Load Management event that was not subject to a Non-Performance Assessment (a non-PAI LM event) as performance data for a PJM zonal test event.[79] Elections are made on or after June 1 and no later than July 14 after the delivery year in the DR Hub system. Data required for compliance evaluation must be submitted no later than July 14 after the delivery year. Only one event result (either test event or non-PAI LM event) for each end-use customer site will be used in the zonal test evaluation. The duration of the non-PAI LM event must be at least 30 minutes of a clock hour. The election of non-PAI LM events to be used as zonal test performance will be done at registration lead time level. The non-PAI LM event must have occurred in the same season as the PJM scheduled test. For purposes of this election, the calculated reduction value for a registration in the non-PAI LM event is the average of the registration's hourly reductions within the product period hourly window.

The ability for test performance to be a substitute for event performance, coupled with the absence of nonperformance penalties, weakens the incentive to perform during non-PAI events. Emergency demand response resources have the same obligation to perform when called upon, regardless of whether the dispatch event occurs as part of a PAI or not.[80] There is no reason therefore to allow CSPs the optionality of testing in lieu of using non-PAI event performance.

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.[81] 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

78 See "Demand Response Test Schedule," <https://pjm.com/markets-and-operations/demand-response/demand-response-test-schedule> (Accessed July 18, 2023).
79 "PJM Manual 18: PJM Capacity Market," § 8.7, Rev. 62 (December 17, 2025).
80 OATT Attachment K, § 8.5.
81 Not all products received penalties or existed in every delivery year. For example, the Base and Capacity Performance products were not an option for the 2020/2021 Delivery Year.

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.

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 98.7 percent of nominated MW for the 2025/2026 Delivery Year registered under the full program option. There are 1.3 percent of nominated MW for the 2025/2026 Delivery Year registered as capacity only option. Demand resources clear the capacity market like all other capacity resources and the dispatch of demand resources should not trigger a scarcity event. The strike price is set by the CSP before the delivery year starts and cannot be changed during the delivery year. The demand resource energy payments are equal to the higher of hourly zonal LMP or the strike price energy offer made by the participant, including a dollar per MWh minimum dispatch price and an associated shutdown cost. Demand resources should not be permitted to offer above $1,000 per MWh without cost justification or to include a shortage penalty in the offer. FERC has stated clearly that demand resources in the capacity market must verify costs above $1,000 per MWh, unless they are capacity only: "We clarify, however,

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).
84 *Id.*

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]

Table 6-21 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices for the 2024/2025 Delivery Year. The majority of participants, 83.3 percent of locations and 52.8 percent of nominated MW, had a minimum dispatch price between $1,550 and $1,849 per MWh, the maximum price allowed for the 2024/2025 Delivery Year. Almost all registrations, 99.7 percent of locations and 98.1 percent of nominated MW have a dispatch price above $1,000 per MWh. The shutdown cost of resources with $1,000 to $1,275 per MWh strike prices had the highest average at $137.74 per location and $109.14 per nominated MW.

Table 6-21 Distribution of registrations and associated MW in the full option across ranges of minimum dispatch: 2024/2025 Delivery Year

Ranges of Strike Prices ($/MWh)	Locations	Percent of Total	Nominated MW (ICAP)	Percent of Total	Shutdown Cost per Location	Shutdown Cost Per Nominated MW (ICAP)
$0-$1,000	49	0.3%	132.6	1.9%	$7.14	$2.64
$1,000-$1,275	2,323	14.3%	2,931.6	41.2%	$137.74	$109.14
$1,275-$1,550	340	2.1%	293.6	4.1%	$0.31	$0.36
$1,550-$1,849	13,534	83.3%	3,755.3	52.8%	$15.37	$55.40
Total	16,246	100.0%	7,113.2	100.0%	$32.53	$74.29

Table 6-22 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices for the 2025/2026 Delivery Year. The majority of participants, 76.0 percent of locations and 43.8 percent of nominated MW, have a minimum dispatch price between $1,550 and $1,849 per MWh, the maximum price allowed for the 2025/2026 Delivery Year. Almost all registrations, 99.7 percent of locations and 98.0 percent of nominated MW have a dispatch price above $1,000 per MWh. The shutdown cost of resources with $0 to $1,000 per MWh strike prices have the highest average at $175.34 per location, while the shutdown cost of resources with $1,000 to $1,275 per MWh strike prices have the highest average at $87.73 per nominated MW.

Table 6-22 Distribution of registrations and associated MW in the full option across ranges of minimum dispatch: 2025/2026 Delivery Year

Ranges of Strike Prices ($/MWh)	Locations	Percent of Total	Nominated MW (ICAP)	Percent of Total	Shutdown Cost per Location	Shutdown Cost Per Nominated MW (ICAP)
$0-$1,000	59	0.3%	156.1	2.0%	$175.34	$66.25
$1,000-$1,275	4,459	21.5%	3,784.9	47.9%	$74.47	$87.73
$1,275-$1,550	447	2.2%	497.1	6.3%	$0.21	$0.19
$1,550-$1,849	15,738	76.0%	3,460.2	43.8%	$11.15	$50.70
Total	20,703	100.0%	7,898.4	100.0%	$25.02	$65.57

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).

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.

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 2025/2026 Delivery Years.

Table 6-23 Nominated MW of price responsive demand: 2020/2021 through 2025/2026 Delivery Years

Delivery Year	RTO	MAAC	EMAAC	SWMAAC	DPL SOUTH	PEPCO	BGE
2020/2021	558.0	558.0	58.0	500.0	27.0	170.0	330.0
2021/2022	510.0	510.0	75.0	435.0	35.7	195.0	240.0
2022/2023	230.0	230.0	40.0	190.0	19.6	110.0	80.0
2023/2024	235.0	235.0	38.0	197.0	15.4	110.0	87.0
2024/2025	305.0	305.0	35.0	270.0	13.0	110.0	160.0
2025/2026	224.0	224.0	14.0	210.0	0.0	75.0	135.0

The cleared PRD is credited the adjusted zonal clearing price of the LDA in which they cleared. The PRD credits are charged to the load of those LDAs by inclusion in the RPM net load price A PRD Provider receives a PRD Credit for each approved Price Responsive Demand registration on a given day. PRD Credits are determined as:[92]

PRD Credit
= [(Share of Zonal Nominal PRD Value committed in Base Residual Auction
** (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)
** Final Zonal RPM Scaling Factor * FPR * Final Zonal Capacity Price)*

plus

(Share of Zonal Nominal PRD Value committed in Third Incremental Auction
** (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)
** Final Zonal RPM Scaling Factor * FPR * Final Zonal Capacity Price*
** Third Incremental Auction Component of Final Zonal Capacity Price stated as a Percentage)]*

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

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).

Effective with the 2022/2023 Delivery Year, the factor equal to (Zonal Weather-Normalized Peak Load for the summer concluding prior to the commencement of the Delivery Year / Final Zonal Peak Load Forecast for the delivery year) is eliminated in the calculation of the PRD Credit.

Table 6-24 shows the PRD Credits for the 2020/2021 through 2025/2026 Delivery Years.[93]

Table 6-24 PRD Credits for 2020/2021 through 2025/2026 Delivery Years

Delivery Year	PRD Credit
2020/2021	$23,649,865.05
2021/2022	$38,282,769.14
2022/2023	$10,702,158.12
2023/2024	$6,169,725.27
2024/2025	$10,782,581.08
2025/2026	$19,110,641.10

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:

PRD Commitment Compliance Penalty
= MW shortfall in the Sub-zone/ Zone
** Delivery Year Forecast Pool Requirement*
** PRD Commitment Compliance Penalty Rate*

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

93 The total credits for PRD were downloaded as of January 13, 2026, and may change as a result of continued PJM billing updates.

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).

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 to instructions from PJM. PRD should be held to the same standard during a PAI event. The MMU recommends that PRD be required to respond during a PAI, regardless of whether the real-time LMP at the applicable location meet or exceeds the PRD strike price, to be consistent with all CP resources.

Load Management Events – June through August, 2025

PJM dispatched pre-emergency load management during periods of hot weather on June 23-25, July 28-29 and August 11, 2025.

During the June and July events, long lead time (120 minute) and short lead-time (60 minute) pre-emergency resources were dispatched each day. PJM never declared a level EEA2 emergency, the requirement for deployment of emergency demand response resources, and therefore only dispatched pre-emergency demand resources.[100] PJM did not dispatch quick lead time (30 minute) demand resources. The 60 and 120 minute lead time resources have $1,425 per MWh and $1,100 per MWh maximum strike prices compared to the $1,849 per MWh maximum strike price for 30 minute resources.

Load management compliance data for non-PAI event performance is due 45 days after the month in which the event occurs.[101] Data supporting requested energy settlements is due 60 days after an event.[102]

Table 6-25 through Table 6-27 show the deployment and release times, by lead time, for June 23-25, 2025.

Table 6-25 Demand Resource Deployment and Release Times: June 23, 2025

Deploy Time (EPT)	Release Time (EPT)	Resource Type	Lead Time	Zones
1500	2200	Pre-emergency	120 minute	AECO, BGE, DOM, DPL, METED, PECO, PENELEC, PEPCO, PPL, PSEG
1500	2200	Pre-emergency	60 minute	AECO, BGE, DOM, DPL, METED, PECO, PENELEC, PEPCO, PPL, PSEG

99 October 31 Filing, Attachment B, Proposed Revised OATT § 10A (c).
100 OATT Attachment K, § 8.5.
101 "PJM Manual 18: PJM Capacity Market," § 4.3.1, Rev. 62 (December 17, 2025).
102 "PJM Manual 11: Energy & Ancillary Services Market Operations," § 10.4.1, Rev. 136 (October 1, 2025).

Table 6-26 Demand Resource Deployment and Release Times: June 24, 2025

Deploy Time (EPT)	Release Time (EPT)	Resource Type	Lead Time	Zones
1500	2200	Pre-emergency	120 minute	BGE, DOM, PECO, PEPCO
1530	2200	Pre-emergency	120 minute	AECO, DPL, JCPL, METED, PENELEC, PPL, PSEG
1600	2200	Pre-emergency	120 minute	AEP, APS, DAY, DUQ
1630	2200	Pre-emergency	120 minute	ATSI, COMED, DEOK, EKPC
1500	2200	Pre-emergency	60 minute	BEG, DOM, PECO, PEPCO
1530	2200	Pre-emergency	60 minute	AECO, DPL, JCPL, METED, PENELEC, PPL, PSEG
1600	2200	Pre-emergency	60 minute	AEP, APS, DAY, DUQ
1630	2200	Pre-emergency	60 minute	ATSI, COMED, DEOK, EKPC

Table 6-27 Demand Resource Deployment and Release Times: June 25, 2025

Deploy Time (EPT)	Release Time (EPT)	Resource Type	Lead Time	Zones
1500	1745	Pre-emergency	120 minute	APS
1500	1810	Pre-emergency	120 minute	AECO, BGE, DPL, JCPL, METED, PECO, PENELEC, PEPCO, PPL, PSEG
1500	1900	Pre-emergency	120 minute	DOM
1500	1745	Pre-emergency	60 minute	APS
1500	1810	Pre-emergency	60 minute	AECO, BGE, DPL, JCPL, METED, PECO, PENELEC, PEPCO, PPL, PSEG
1500	1900	Pre-emergency	60 minute	DOM

Table 6-28 and Table 6-29 show the deployment and release times, by lead time, for July 28-29, 2025.

Table 6-28 Demand Resource Deployment and Release Times: July 28, 2025

Deploy Time (EPT)	Release Time (EPT)	Resource Type	Lead Time	Zones
1645	2100	Pre-emergency	120 minute	BGE, DOM, PEPCO
1545	2100	Pre-emergency	60 minute	BGE, DOM, PEPCO

Table 6-29 Demand Resource Deployment and Release Times: July 29, 2025

Deploy Time (EPT)	Release Time (EPT)	Resource Type	Lead Time	Zones
1500	2045	Pre-emergency	120 minute	ATSI, BGE, DOM, PEPCO
1530	2115	Pre-emergency	120 minute	AEP, EKPC
1600	2130	Pre-emergency	120 minute	AECO, DPL, JCPL, METED, PECO, PENELEC, PPL, PSEG
1800	2145	Pre-emergency	120 minute	APS, COMED, DAY, DEOK, DUQ
1400	2045	Pre-emergency	60 minute	ATSI, BEG, DOM, PEPCO
1430	2115	Pre-emergency	60 minute	AEP, EKPC
1500	2130	Pre-emergency	60 minute	AECO, DPL, JCPL, METED, PECO, PENELEC, PPL, PSEG
1700	2145	Pre-emergency	60 minute	APS, COMED, DAY, DEOK, DUQ

During the August 11 event, long lead time (120 minute), short lead-time (60 minute) and quick lead-time (30 minute) pre-emergency resources were dispatched. PJM also dispatched short lead-time (60) minute and quick lead-time (30) minute emergency demand response resources after declaring a level EEA2 emergency. Table 6-30 shows the deployment and release times, by lead time, for August 11, 2025.

Table 6-30 Demand Resource Deployment and Release Times: August 11, 2025

Deploy Time (EPT)	Release Time (EPT)	Resource Type	Lead Time	Zones
1045	2000	Pre-emergency	120 minute	BGE
1000	2000	Pre-emergency	60 minute	BGE
1000	2000	Pre-emergency	30 minute	BGE
1515	1715	Emergency	60 minute	BGE
1445	1715	Emergency	30 minute	BGE

The emergency procedures employed during June 23-25, July 28-29 and August 11, 2025 did not trigger a PAI. There are no penalties for demand resources failing to perform outside of a PAI. In an order issued July 28, 2023, effective July 30, 2023, FERC approved proposed revisions to PJM's Tariff to eliminate the dispatch of demand response as a trigger for calling an emergency and for defining a Performance Assessment Interval (PAI).[103] Under the prior rules, PJM would declare a PAI if pre-emergency or emergency demand response were dispatched. The new rules mean that demand resources may be dispatched both as part of, and absent, a PAI. While demand resources dispatched during a PAI continue to be subject to Non-Performance Assessment charges, demand resources dispatched outside of a PAI are not subject to any event specific penalties.[104] If a demand resource is dispatched only outside of Performance Assessment Events for the delivery year, its performance for the delivery year may be determined based solely on a Load Management Test.[105] Beginning in the 2024/2025 Delivery Year and subsequent delivery years, CSPs may elect to use performance data from a load management event that was not subject to a Non-Performance Assessment (a non-PAI load management event) as performance data for a PJM zonal test event.[106]

Given that calling demand resources no longer triggers a PAI, the MMU recommended in 2023 that PJM revise the performance requirements for demand resources to include an event specific measurement for dispatch occurring outside of Performance Assessment Events and penalties for nonperformance. Load management resources have the same obligation to perform when called upon, regardless of whether the dispatch event occurs as part of a PAI.[107] There is no reason to allow CSPs the optionality of testing in lieu of using non-PAI event performance. If demand resources are only subject to non-PAI dispatch events during the delivery year, their ability to meet their obligations are best defined by their actual operational performance rather than through a scripted test.

Load management resources overall failed to perform to their committed ICAP level during the June 23-25, July 28-29 and August 11, 2025 dispatch events. Load management resources were evaluated based on their ability to reduce load to their nominated Firm Service Level (FSL). Customer Base Line (CBL) is an hourly estimate of the load level of a demand resource in the absence of a demand response event. The expected hourly reduction of each resource is defined as the difference between the CBL and the FSL. The actual hourly reduction is defined as the difference between the CBL and the metered load of the resource adjusted for losses. If a resource reduces to its FSL, then its actual reduction equals its expected reduction. The correct metric is (CBL – metered load)/(CBL – FSL). This metric provides a better assessment of demand response performance than simply comparing metered load to FSL. PJM's metric is (PLC – metered load)/ICAP. During Winter Storm Elliott, demand resource loads were already at a reduced level when dispatched. While deemed to have generally met their ICAP commitments, there was very little incremental reduction provided in order to reach their FSL. The difference between CBL and FSL provides a better estimate of the expected incremental reduction. If a dispatched registration has a CBL equal to or less than the FSL, the expected incremental reduction is zero.

Based on this metric, demand resources provided 69.3 percent of their expected reduction on June 23, 70.6 percent of their expected reduction on June 24 and 68.8 percent of their expected reduction on June 25. Demand resources provided 72.0 percent of their expected reduction on July 28 and 69.6 percent of their expected reduction on July 29. Demand resources provided 49.3 percent of their expected reduction on August 11. Table 6-31 through Table 6-33 summarize these results.

Table 6-31 Demand Resource Expected and Actual Performance: June 23-25, 2025

Date	Actual Reduction (MWh)	Expected Reduction (MWh)	Percent Performance
23-Jun-25	6,614	9,540	69.3%
24-Jun-25	15,506	21,963	70.6%
25-Jun-25	3,675	5,339	68.8%
Total	25,796	36,842	70.0%

103 See "Order Accepting Tariff Revisions Subject to Condition," Docket No. ER23-1996-000 (July 28, 2023).
104 "PJM Manual 18: PJM Capacity Market," § 8.6, Rev. 62 (December 17, 2025).
105 "PJM Manual 18: PJM Capacity Market," § 8.7, Rev. 62 (December 17, 2025).
106 "PJM Manual 18: PJM Capacity Market," § 8.7, Rev. 62 (December 17, 2025).
107 OATT Attachment K, § 8.5.

Table 6-32 Demand Resource Expected and Actual Performance: July 28-29, 2025

Date	Actual Reduction (MWh)	Expected Reduction (MWh)	Percent Performance
28-Jul-25	1,866	2,590	72.0%
29-Jul-25	13,128	18,868	69.6%
Total	14,994	21,458	69.9%

Table 6-33 Demand Resource Expected and Actual Performance: August 11, 2025

Date	Actual Reduction (MWh)	Expected Reduction (MWh)	Percent Performance
11-Aug-25	744	1,510	49.3%
Total	744	1,510	49.3%

Figure 6-2 though Figure 6-4 show the hourly expected and actual reduction values for June 23-25, July 28-29 and August 11, 2025

Figure 6-2 Hourly demand resource expected and actual performance: June 23-25, 2025

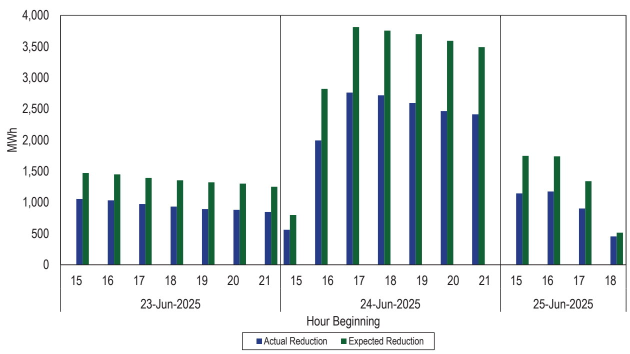


Figure 6-3 Hourly demand resource expected and actual performance: July 28-29, 2025

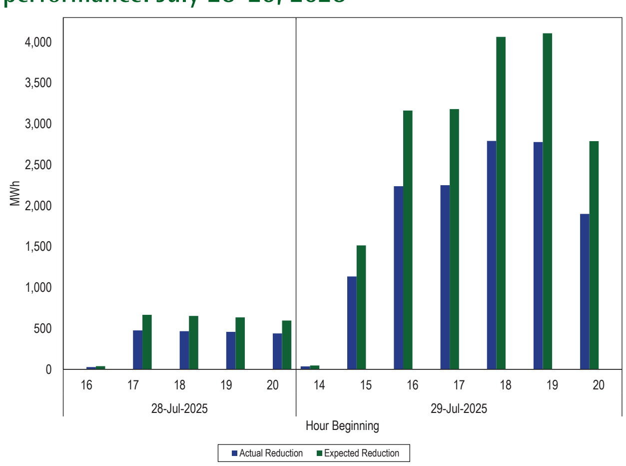
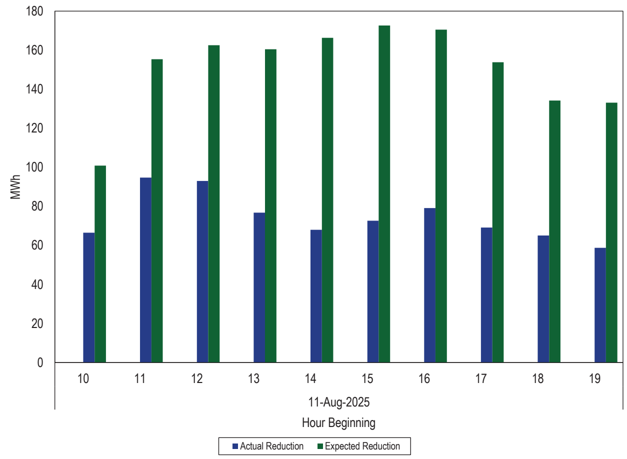


Figure 6-4 Hourly demand resource expected and actual performance: August 11, 2025



The failure of demand resources overall to perform to their committed ICAP level is further evidenced by observing the metered load relative to the Peak Load Contribution (PLC) and FSL. As shown in Figure 6-5 through Figure 6-7, demand resources overall failed to reduce load to their FSL during the June, July and August, 2025 dispatch events.

Figure 6-5 Demand resource metered load compared to PLC and FSL: June 23-25, 2025

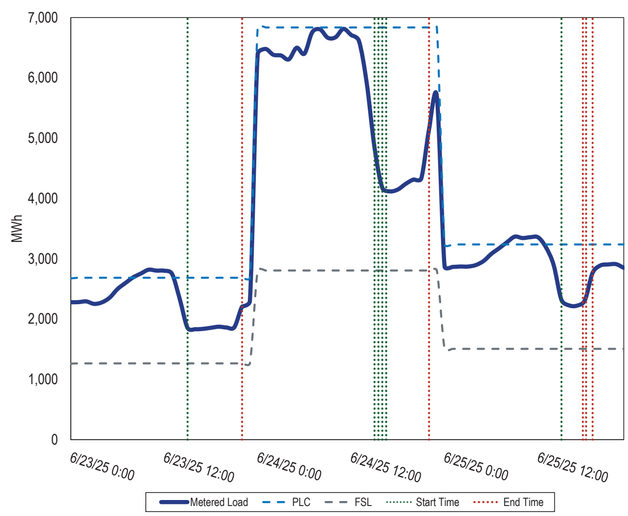


Figure 6-6 Demand resource metered load compared to PLC and FSL: July 28-29, 2025

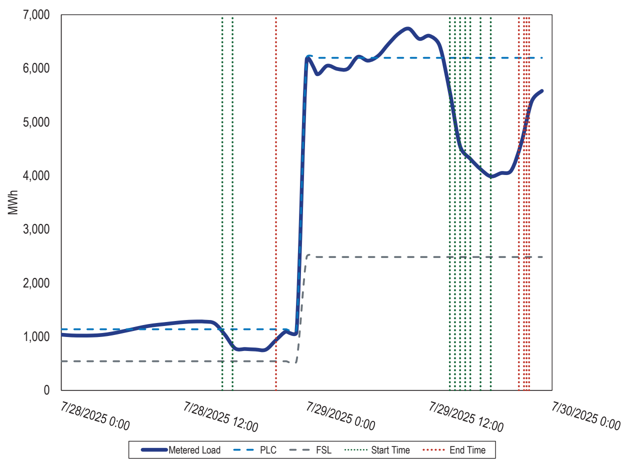
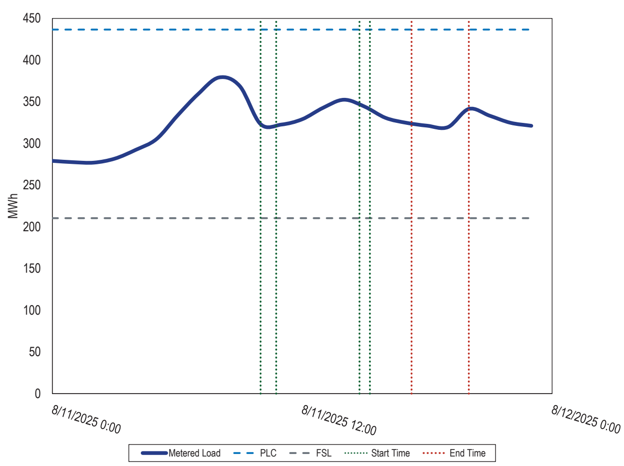


Figure 6-7 Demand resource metered load compared to PLC and FSL: August 11, 2025



Load management demand resources are compensated at real-time LMP for their actual load reduction determined as the difference between the CBL and the metered load. Load management demand resources are paid an emergency load response energy credit equal to their actual load reduction multiplied by the real-time LMP. Load management demand resources are made whole to their offer value which includes their emergency bid price, or strike price and shutdown costs. If the emergency load response energy credit is insufficient to cover the emergency bid based reduction plus shutdown costs, they will receive an emergency load response make whole credit for the difference.

$$\begin{aligned}&\textit{Total Emergency Energy Revenue}\\&\quad = \textit{Daily Load Response Emergency Credits}\\&\quad + \textit{Emergency Load Response Make Whole Credit}\end{aligned}$$

where,

$$\begin{aligned}&\textit{Emergency Load Response Make Whole Credit}\\&\quad = \textit{Emergency Bid cost} + \textit{Emergency Shutdown cost}\\&\quad - \textit{Daily Load Response Emergency Credits}\end{aligned}$$

Table 6-34 through Table 6-36 show the daily emergency energy payments to load management demand resources for the June, July and August, 2025 dispatch events. For the June 23-25 dispatch event, real-time LMP was sufficient to cover 51 percent of the total emergency energy payments with the remainder compensated through make whole credits. For the July 28-29 dispatch event, real-time LMP was sufficient to cover 18 percent of the total emergency energy payments with the remainder compensated through make whole credits. For the August 11 dispatch event, real-time LMP was sufficient to cover 11 percent of the total emergency energy payments with the remainder compensated through make whole credits. These energy payments are in addition to the capacity market revenues received by load management demand resources. For the 2025/2026 Delivery Year, capacity market revenues paid to load management demand resources average $55.5 million per month.

Table 6-34 Demand resource emergency energy payments: June 23-25, 2025

Date	Real-Time Actual Relief (MWh)	Average Emergency Bid Price ($/MWh)	Average Emergency Shutdown Cost	Average LMP ($/MWh)	Emergency Load Response Energy Credit	Emergency Load Response Energy Make-Whole Credit	Total Emergency Energy Revenue	Average Total Payment ($/MWh)
23-Jun-25	7,397	$1,143	$48	$555	$4,105,528	$3,616,557	$7,722,084	$1,044
24-Jun-25	19,096	$1,134	$82	$662	$12,639,948	$8,862,562	$21,502,510	$1,126
25-Jun-25	5,149	$1,132	$72	$212	$1,092,332	$4,347,255	$5,439,587	$1,056
Total	31,642	$1,136	$67	$564	$17,837,807	$16,826,374	$34,664,181	$1,096

Table 6-35 Demand resource emergency energy payments: July 28-29, 2025

Date	Real-Time Actual Relief (MWh)	Average Emergency Bid Price ($/MWh)	Average Emergency Shutdown Cost	Average LMP ($/MWh)	Emergency Load Response Energy Credit	Emergency Load Response Energy Make-Whole Credit	Total Emergency Energy Revenue	Average Total Payment ($/MWh)
28-Jul-25	2,140	$1,103	$3	$272	$582,748	$1,492,173	$2,074,921	$969
29-Jul-25	18,977	$1,135	$82	$189	$3,583,311	$18,009,167	$21,592,478	$1,138
Total	21,117	$1,119	$42	$197	$4,166,059	$19,501,339	$23,667,399	$1,121

Table 6-36 Demand resource emergency energy payments: August 11, 2025

Date	Real-Time Actual Relief (MWh)	Average Emergency Bid Price ($/MWh)	Average Emergency Shutdown Cost	Average LMP ($/MWh)	Emergency Load Response Energy Credit	Emergency Load Response Energy Make-Whole Credit	Total Emergency Energy Revenue	Average Total Payment ($/MWh)
11-Aug-25	805	$1,739	$6	$185	$148,930	$1,217,333	$1,366,264	$1,696

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 6-37 shows the average hourly HHI for each month and the average hourly HHI for January 1, 2024, through December 31, 2025. The ownership of economic demand response resources was highly concentrated in 2024 and 2025.[109] Table 6-37 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 2025. The HHI for economic demand response in 2025 increased by 254, 2.9 percent, from 8684 in 2024 to 8938 in 2025.

Table 6-37 Average hourly MWh HHI and market concentration in the economic program: 2024 and 2025[110]

	Average Hourly MWh HHI			Top Four CSPs Share of Reduction			Top Four CSPs Share of Credit		
Month	2024	2025	Percent Change	2024	2025	Change in Percent	2024	2025	Change in Percent
Jan	9043	8382	(7.3%)	100.0%			100.0%		
Feb	8806	8017	(9.0%)						
Mar	9856	8510	(13.7%)						
Apr	9566	8547	(10.7%)	100.0%			100.0%		
May	9722	8655	(11.0%)	100.0%			100.0%		
Jun	8405	9228	9.8%	99.8%			99.7%		
Jul	8249	8963	8.7%	99.6%			99.4%		
Aug	7913	8985	13.5%	99.9%			99.8%		
Sep	8052	9166	13.8%						
Oct	9400	9402	0.0%						
Nov	8121	9601	18.2%						
Dec	7745	10000	29.1%						
Total	8684	8938	2.9%	99.9%			99.8%		

108 Also known in the PJM Market Rules as the Economic Load Response Program.
109 All HHI calculations in this section are at the parent company level.
110 Omitted reduction and credit share values are based on confidentiality rules that require published data to include more than four owners.

Market Performance

Table 6-38 shows the total MW reported reductions made by participants in the economic program and the total credits paid for these reported reductions in 2010 through 2025. The average credits per MWh paid increased by $8.95 per MWh, 18.1 percent, from $49.36 per MWh in 2024 to $58.30 per MWh in 2025. Curtailed energy for the economic program was 413,524 MWh in 2025, an increase of 167,807 MWh, 68.3 percent, as compared to curtailed energy for the economic program in 2024. Total credits paid for the economic load response program in 2025 were $24,109,587, an increase of $11,981,626, 98.8 percent, compared to the total credits paid for the economic load response program in 2024.

Table 6-38 Credits paid to economic program participants: 2010 through 2025

	Total MWh	Total Credits	$/MWh
2010	72,757	$3,088,049	$42.44
2011	17,398	$2,052,996	$118.00
2012	144,285	$9,278,942	$64.31
2013	133,963	$8,711,873	$65.03
2014	146,301	$17,820,063	$121.80
2015	121,129	$7,983,488	$65.91
2016	81,908	$3,550,535	$43.35
2017	62,622	$2,709,335	$43.27
2018	49,441	$2,548,575	$51.55
2019	24,595	$979,266	$39.82
2020	9,425	$329,119	$34.92
2021	18,851	$1,163,113	$61.70
2022	103,645	$10,893,489	$105.10
2023	56,303	$3,573,199	$63.46
2024	245,717	$12,127,961	$49.36
2025	413,524	$24,109,587	$58.30

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.[111] 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 .[112] 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 6-8 shows monthly economic demand response credits and MWh, from 2010 through 2025.

Figure 6-8 Economic program credits and MWh by month: 2010 through 2025

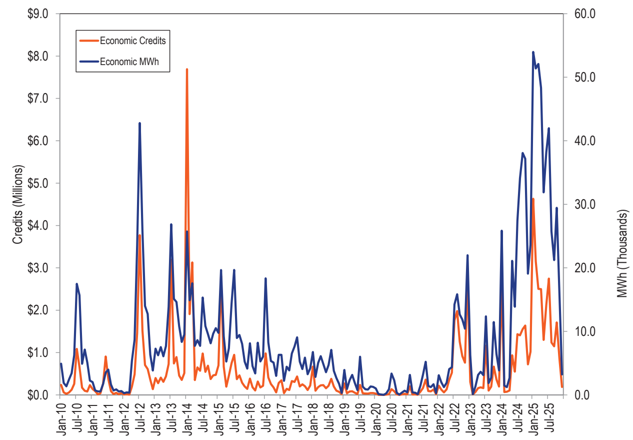


Table 6-39 shows performance for 2024 and 2025 in the economic program by control zone. Total reported reductions under the economic program increased by 167,807 MWh, 68.3 percent, from 245,717 MWh in 2024 to 413,524 MWh in 2025. Total revenue under the economic program increased by $12.0 million, 98.8 percent, from $12.1 million in 2024 to $24.1 million in 2025.[113]

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.[114] The zonal allocation is shown in Table 6-39.

111 "PJM. Manual 11: Energy & Ancillary Services Market Operations," § 10.4.5, Rev. 136 (October 1, 2025).

112 *Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 831, 157 FERC ¶ 61,115 (2016) ("Order No. 831").

113 Economic demand response reductions that are submitted to PJM for payment but have not received payment are not included in Table 6-39. Payments for Economic demand response reductions are settled monthly.

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

Table 6-39 Economic program participation by zone: 2024 and 2025

	Credits			MWh Reductions			Credits per MWh Reduction		
Zone	2024	2025	Percent Change	2024	2025	Percent Change	2024	2025	Percent Change
ACEC	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
AEP	$4,726,304.68	$10,138,490.06	114.5%	111,202	179,090	61.0%	$42.50	$56.61	33.2%
APS	$588,665.56	$915,734.10	55.6%	14,924	18,222	22.1%	$39.44	$50.25	27.4%
ATSI	$1,461,357.64	$3,448,199.21	136.0%	12,423	30,299	143.9%	$117.63	$113.81	(3.3%)
BGE	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
COMED	$25,624.65	$37,718.52	47.2%	793	1,005	26.7%	$32.29	$37.52	16.2%
DAY	$0.00	($4,695.51)	NA	0	0	NA	NA	NA	NA
DUKE	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
DUQ	$5,051,075.04	$9,254,085.80	83.2%	104,107	182,016	74.8%	$48.52	$50.84	4.8%
DOM	$9,330.63	$110,587.10	1,085.2%	115	428	272.5%	$81.20	$258.34	218.1%
DPL	$50,485.49	$0.00	NA	149	0	NA	$339.04	NA	NA
JCPLC	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
MEC	$23,149.54	$23,689.19	2.3%	275	251	(8.7%)	$84.24	$94.42	12.1%
OVEC	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
PECO	$32,211.59	$41,541.58	29.0%	514	615	19.8%	$62.71	$67.53	7.7%
PE	$15,295.92	$0.00	NA	119	0	NA	$128.04	NA	NA
PEPCO	$0.00	$2,406.91	NA	0	31	NA	NA	$76.55	NA
PPL	$135,388.43	$6,078.27	(95.5%)	938	26	(97.3%)	$144.29	$235.62	63.3%
PSEG	$9,071.70	$135,751.62	1,396.4%	157	1,541	879.0%	$57.63	$88.09	52.8%
REC	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
Total	$12,127,960.86	$24,109,586.85	98.8%	245,717	413,524	68.3%	$49.36	$58.30	18.1%

Table 6-40 shows average reported MWh reductions and credits by hour for 2024 and 2025. 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 2024, 69.2 percent of the reported reductions and 71.1 percent of credits occurred in hours ending 0900 EPT to 2100 EPT, and in 2025, 62.6 percent of the reported reductions and 64.5 percent of credits occurred in hours ending 0900 EPT to 2100 EPT. The average LMP during load response increased by $15.03 per MWh, 34.1 percent, from $44.08 per MWh in 2024 to $59.11 per MWh in 2025.

Table 6-40 Hourly frequency distribution of economic program reported MWh reductions and credits: 2024 and 2025

	MWh Reductions			Program Credits			Average LMP during Load Response		
Hour Ending (EPT)	2024	2025	Percent Change	2024	2025	Percent Change	2024	2025	Percent Change
1 through 6	20,649	55,334	168%	$955,291	$2,789,789	192%	$38.79	$44.48	15%
7	9,885	19,217	94%	$482,297	$1,202,514	149%	$43.81	$59.07	35%
8	12,776	20,502	60%	$766,255	$1,409,450	84%	$51.40	$67.94	32%
9	9,292	17,775	91%	$416,685	$981,820	136%	$39.23	$49.71	27%
10	9,251	15,988	73%	$384,801	$778,173	102%	$36.39	$44.88	23%
11	9,892	16,796	70%	$410,488	$827,408	102%	$36.77	$45.84	25%
12	10,569	17,020	61%	$439,727	$838,855	91%	$38.08	$45.57	20%
13	11,224	17,446	55%	$480,236	$889,529	85%	$39.06	$46.80	20%
14	11,461	17,338	51%	$516,911	$921,728	78%	$41.13	$48.68	18%
15	11,551	16,070	39%	$545,921	$808,443	48%	$43.75	$50.22	15%
16	12,238	16,489	35%	$592,336	$879,209	48%	$45.20	$54.70	21%
17	15,063	18,729	24%	$829,374	$1,101,806	33%	$51.28	$59.97	17%
18	18,363	23,756	29%	$1,163,981	$1,615,006	39%	$60.73	$73.16	20%
19	18,281	26,721	46%	$1,117,810	$1,966,463	76%	$56.50	$77.84	38%
20	17,655	28,288	60%	$1,005,177	$2,134,144	112%	$51.47	$80.65	57%
21	15,077	26,263	74%	$715,552	$1,804,057	152%	$44.18	$67.96	54%
22	13,467	23,064	71%	$587,529	$1,323,557	125%	$40.59	$54.66	35%
23 through 24	19,025	36,727	93%	$717,590	$1,837,636	156%	$35.05	$91.86	162%
Total	245,717	413,524	68%	$12,127,961	$24,109,587	99%	$44.08	$59.11	35%

Table 6-41 shows the distribution of economic program reported MWh reductions and credits by ranges of real-time zonal load-weighted average LMP in 2024 and 2025. In 2025, 2.1 percent of reported MWh reductions and 8.5 percent of program credits occurred during hours when the applicable zonal LMP was higher than $175 per MWh.

Table 6-41 Frequency distribution of economic program zonal load-weighted average LMP (By hours): 2024 and 2025

	MWh Reductions			Program Credits		
LMP	2024	2025	Percent Change	2024	2025	Percent Change
$0 to $25	16,779	430	(97%)	$369,709	$7,849	(98%)
$25 to $50	154,562	229,652	49%	$5,666,335	$8,857,319	56%
$50 to $75	43,888	110,611	152%	$2,618,252	$6,690,347	156%
$75 to $100	11,942	37,119	211%	$1,006,037	$3,188,825	217%
$100 to $125	7,032	16,504	135%	$759,070	$1,841,566	143%
$125 to $150	7,235	7,135	(1%)	$948,564	$924,385	(3%)
$150 to $175	2,658	3,413	28%	$400,729	$538,172	34%
> $175	1,621	8,658	434%	$359,264	$2,061,124	474%
Total	245,717	413,524	68%	$12,127,961	$24,109,587	99%

Economic Load Response revenues are paid by real-time loads and real-time scheduled exports as an uplift charge. Table 6-42 shows the sum of real-time and day-ahead Economic Load Response charges paid in each zone and paid by exports. In 2025, AEP Zone has paid the highest Economic Load Response charges.

Table 6-42 Zonal Economic Load Response charge: 2025[115]

Zone	January	February	March	April	May	June	July	August	September	October	November	December	Total
AECO	$48,626	$32,112	$23,398	$17,662	$11,557	$24,253	$39,658	$14,389	$11,944	$18,438	$8,499	$1,954	$252,490
AEP	$742,329	$489,401	$402,850	$404,409	$184,147	$330,974	$404,437	$195,906	$194,407	$303,170	$147,565	$31,246	$3,830,841
APS	$296,622	$191,496	$160,016	$146,619	$67,944	$117,406	$146,245	$66,719	$63,848	$101,533	$54,957	$11,489	$1,424,893
ATSI	$341,093	$237,093	$210,668	$205,714	$83,847	$167,016	$210,489	$95,567	$91,919	$142,925	$67,587	$14,093	$1,868,010
BGE	$185,335	$118,543	$98,599	$98,175	$49,790	$80,819	$102,474	$43,223	$41,484	$59,612	$33,101	$6,886	$918,043
COMED	$336,266	$292,798	$152,468	$139,964	$105,832	$241,087	$309,379	$148,724	$133,531	$149,535	$78,027	$15,758	$2,103,370
DAY	$95,107	$64,474	$53,070	$55,452	$26,975	$44,780	$56,183	$27,381	$25,767	$37,762	$18,324	$3,818	$509,091
DUKE	$144,143	$95,862	$76,538	$79,483	$36,708	$70,017	$86,783	$40,813	$38,661	$54,055	$26,414	$5,548	$755,025
DUQ	$66,568	$44,192	$38,251	$37,367	$15,491	$34,361	$43,916	$19,844	$18,214	$26,396	$12,415	$4,338	$361,355
DOM	$730,501	$478,676	$413,741	$443,278	$220,167	$337,845	$404,527	$180,678	$181,341	$280,088	$145,997	$2,645	$3,819,484
DPL	$113,836	$73,521	$46,255	$33,822	$20,898	$39,464	$63,664	$24,198	$21,487	$33,634	$17,101	$30,169	$518,050
EKPC	$101,608	$62,099	$43,140	$38,740	$18,299	$33,921	$42,573	$20,431	$19,295	$28,605	$15,682	$3,538	$427,932
JCPLC	$110,394	$74,496	$60,250	$43,258	$26,585	$57,157	$86,051	$31,412	$26,502	$41,678	$18,923	$3,344	$580,050
MEC	$84,800	$56,750	$47,100	$33,533	$24,718	$35,271	$46,595	$18,316	$14,557	$27,076	$12,997	$27	$401,739
OVEC	$579	$454	$382	$354	$138	$202	$256	$122	$125	$228	$127	$8,346	$11,312
PECO	$210,523	$139,657	$91,232	$62,260	$43,003	$79,060	$126,075	$48,676	$45,127	$71,457	$34,530	$3,604	$955,204
PE	$90,525	$64,985	$55,621	$49,016	$22,826	$39,300	$48,214	$21,551	$21,026	$35,633	$17,883	$6,324	$472,903
PEPCO	$168,433	$107,854	$89,877	$88,324	$48,903	$75,620	$94,649	$38,996	$38,898	$55,348	$29,374	$8,903	$845,179
PPL	$237,574	$155,164	$120,527	$88,201	$45,933	$83,762	$118,999	$43,700	$35,616	$72,472	$34,918	$8,911	$1,045,776
PSEG	$209,242	$145,350	$117,250	$85,072	$52,679	$105,954	$152,555	$58,218	$52,956	$82,974	$37,673	$276	$1,100,200
REC	$6,462	$4,591	$4,059	$2,990	$1,884	$4,253	$5,737	$2,263	$1,985	$2,879	$1,310	$10,717	$49,130
Exports	$310,870	$222,254	$197,109	$344,947	$190,689	$126,905	$157,377	$95,419	$69,350	$84,938	$55,109	$4,541	$1,859,510
Total	$4,631,435	$3,151,821	$2,502,401	$2,498,640	$1,299,013	$2,129,425	$2,746,837	$1,236,546	$1,148,040	$1,710,438	$868,515	$186,476	$24,109,587

115 Load response charges were downloaded as of January 13, 2026, and may change as a result of continued PJM billing updates.

Table 6-43 shows the total zonal Economic Load Response charge per GWh of real-time load and exports in 2025.[116]

Table 6-43 Zonal economic load response charge per GWh of load and exports: 2025

Zone	January	February	March	April	May	June	July	August	September	October	November	December	Zonal Average
AECO	$0.055	$0.045	$0.035	$0.028	$0.017	$0.026	$0.032	$0.015	$0.015	$0.028	$0.013	$0.006	$0.026
AEP	$0.056	$0.045	$0.038	$0.041	$0.018	$0.028	$0.031	$0.016	$0.018	$0.028	$0.013	$0.006	$0.028
APS	$0.057	$0.045	$0.041	$0.041	$0.019	$0.029	$0.031	$0.016	$0.018	$0.028	$0.014	$0.006	$0.029
ATSI	$0.055	$0.043	$0.040	$0.042	$0.017	$0.028	$0.031	$0.016	$0.018	$0.028	$0.013	$0.006	$0.028
BGE	$0.058	$0.046	$0.043	$0.048	$0.023	$0.030	$0.032	$0.017	$0.018	$0.029	$0.015	$0.006	$0.030
COMED	$0.040	$0.040	$0.022	$0.021	$0.016	$0.028	$0.031	$0.016	$0.018	$0.021	$0.011	$0.005	$0.022
DAY	$0.056	$0.045	$0.039	$0.044	$0.021	$0.029	$0.032	$0.017	$0.019	$0.028	$0.014	$0.006	$0.029
DUKE	$0.056	$0.045	$0.038	$0.042	$0.019	$0.029	$0.031	$0.017	$0.018	$0.028	$0.013	$0.006	$0.029
DUQ	$0.054	$0.043	$0.038	$0.041	$0.016	$0.029	$0.031	$0.016	$0.018	$0.028	$0.013	$0.006	$0.028
DOM	$0.057	$0.046	$0.042	$0.047	$0.022	$0.029	$0.031	$0.016	$0.017	$0.029	$0.014	$0.006	$0.030
DPL	$0.057	$0.047	$0.033	$0.027	$0.016	$0.024	$0.032	$0.015	$0.015	$0.027	$0.013	$0.006	$0.026
EKPC	$0.061	$0.049	$0.040	$0.042	$0.019	$0.029	$0.032	$0.017	$0.019	$0.028	$0.014	$0.006	$0.030
JCPLC	$0.055	$0.044	$0.039	$0.030	$0.017	$0.028	$0.033	$0.015	$0.016	$0.028	$0.012	$0.006	$0.027
MEC	$0.056	$0.044	$0.040	$0.031	$0.023	$0.027	$0.031	$0.014	$0.013	$0.025	$0.011	$0.006	$0.027
OVEC	$0.048	$0.043	$0.037	$0.039	$0.016	$0.025	$0.028	$0.014	$0.016	$0.027	$0.013	$0.006	$0.026
PECO	$0.056	$0.044	$0.031	$0.023	$0.016	$0.023	$0.031	$0.014	$0.015	$0.027	$0.012	$0.006	$0.025
PE	$0.056	$0.046	$0.042	$0.040	$0.019	$0.029	$0.031	$0.016	$0.018	$0.028	$0.014	$0.006	$0.029
PEPCO	$0.058	$0.047	$0.043	$0.046	$0.024	$0.030	$0.032	$0.016	$0.018	$0.028	$0.015	$0.006	$0.030
PPL	$0.056	$0.043	$0.037	$0.030	$0.016	$0.025	$0.030	$0.013	$0.012	$0.025	$0.011	$0.006	$0.025
PSEG	$0.055	$0.045	$0.038	$0.029	$0.017	$0.027	$0.032	$0.015	$0.016	$0.027	$0.012	$0.006	$0.027
REC	$0.054	$0.045	$0.040	$0.031	$0.018	$0.031	$0.033	$0.016	$0.017	$0.028	$0.013	$0.006	$0.028
Exports	$0.063	$0.051	$0.044	$0.098	$0.046	$0.027	$0.029	$0.016	$0.015	$0.029	$0.016	$0.006	$0.037
Monthly Average	$0.056	$0.045	$0.038	$0.039	$0.020	$0.028	$0.031	$0.016	$0.017	$0.027	$0.013	$0.006	$0.028

Table 6-44 shows the monthly day-ahead and real-time Economic Load Response charges for 2024 and 2025. The day-ahead Economic Load Response charges increased by $12.1 million, 101.6 percent, from $11.9 million in 2024 to $23.9 million in 2025. The real-time Economic Load Response charges decreased $0.1 million, 0.1 percent, from $0.3 million in 2024 to $0.2 million in 2025.[117]

Table 6-44 Monthly day-ahead and real-time economic load response charge: 2024 and 2025

	Day-ahead Economic Load Response Charge			Real-time Economic Load Response Charge		
Month	2024	2025	Percent Change	2024	2025	Percent Change
Jan	$2,598,194	$4,606,508	77.3%	$23,442	$24,927	6.3%
Feb	$63,832	$3,044,896	4,670.2%	$3,723	$106,925	2,772.1%
Mar	$75,020	$2,490,135	3,219.3%	$586	$12,266	1,993.7%
Apr	$101,710	$2,490,770	2,348.9%	$2,021	$7,870	289.5%
May	$933,721	$1,292,724	38.4%	$2,473	$6,289	154.4%
Jun	$522,354	$2,126,584	307.1%	$28,167	$2,841	(89.9%)
Jul	$1,285,277	$2,742,529	113.4%	$148,484	$4,308	(97.1%)
Aug	$1,373,099	$1,233,542	(10.2%)	$32,880	$3,005	(90.9%)
Sep	$1,547,072	$1,145,640	(25.9%)	$6,724	$2,399	(64.3%)
Oct	$1,633,066	$1,707,983	4.6%	$3,796	$2,455	(35.3%)
Nov	$721,478	$868,825	20.4%	$932	($310)	(133.2%)
Dec	$1,015,836	$186,476	(81.6%)	$4,075	$0	(100.0%)
Total (Jan-Dec)	$11,870,659	$23,936,612	101.6%	$257,302	$172,975	(32.8%)

Table 6-45 shows registered sites and MW for the last day of each month for the period January 1, 2021, through December 31, 2025. Registration is a prerequisite for CSPs to participate in the economic program. Average monthly registrations increased by 70, 13.6 percent, from 511 in 2024 to 581 in 2025. Average monthly registered MW increased by 49 MW, 1.6 percent, from 3,106 MW in 2024 to 3,155 MW in 2025.

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 174 economic registrations

116 Load response charges were downloaded as of January 13, 2026, and may change as a result of continued PJM billing updates.

117 Load response charges were downloaded as of January 13, 2026, and may change as a result of continued PJM billing updates. Economic demand response reductions that are submitted to PJM for payment but have not received payment are not included. Payments for Economic demand response reductions are settled monthly.

and 182 capacity registrations in the emergency program that share the same location IDs in both programs. There are 1,450.6 nominated economic MW, 46.0 percent of all economic MW and 1,282.0 nominated capacity MW, 16.0 percent of all nominated capacity MW in the emergency program that share the same location IDs in both programs.

Table 6-45 Economic program registrations on the last day of the month: 2021 through 2025[118]

	2021		2022		2023		2024		2025	
Month	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW
Jan	277	1,495	323	2,233	347	2,874	462	3,176	563	2,981
Feb	275	1,503	323	2,256	354	2,870	472	3,299	576	3,013
Mar	284	1,514	330	2,377	361	2,930	476	3,244	587	3,166
Apr	293	1,538	330	2,382	373	2,932	481	3,207	580	3,157
May	319	1,658	326	2,377	378	3,006	487	3,230	585	3,275
Jun	313	2,136	315	2,323	396	2,929	501	2,942	581	3,147
Jul	312	2,105	310	2,412	412	3,096	524	3,266	581	3,139
Aug	322	2,122	318	2,451	428	3,163	528	3,027	576	3,157
Sep	322	2,256	329	2,565	440	3,335	531	3,017	582	3,246
Oct	332	2,267	333	2,575	453	3,362	543	2,922	597	3,260
Nov	333	2,270	338	2,593	478	3,499	560	2,948	586	3,223
Dec	320	2,256	359	2,640	487	3,493	570	2,989	576	3,095
Avg	309	1,927	328	2,432	409	3,124	511	3,106	581	3,155

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 6-46 shows the sum of maximum economic MW dispatched by registration each month from January 1, 2013, through December 31, 2025. 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 increased 50.8 MW, 21.1 percent, in 2025 compared to 2024.[119]

Table 6-46 Sum of maximum MW reported reductions for all registrations per month: 2013 through 2025

	Sum of Peak MW Reductions for all Registrations per Month												
Month	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Jan	193	446	169	139	123	142	88	28	21	34	50	281	404
Feb	119	307	336	128	83	70	58	11	86	34	18	102	409
Mar	127	369	198	120	111	71	38	12	20	30	53	102	271
Apr	133	146	143	118	54	71	41	3	22	43	70	84	245
May	192	151	161	131	169	70	22	12	9	53	141	247	152
Jun	433	483	833	121	240	105	26	38	125	110	96	213	342
Jul	1,088	665	1,362	1,316	936	518	770	135	134	150	309	469	370
Aug	497	358	272	249	141	581	33	99	827	162	191	376	198
Sep	530	795	816	263	140	112	76	31	35	88	392	223	281
Oct	168	214	136	150	88	69	29	9	31	67	80	344	337
Nov	155	166	127	116	81	54	35	12	31	58	88	138	289
Dec	168	155	122	147	83	11	31	14	19	116	77	315	205
Annual	1,486	1,739	1,858	1,451	1,217	758	830	196	921	263	735	616	688

Table 6-47 shows total settlements submitted for 2013 through 2025. A settlement is counted for every day on which a registration is dispatched in the economic program.

Table 6-47 Settlements submitted in the economic program: 2013 through 2025

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Number of Settlements	2,846	3,014	2,173	1,958	1,884	1,524	1,066	520	931	1,793	870	2,016	3,938

118 Data for years 2010 through 2017 are available in the *2017 Annual State of the Market Report for PJM.*
119 Maximum MW reductions were downloaded as of January 13, 2026, and may change as a result of continued PJM billing updates.

Table 6-48 shows the number of CSPs, and the number of participants in their portfolios, submitting settlements for 2013 through 2025. The number of active participants increased by 14, 31.8 percent, from 44 in 2024 to 58 in 2025. All participants must be registered through a CSP.

Table 6-48 Participants and CSPs submitting settlements in the economic program by year: 2013 through 2025

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Active CSPs	20	18	18	12	13	14	13	11	11	9	8	6	5
Active Participants	276	165	116	58	72	59	53	29	37	31	32	44	58

Issues

FERC Order No. 831 requires that each RTO/ISO market monitoring unit verify all energy offers above $1,000 per MWh.[120] 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."[121] 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.[122] 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

120 157 FERC ¶ 61,115 at P 139 (2016).
121 *Id.* at 8.
122 "PJM Manual 11: Energy & Ancillary Services Market Operations," §10.3.1, Rev. 136 (October 1, 2025)

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.[123]

Table 6-49 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 December 2025. 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 2025, the NBT threshold price did not exceed the lowest historical test result of $34.07 per MWh.

Table 6-49 Net benefits test threshold prices: August 2010 through December 2025

	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
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
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
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
Apr	$38.07	$36.76	$27.92	$27.94	$32.59	$24.92	$19.93	$30.45	$25.56	$22.36	$15.91	$23.47	$35.14	$23.68	$17.17	$30.31
May	$35.82	$34.68	$23.46	$27.73	$32.08	$23.71	$20.69	$29.65	$25.52	$21.01	$14.69	$21.40	$42.94	$23.43	$16.82	$27.76
Jun	$36.12	$35.09	$23.86	$28.44	$31.62	$23.80	$20.62	$27.14	$23.59	$20.20	$15.56	$22.35	$44.29	$22.33	$18.41	$22.48
Jul	$37.68	$27.92	$22.99	$29.42	$31.62	$23.03	$20.73	$24.42	$23.57	$19.76	$14.66	$21.59	$48.67	$22.66	$21.15	$25.54
Aug	$35.57	$33.86	$24.47	$28.58	$29.85	$23.17	$23.24	$22.75	$23.53	$19.57	$14.58	$20.52	$44.08	$24.89	$17.48	$25.38
Sep	$34.07	$31.07	$24.33	$28.80	$29.83	$21.69	$24.70	$21.51	$22.23	$18.19	$15.16	$23.06	$55.39	$25.04	$14.71	$20.92
Oct	$38.10		$25.96	$29.13	$30.20	$21.48	$26.50	$21.70	$23.84	$20.20	$17.25	$24.24	$55.97	$21.73	$14.22	$22.20
Nov	$36.83		$25.63	$31.63	$29.17	$22.28	$29.27	$26.41	$23.89	$21.11	$18.35	$29.20	$49.57	$23.12	$19.81	$28.34
Dec	$37.04		$25.97	$28.82	$29.01	$22.31	$29.71	$29.16	$26.35	$22.24	$19.47	$32.85	$42.75	$24.43	$20.13	$31.56
Average	$37.60	$35.60	$25.30	$28.10	$30.95	$23.96	$23.99	$27.33	$24.54	$21.64	$16.87	$23.03	$42.53	$25.42	$18.45	$25.87

Table 6-50 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.[124] In 2025, the highest zonal LMP in PJM was higher than the NBT threshold price 8,307 hours out of 8,760 hours, or 94.8 percent of all hours. Reductions occurred in 7,348 hours, 88.5 percent, of those 8,307 hours in 2025. The last three columns illustrate how often economic demand response activity occurred when LMPs exceeded NBT threshold prices for January 1, 2024, through December 31, 2025. 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 2024, and none of the hours in which LMP was below the NBT threshold price in 2025.

123 "PJM Manual 11: Energy & Ancillary Services Market Operations," §10.3.4, Rev. 136 (October 1, 2025)
124 The MWh for demand resources were downloaded as of January 13, 2026, and may change as a result of continued PJM billing updates.

Table 6-50 Hours with price higher than NBT and economic load response occurrences in those hours: 2024 and 2025

	Number of Hours		Number of Hours with LMP Higher than NBT			Percent of NBT Hours with Economic Load Response		
Month	2024	2025	2024	2025	Percent Change	2024	2025	Percentage Change
Jan	744	744	732	737	0.7%	51.6%	97.4%	45.8%
Feb	696	672	568	672	18.3%	31.5%	95.5%	64.0%
Mar	743	743	618	742	20.1%	27.7%	97.7%	70.0%
Apr	720	720	700	662	(5.4%)	37.0%	94.7%	57.7%
May	744	744	723	580	(19.8%)	64.3%	82.4%	18.1%
Jun	720	720	610	685	12.3%	65.9%	77.2%	11.3%
Jul	744	744	636	718	12.9%	87.6%	91.8%	4.2%
Aug	744	744	670	603	(10.0%)	85.4%	78.4%	(6.9%)
Sep	720	720	694	708	2.0%	81.7%	74.6%	(7.1%)
Oct	744	744	744	744	0.0%	96.8%	99.1%	2.3%
Nov	721	721	669	721	7.8%	92.5%	96.9%	4.4%
Dec	744	744	728	735	1.0%	87.5%	72.5%	(15.0%)
Total	8,784	8,760	8,092	8,307	2.7%	68.3%	88.5%	20.2%

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.[125] Payments from PJM customers to energy efficiency providers are a subsidy and uplift. The rules described here remain in effect until June 1, 2026.

The MMU had long recommended that Energy Efficiency Resources (EE) be removed from the capacity market mechanism because PJM's load forecasts now account for EE, unlike the situation when EE was first added to the capacity market.[126] EE should not be part of the capacity market mechanism in any way. EE is appropriately and automatically compensated through the markets because to the extent that it actually reduces energy and capacity use, it reduces customer payments for energy and capacity. EE is appropriately incorporated in PJM forecasts, so the original logic for the inclusion of EE in the capacity market is no longer correct.

History

EE is not a capacity resource and is not treated as a capacity resource in the capacity market. EE does not contribute to meeting the RPM Reliability Requirement. EE resources may not serve as a replacement for the commitment of any other RPM Capacity Resource type.

On March 26, 2009, FERC approved Tariff and RAA changes to allow EE Resources to participate in PJM Capacity Markets beginning with the Base Residual Auction conducted in May 2009 which committed capacity for the 2012/2013 Delivery Year.[127] FERC approved PJM's request to allow EE Resource participation beginning June 1, 2011, in the remaining 2011/2012 Incremental Auctions by letter order dated January 22, 2010 in Docket No. ER10-366-000. The only reason that EE was included in the capacity market in the first place was that EE was asserted to not be included in the PJM load forecast used in the capacity market. PJM stated that EE was not fully reflected in the load forecast for four years based on the method in place at the time.

Revisions to the PJM load forecast to incorporate energy efficiency were endorsed at the November 19, 2015, MRC.[128] These revisions included improvements to comprehensively capture energy efficiency impacts through incorporation of projections from the U.S. Energy Information Administration (EIA) Annual Energy Outlook (AEO). The AEO forecast is based on a set of end use models for the residential, commercial, and industrial sectors. EIA accounts for state and utility efficiency programs by mapping regional EE program expenditures to end uses and tracks the number of

125 See 189 FERC ¶ 61,095, *reh'g denied*, 190 FERC ¶ 62,005 (2025).
126 "PJM Manual 19: Load Forecasting and Analysis," § 3.2 Development of the Forecast, Rev. 38 (Dec. 17, 2025).
127 126 FERC ¶ 61,275 (2009).
128 See *Approved Minutes from the Markets and Reliability Committee*, <https://www.pjm.com/-/media/committees-groups/committees/mrc/20151217/20151217-item-01-draft-minutes-20151119.ashx> (December 17, 2015).

units sold and associated efficiency information on an ongoing basis.[129]

As soon as PJM explicitly included EE in the load forecast used in the capacity market, PJM should have followed its tariff language and logic and eliminated EE from the capacity market construct entirely. Instead of eliminating EE from the capacity market construct consistent with the tariff and logic, PJM removed EE from capacity resource status and implemented a calculation method (misleadingly termed the addback method) that would pay EE the capacity market clearing price while having no impact, either price or quantity, on the capacity market. Beginning with capacity auctions conducted in 2016 for the 2016/2017 through 2025/2026 Delivery Years, PJM paid EE the capacity market clearing price while completely excluding EE from the actual capacity market. Use of this approach to EE addback did inappropriately require that customers pay for all EE offered at less than the market clearing price as an uplift payment or subsidy to EE sellers.

After the MMU filed a complaint in Docket No. EL24-126 requesting that the Commission require PJM to stop paying EE the uplift/subsidy, PJM filed to confirm removal of the EE from the capacity market construct, including the subsidy. On November 5, 2024, the Commission approved the complete removal of EE effective with the 2026/2027 capacity auction.[130] The MMU subsequently noticed withdrawal of the MMU complaint.[131]

Prior to the MMU complaint filed in Docket No. EL24-126, the MMU filed a complaint in Docket No. EL24-113 against indicated EE sellers for failure to submit post-installation M&V reports sufficient to support payments for EE from PJM for the 2024/2025 Delivery Year.[132] The complaint remains pending.

On May 29, 2025, in Docket No. EL25-87-000, the MMU filed a second complaint against indicated EE sellers who are providers of Energy Efficiency Resources for the 2025/2026 Delivery Year. The complaint alleges that the sellers' post-installation measurement and verification reports for the 2025/2026 Delivery Year are inadequate and capacity payments should be withheld pending further review.[133] The complaint remains pending.

PJM stakeholders initiated a holistic review of Energy Efficiency Resources participation in PJM markets in November of 2023. A sector-weighted super majority of PJM's stakeholders supported elimination of EE from the capacity construct at the MRC and the MC meetings on August 21, 2024.[134] PJM filed the proposal under Section 205 on September 6, 2024.[135] On November 5, 2024, the Commission issued an order approving the proposed Tariff and RAA revisions to remove Energy Efficiency Resource participation from the PJM capacity construct effective with the 2026/2027 Delivery Year.[136] On December 5, 2024, Affirmed Energy LLC filed a motion of a stay and a request for rehearing. An order denying rehearing by operation of law was issued January 6, 2025.[137] On February 7, 2025, the Commission issued an order denying the motion for stay and affirming its earlier denial of rehearing.[138]

On December 16, 2024, the Commission issued an Order to Show Cause and Notice of Proposed Penalty recommending civil penalties against American Efficient, LLC, a large seller of EE, and its affiliates in connection with an alleged scheme to manipulate the capacity markets operated by PJM and MISO.[139] The Order directs American Efficient to show cause as to why it should not be required to pay a civil penalty of $722 million and disgorge $253 million in unjust profits. On January 29, 2025, American Efficient, et al. filed for review of the show cause order in the United States District Court for the Middle District of North Carolina.[140] The court case is pending.

EE Details

In addition to the fact that EE resources are not capacity resources, the measurement of EE that was required as a condition to receive subsidy payments from PJM were largely unsupported by factual evidence or actual measurements.

An EE Resource is required to be a project that involves the installation of more efficient devices or

129 See EIA. Analysis of Energy Efficiency Program Impacts Based on Program Spending<https://www.eia.gov/analysis/studies/buildings/efficiencyimpacts/pdf/programspending.pdf> (Accessed January 18, 2024).
130 See 189 FERC ¶ 61,095, *reh'g denied*, 190 FERC ¶ 62,005 (2025).
131 See Complaint of the Independent Market Monitor for PJM, Docket No. EL24-126-000 (July 10, 2024), Notice of Withdrawal of Complaint, Docket No. EL24-126-000 (November 19. 2024); RAA Schedule 6 § L.1, OATT Attachment DD-1 § L.1.
132 See Complaint of the Independent Market Monitor for PJM, Docket No. EL24-113-000 (May 31, 2024).
133 See Complaint of the Independent Market Monitor for PJM, Docket No. EL25-87 (May 29, 2025).
134 PJM Transmittal Letter, Docket No. ER24-2995 at 41 (Sept. 6, 2024).
135 PJM Interconnection, L.L.C., Docket No. ER24-2995-000, Proposal to Enable Energy Efficiency to Benefit Loads Through Demand-Side Reduction to the Peak Load Forecast and Savings from Energy Market Charges (Sept. 6, 2024)
136 See 189 FERC ¶ 61,095.
137 See 190 FERC ¶ 62,005.
138 See 190 FERC ¶ 61,081.
139 See 189 FERC ¶ 61,196.
140 See American Efficient, LLC, et al. v. FERC, Case No. 1:25-cv-68.

equipment, or the implementation of more efficient processes or systems, exceeding then current building codes, appliance standards, or other relevant standards, at the time of installation, as known at the time of commitment, and meets the requirements of Schedule 6 (section L) of the Reliability Assurance Agreement. The EE Resource must achieve a permanent, continuous reduction in electric energy consumption at the End Use Customer's retail site during the defined EE Performance Hours that is not reflected in the peak load forecast used for the auction delivery year for which the EE Resource is proposed.[141]

Despite the fact that the EE Resource must be fully implemented at all times during the delivery year, without any requirement of notice, dispatch, or operator intervention, EE accreditation is based only on extremely limited periods. EE is required to demonstrate savings only during three summer months and two winter months and only for extremely limited hours during those months. The EE Performance Hours in the summer are defined as the four hours from the hour ending 15:00 Eastern Prevailing Time (EPT) through the hour ending 18:00 EPT during all days for the three month period from June 1 through August 31, inclusive, of such delivery year, that is not a weekend or federal holiday. For the 2023/2024 Delivery Year, the summer EE Performance hours comprise 256 hours across 64 days. The EE Performance Hours in the winter are defined as the four hours from the hour ending 8:00 EPT and hour ending 9:00 EPT, and from the hour ending 19:00 EPT and hour ending 20:00 EPT during all days for the two month period from January 1 through February 28, inclusive, of such delivery year that is not a weekend or federal holiday, For the 2023/2024 Delivery Year, the winter EE Performance hours comprise 160 hours across 40 days. For the 2023/2024 Delivery Year, the total annual EE Performance hours comprised 416 hours across 104 days, or 4.7 percent of all hours in the year.

141 See RAA Schedule 6 § L. Since 2010, the PJM tariff definition of "End User Customer" limits the scope of the term to mean only PJM Members. Letter Order, Docket No. ER11-1909-000 (December 20, 2010). Recently, PJM 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 defined term was in place for more than 13 years and subject to many reviews. The proposed change removes the current requirement in the filed tariff that EE loads be End Use Customers and therefore be PJM Members. The proposed change is substantive and not a correction of a typographical error. PJM has been operating in violation of that tariff provision since 2010. The proposed change was filed and approved. *PJM Interconnection, L.L.C.*, Letter Order, Docket No. ER24-1987-000 (May 23, 2024).

Calculating the Nominated MW value for Energy Efficiency (EE) resources is different than calculating the Nominated MW value for actual capacity resources. The maximum amount of Nominated MW a generator can offer into the capacity market is based on the maximum output of a generator that is metered and tested. The Nominated MW for EE resources are not metered or measured or tested, although they could be, but are based on calculations of estimated savings based on a set of largely unverified and unverifiable assumptions. The Nominated Value of an EE Resource is the expected average demand reduction during the summer EE Performance Hours. Qualifying EE Resources must also have an expected average load reduction during the winter EE performance hours that is not less than the Nominated EE Value determine during the summer EE Performance Hours. If the Nominated EE Value determined during the summer EE Performance Hours is greater than the expected average demand during the winter performance hours, the expected demand during the winter performance hours will be the value of the EE Resource. The Nominated EE Value of a Summer-Period Energy Efficiency Resource is the expected average demand reduction during the summer EE Performance Hours.

Prescriptive energy efficiency MW are based on and paid on assumed savings calculated based on an assumed installation rate and on the difference between the assumed electricity usage of what is being replaced and the assumed electricity usage of the new product. All lighting EE is prescriptive. The majority of EE MW offered into the PJM Capacity Market are prescriptive energy efficiency MW. The measurement and verification method for prescriptive energy efficiency projects relies on neither measurement nor verification but instead relies on unverified assumptions and is too imprecise to rely on for the payment of more than $100 million per year. The nonprescriptive measurement and verification methods are also inadequate and rely on samples and assumptions for limited periods that are frequently significantly outdated.[142]

142 PJM. "Manual 18B: Energy Efficiency Measurement & Verification," § 2.2 Rev. 05 (Sep. 21, 2022).

Most EE MW are not directly measured. Savings are calculated based on an assumed installation rate and assumed usage level, compared to the assumed electricity usage of the default. For example, the calculation of the summer period lighting savings for a residential lighting retrofit is generally:

*ΔkW = ((WattsBase - WattsEE) /1000) * ISR * WHFd * CF*

Where:

ISR = In Service Rate approximating percent of bulbs installed in calculation year

WHFd = Waste Heat Factor for Demand to account for cooling savings from efficient lighting

CF = Summer Peak Coincidence Factor approximating percent of EE Performance Hours device is in use

The inputs to these calculations are based on assumptions and observations over very limited periods and generally rely on data that is significantly out of date. Many EE Providers rely on usage assumptions from industry publications rather than from primary data collected from measurements of their own customers. A commonly referenced document in supporting Measurement & Verification reports is the Maryland/Mid-Atlantic Technical Reference Manual (TRM) facilitated and managed by Northeast Energy Efficiency Partnerships, a 501 (c)(3) non-profit organization funded by various advocacy groups and the federal government.[143] [144] While this manual focuses on a geographic region included in PJM's service territory, EE Providers can and do use assumptions based on installations in locations outside of PJM's service territory. The technical reference manuals (TRM) referenced by EE Providers are generally significantly outdated and therefore cannot reasonably be used to define the actual current baseline conditions that should be used for valuation of projects. Given the development cycle, the data underlying the TRM lags the publishing date by several years. Of TRMs frequently referenced by EE Providers, the Maryland/Mid-Atlantic TRM was published in 2020, the Pennsylvania TRM in 2024 and the Ohio TRM in 2019. The Pennsylvania PUC updates and approves its TRM on a 5-year cycle.[145] As a result, for the normal three year capacity market timing, a three year old TRM, relying on data from as much as five years prior to publication, is used to estimate savings for at least four years into the future. As a result, in the fourth year of the EE resource, its purported savings will be based on data from 15 years earlier. That is not a reasonable basis for calculating savings. Table 6-51 shows the current publishing dates of TRMs frequently referenced in M&V reporting submitted to PJM. In addition to Technical Reference Manuals, other studies and references are cited in EE M&V Plans and Reports. These citations are likewise used to justify the claimed benefits and savings attributed to Energy Efficiency projects. These materials, as with the TRMs, are often several years out of date and commonly 10 years old and in some cases older.

Table 6-51 Publishing dates (Year) of technical resource manuals

State/Region	Current Version
Delaware	2016
Illinois	2024
Maryland	2020
New Jersey	2023
Ohio	2019
Pennsylvania	2024
Tennessee	2015
Mid-Atlantic	2020

Another weakness of the methods used to evaluate EE is the failure to recognize that the incremental benefits of EE measures decline over time as improved energy saving technology is adopted by customers. This improvement in technology reduces the baseline energy usage against which incremental savings should be measured. An example of a decreasing baseline in energy usage is in residential lighting. The assumed baseline condition was originally an incandescent bulb but should have evolved to more and more efficient LEDs, which eliminates the incremental savings when replaced by another LED lightbulb.

The mix of EE project types offered should have more quickly reflected the actual technology adopted in the markets. In the 2019/2020 BRA, lighting projects comprised 77 percent of all EE measures. Table 6-52 shows the composition of project types submitted in M&V Plans for the 2019/2020 RPM Base Residual Auction.

143 See *Maryland/Mid-Atlantic Technical Reference Manual Version 10* <https://neep.org/mid-atlantic-technical-reference-manual-trm-v10> (May 27, 2020).
144 See *Northeast Energy Efficiency Partnership* <https://neep.org/> (March 4, 2024)
145 66 PA § 2806.1(c)(3)

Table 6-52 EE Project Types – 2019/2020 Delivery Year

Project Type	2019/2020
Residential Lighting	23%
Residential HVAC	1%
Residential New Construction	<1%
Appliances	<1%
Commercial Lighting	54%
Commercial Prescriptive	8%
Commercial HVAC	<1%
Small Business	4%
Commercial Construction	2%
Other	7%

In the 2024/2025 BRA, lighting dropped to 45 percent of all EE measures. Building envelope measures, which include thermal performance improvements to exterior walls, windows, doors, and roofing to reduce building energy consumption were a growing project type encompassing 33 percent of all EE measures in the 2024/2025 BRA. Table 6-53 shows the composition of project types submitted in EE M&V Plans for the 2024/2025 RPM Base Residual Auction.

Table 6-53 EE Project Types – 2024/2025 Delivery Year

Project Type	2024/2025
Lighting	45%
Building Envelope	33%
Variable Frequency Drives	8%
Appliances	<1%
Other	14%

There is no evidence that the EE programs result in changed behavior or increases in savings. EE Providers may repackage the independent actions of customers that have already occurred. There is no evidence that EE participation in PJM markets causes End Use Customers to reduce their energy consumption beyond what they would have otherwise.

While EE does not affect the capacity market clearing price or quantity, customers do pay for EE at capacity market clearing prices. These direct payments to EE are a subsidy and uplift and an overpayment by customers. Table 6-54 shows the RPM revenues paid, by delivery year, to energy efficiency (EE) resources in PJM.

PJM does not codify eligibility requirements to claim the property rights to energy efficiency installations in the tariff. PJM does not have a registration system to track claims to property rights to energy efficiency installations and document installation periods of energy efficiency installations. The purpose of the registration system is to prevent duplicative claims to property rights and to document installation periods of energy efficiency to verify eligibility for continued participation measures. Energy Efficiency projects should be clearly identified by retail customer account, year of project installation and a description of the Energy Efficiency project.

A registration system would also serve the benefit of preventing multiple Energy Efficiency Providers from claiming property rights to the same project. The Energy Efficiency Resource Provider offering an Energy Efficiency Resource for payment must demonstrate to PJM that it has the legal authority to claim the demand associated with such Energy Efficiency Resource.[146] This demonstration is generally a prepackaged statement, provided by PJM, that is never fully verified. PJM should have codified eligibility requirements to claim the property rights to Energy Efficiency installations in the Tariff. These eligibility requirements should specifically define the conditions under which an Energy Efficiency Resource Provider may claim the property rights to Energy Efficiency installations as well as evidentiary requirements such as signed contracts with their customers conferring such rights. PJM does not require contracts between the seller of EE to PJM and the actual owner of the EE. It is not always clear who the owner of the EE property rights actually is.

Table 6-54 shows the amount of energy efficiency (EE) resources paid as of June 1 for the 2011/2012 through 2025/2026 Delivery Years. EE resources may participate in PJM without restrictions imposed by a state unless the Commission authorizes a state to impose restrictions.[147] Only Kentucky has been so authorized by the Commission.[148] The total MW of energy efficiency resources paid decreased by 80.6 percent, from 7,716.0 MW in the 2024/2025 Delivery Year to 1,493.2 MW in the 2025/2026 Delivery Year.

146 EE Post-Installation Measurement & Verification Report Template, <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/post-installation-measurement-and-verification.ashx> *(Accessed Aug. 5, 2022).*

147 See 161 FERC ¶ 61,245 at P 57 (2017); 107 FERC ¶ 61,272 at P 8 (2008).

148 FERC made an exception for Kentucky when it determined that RERRAs must obtain FERC approval prior to excluding EE. FERC explained that "the Commission accepted such condition at the time the Kentucky Commission approved the integration of Kentucky Power into PJM." 161 FERC ¶ 61,245 at P 66 (2017).

Table 6-54 Energy efficiency resources (MW): 2011/2012 through 2025/2026 Delivery Years

Delivery Year	EE Paid (MW)	Total RPM Cleared (UCAP MW)	EE MW/ Capacity MW	EE Revenue
2011/2012	76.4	134,182.6	0.1%	$139,812
2012/2013	666.1	141,295.6	0.5%	$11,408,552
2013/2014	904.2	159,844.5	0.6%	$21,598,174
2014/2015	1,077.7	161,214.4	0.7%	$42,308,549
2015/2016	1,189.6	173,845.5	0.7%	$66,652,986
2016/2017	1,723.2	179,773.6	1.0%	$68,709,670
2017/2018	1,922.3	180,590.5	1.1%	$86,147,605
2018/2019	2,296.3	175,996.0	1.3%	$103,105,796
2019/2020	2,528.5	177,064.2	1.4%	$92,569,666
2020/2021	3,569.5	174,023.8	2.1%	$101,348,169
2021/2022	4,806.2	174,713.0	2.8%	$185,755,803
2022/2023	5,734.8	150,465.2	3.8%	$135,265,303
2023/2024	5,896.4	150,143.9	3.9%	$93,603,058
2024/2025	7,716.0	154,362.5	5.0%	$130,780,274
2025/2026	1,493.2	137,733.6	1.1%	$147,950,487

Table 6-55 shows the total revenues to energy efficiency based on the zone in which they are located, as of June 1 for the 2024/2025 and 2025/2026 Delivery Years.

Table 6-55 Energy efficiency resource revenue by zone: 2024/2025 and 2025/2026 Delivery Years

	Revenue		Percent of EE Revenue	
Zone	2024/2025	2025/2026	2024/2025	2025/2026
AECO	$2,900,594	$1,582,433	2.2%	1.1%
AEP	$8,311,932	$11,932,785	6.4%	8.1%
APS	$4,019,526	$6,215,064	3.1%	4.2%
ATSI	$6,165,467	$6,155,174	4.7%	4.2%
BGE	$10,563,637	$12,102,754	8.1%	8.2%
COMED	$10,328,888	$28,316,443	7.9%	19.1%
DAY	$1,347,504	$1,607,671	1.0%	1.1%
DEOK	$6,482,315	$2,174,691	5.0%	1.5%
DOM	$9,388,297	$23,822,243	7.2%	16.1%
DPL	$17,479,123	$3,006,666	13.4%	2.0%
DUQ	$1,385,670	$1,750,387	1.1%	1.2%
JCPL	$6,373,282	$5,762,243	4.9%	3.9%
METED	$2,834,056	$2,096,549	2.2%	1.4%
PECO	$11,209,242	$12,335,236	8.6%	8.3%
PENELEC	$2,556,322	$1,699,550	2.0%	1.1%
PEPCO	$7,075,048	$7,305,169	5.4%	4.9%
PPL	$6,910,670	$4,155,526	5.3%	2.8%
PSEG	$15,386,096	$15,713,157	11.8%	10.6%
RECO	$62,605	$216,746	0.0%	0.1%
Total	$130,780,274	$147,950,487	100.0%	100.0%

As defined in the RAA, each LSE incurs a Locational Reliability Charge, subject to certain offsets and other adjustments as described in Attachment DD, Sections 5.14B through 5.14E and Section 5.15.[149] Locational Reliability Charges are equal to the LSE's Daily Unforced Capacity Obligation in a zone during the Delivery Year multiplied by the applicable Final Zonal Capacity Price in the zone. The Tariff does not define the allocation of EE revenue requirements to load in RPM. In practice, PJM allocates total EE revenue requirements to load prorata based on final zonal UCAP obligations. As a result, the allocation of EE costs to zones is not equal to the revenue requirement of EE resources located in that zone. Zones in which no EE resources are located are allocated a share of total EE revenue requirements based on their share of the total PJM UCAP obligation. Table 6-56 and Table 6-57 shows the zonal revenue requirement of EE resources compared to the zonal allocation of total EE revenue requirements to load. Where a zone's load charge is greater than the revenue requirement of EE resources located in that zone, the zone's customers are subsidizing the revenue requirement of EE resources located in other zones. Where a zone's load charge is less than the revenue requirement of EE resources located in that zone, the zone's customers are receiving a subsidy from customers located in other zones.

Table 6-56 Energy efficiency zonal load charges and revenues: 2024/2025 Delivery Year

		2024/2025		
Zone	LDA	EE Load Charge	EE Revenue	EE Load Charge minus Revenue
AE	EMAAC	$2,535,754	$2,900,594	($364,840)
AEP	RTO	$12,137,414	$8,311,932	$3,825,482
APS	RTO	$9,366,104	$4,019,526	$5,346,578
ATSI	ATSI	$12,926,950	$6,165,467	$6,761,484
BGE	BGE	$6,731,078	$10,563,637	($3,832,559)
COMED	COMED	$20,323,799	$10,328,888	$9,994,911
DAYTON	DAY	$3,380,646	$1,347,504	$2,033,141
DEOK	DEOK	$4,577,737	$6,482,315	($1,904,578)
DLCO	RTO	$2,826,017	$1,385,670	$1,440,347
DOM	RTO	$3,898,695	$9,388,297	($5,489,602)
DPL	EMAAC	$3,998,938	$17,479,123	($13,480,185)
EKPC	RTO	$2,506,944	$0	$2,506,944
JCPL	EMAAC	$6,142,999	$6,373,282	($230,283)
METED	MAAC	$3,147,572	$2,834,056	$313,516
OVEC	RTO	$64,743	$0	$64,743
PECO	EMAAC	$8,743,496	$11,209,242	($2,465,746)
PENLC	MAAC	$2,958,739	$2,556,322	$402,417
PEPCO	PEPCO	$6,244,429	$7,075,048	($830,619)
PL	PPL	$7,575,970	$6,910,670	$665,299
PS	PSEG	$10,273,581	$15,386,096	($5,112,515)
RECO	EMAAC	$418,669	$62,605	$356,064
Total		$130,780,274	$130,780,274	($0)

149 See PJM, Intra-PJM Tariffs, RAA, Article 7, §2.

Table 6-57 Energy efficiency zonal load charges and revenues: 2025/2026 Delivery Year

		2025/2026		
Zone	LDA	EE Load Charge	EE Revenue	EE Load Charge minus Revenue
AE	EMAAC	$2,449,029	$1,582,433	$866,596
AEP	RTO	$12,592,507	$11,932,785	$659,722
APS	RTO	$8,893,789	$6,215,064	$2,678,725
ATSI	ATSI	$12,837,721	$6,155,174	$6,682,547
BGE	BGE	$6,537,997	$12,102,754	($5,564,757)
COMED	COMED	$19,777,674	$28,316,443	($8,538,770)
DAYTON	DAY	$3,275,732	$1,607,671	$1,668,062
DEOK	DEOK	$4,429,801	$2,174,691	$2,255,110
DLCO	RTO	$2,720,453	$1,750,387	$970,066
DOM	DOM	$23,482,297	$23,822,243	($339,946)
DPL	EMAAC	$3,905,601	$3,006,666	$898,935
EKPC	RTO	$2,459,803	$0	$2,459,803
JCPL	EMAAC	$5,953,711	$5,762,243	$191,468
METED	MAAC	$3,098,582	$2,096,549	$1,002,033
OVEC	RTO	$62,158	$0	$62,158
PECO	EMAAC	$8,436,927	$12,335,236	($3,898,309)
PENLC	MAAC	$2,900,712	$1,699,550	$1,201,161
PEPCO	PEPCO	$6,047,984	$7,305,169	($1,257,185)
PL	PPL	$7,516,987	$4,155,526	$3,361,461
PS	PSEG	$10,165,958	$15,713,157	($5,547,199)
RECO	EMAAC	$405,064	$216,746	$188,318
Total		$147,950,487	$147,950,487	($0)

The ownership of Energy Efficiency is highly concentrated. The combined market share of the four largest companies ranges from 90 to 99 percent of all paid Energy Efficiency MW. The HHI for Energy Efficiency resources shows that ownership of EE for the entire market is highly concentrated for each of the last six delivery years. Table 6-58 shows the HHI value for paid Energy Efficiency MW and the market share of the four largest suppliers by delivery year for the entire market.

Table 6-58 Energy Efficiency HHI: 2019/2020 through 2025/2026

Delivery Year	HHI	Structure	Top 4 Market Share
2019/2020	3574	Highly Concentrated	90.6%
2020/2021	3005	Highly Concentrated	89.8%
2021/2022	3409	Highly Concentrated	91.6%
2022/2023	5803	Highly Concentrated	99.1%
2023/2024	6029	Highly Concentrated	99.9%
2024/2025	5749	Highly Concentrated	98.0%
2025/2026	2804	Highly Concentrated	96.0%

The ownership of Energy Efficiency is also highly concentrated on an LDA basis as shown by the HHI levels. The individual LDA HHI values cannot be made public based on PJM's confidentiality rules. Table 6-59 shows the HHI value for paid MW by LDA for the 2024/2025 and 2025/2026 Delivery Years.

Table 6-59 Energy Efficiency HHI by LDA

	Structure	
LDA	2024/2025	2025/2026
ATSI	Highly Concentrated	Highly Concentrated
ATSI-CLEVELAND	Highly Concentrated	Highly Concentrated
BGE	Highly Concentrated	Highly Concentrated
COMED	Highly Concentrated	Highly Concentrated
DAY	Highly Concentrated	Highly Concentrated
DEOK	Highly Concentrated	Highly Concentrated
DOM	Not a Modeled LDA	Highly Concentrated
DPL-SOUTH	Highly Concentrated	Highly Concentrated
EMAAC	Highly Concentrated	Highly Concentrated
MAAC	Highly Concentrated	Highly Concentrated
PEPCO	Highly Concentrated	Highly Concentrated
PPL	Highly Concentrated	Highly Concentrated
PS-NORTH	Highly Concentrated	Highly Concentrated
PSEG	Highly Concentrated	Highly Concentrated
RTO	Highly Concentrated	Highly Concentrated

Table 6-60 shows how EE MW are distributed across LDAs. For example, 22.6 percent of all EE MW were in COMED in the 2025/2026 Delivery Year.

Table 6-60 Energy Efficiency Share by LDA

	Percent of EE	
LDA	2024/2025	2025/2026
ATSI	6.9%	4.2%
ATSI-CLEVELAND	0.7%	0.4%
BGE	5.0%	5.0%
COMED	13.8%	22.6%
DAY	1.7%	1.2%
DEOK	2.4%	1.7%
DPL-SOUTH	1.3%	10.3%
EMAAC	15.1%	1.6%
MAAC	3.9%	15.1%
PEPCO	5.2%	2.7%
PPL	5.1%	5.4%
PS-NORTH	5.1%	3.1%
PSEG	5.3%	6.7%
RTO	28.6%	5.6%

Peak Shaving Adjustment

Peak Shaving Adjustment (PSA) provides an alternative means for demand response to participate in the Reliability Pricing Model (RPM). Rather than being on the supply side of the capacity market, a PSA participates on the demand side through a modified peak load forecast for the zone in which the Peak Shaving Adjustment resources are located. The peak shaving adjusted load forecast is included in the VRR curve. An important issue is that the resultant reduction in capacity obligation is socialized across all loads in the zone rather than directly benefitting the resources providing the Peak Shaving Adjustment.[150] 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.[151] Any resource selling a PSA must reduce load on any day in which its trigger is met or exceeded. The trigger is based on the actual maximum daily temperature humidity index (THI) for the relevant PJM zone. When the trigger is met, the PSA must comply with its defined offer parameters including number of hours of interruption. Failure to operate to these parameters will lead to a reduction in the peak shaving adjustment value in future delivery years. Performance is measured based on the aggregated Customer Baseline (CBL). PJM applies a three year rolling average of the annual peak shaving performance ratings to the program's total participating MW in order to determine its peak shaving adjustment.

Distributed Energy Resources

Distributed Energy Resources (DER) include generation connected to distribution level facilities, behind the meter generation, and energy storage facilities connected to the distribution grid or to load. FERC issued Order No. 2222 on September 17, 2020, with the goal of removing barriers for small distributed resources to enter the wholesale market by allowing them to aggregate in order to encourage competition, but larger resources, up to 5 MW, can participate.[152] 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.[153] 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.

150 See "Peak Shaving Adjustment Proposal," Docket No. ER19-511-000 (December 7, 2018).
151 "PJM Manual 19: Load Forecasting and Analysis," Attachment D, Rev. 37 (Dec. 18, 2024).
152 See 172 FERC ¶ 61,247 at PP 6–7.
153 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>.

Getting the rules right at the beginning of DER development is essential to the active and effective participation of DER in the wholesale power markets in a manner that enhances rather than undermines the efficiency and competitiveness of the power markets. In addition, getting the implementation details right is critical in keeping the original intention of Order No. 2222 to enhance competition in wholesale markets while removing barriers for small distributed resources. To date, PJM is not meeting these objectives.

Nodal Aggregation and Size

The PJM market is a nodal market. Nodal markets provide efficient price signals to resources in an economically dispatched, security constrained market. Aggregation behind a single node is feasible, is consistent with the nodal market principle, and will encourage competition. The accepted DER Aggregation Participation Model allows multinodal aggregation for small resources that satisfy a few conditions. Energy injection from DERs across multiple nodes, even if it is small, will change congestion patterns that PJM would not have the ability to predict and control. Allowing DER aggregation across nodes even for small resources is not necessary and would distort the nodal market signals that indicate where capacity and energy are needed and their impacts on congestion. The MMU recommends that PJM use a nodal approach for DER participation in PJM markets that excludes multinodal aggregation.

The accepted DER Aggregation Participation Model does not propose a maximum size requirement for DER Aggregation Resources. This loophole would allow larger DERs to divide one larger resource into multiple DERs less than 5 MW and register them as one DER Aggregation Resource, undermining the intent of the DER approach. To avoid this loophole, there should be a maximum size requirement on DER Aggregation Resources. The MMU recommends that PJM include a 5.0 MW maximum size cap on DER aggregations.

EDC Role

The EDCs' dual role as the distribution system operator and as a DER Aggregator is a threat to PJM's competitive market. When an EDC, acting in its proposed role as a market participant, controls its competitors' access to the market, the result is not structurally competitive. The result would be to create barriers to competition, exactly the opposite of FERC's intent. EDCs have a very significant role to play as designers, builders and managers of the local grids, without competing with DER providers. The accepted DER Aggregation Participation Model does not prevent EDCs from serving as DER aggregators or address the market power issues, based on a reference to the provision of Order No. 2222 that prohibits RTOs/ISOs from limiting the business models under which DER aggregators can operate. FERC, however, stated that it could revisit the EDCs' role in the PJM markets, if "evidence of undue discrimination regarding the participation of DER aggregations in RTO/ISO markets" is discovered.[154] 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.[155] However, the proposed tariff language does not explicitly define the MMU's role in monitoring or mitigating the potential exercise of market power by EDCs. To enable efficient and effective market monitoring, EDCs and DERAs should be explicitly required to provide information requested by the MMU. The MMU recommends that the Commission require PJM to include in OATT Attachment M a statement explicitly affirming that the Market Monitor's role includes the right to collect information from EDCs and DERA related to actions taken on the distribution system related to DER Aggregation Resources.

154 182 FERC ¶ 61,143 at P 334.
155 See 188 FERC ¶ 61,076 at P169.

Net Metering Resources

A net metering resource is a single electric customer location that has both generation and load, where the generation can exceed the load, and the customer pays for energy or receives compensation for energy based on the net energy output measured at the customer meter. Retail customers on a net metering tariff with their distribution utility pay the retail rate when consuming and are paid the retail rate when selling energy. These resources cannot participate in the energy or capacity markets, because they already receive full compensation for their output. That retail rate compensation includes credits for ancillary services charges.

According to PJM, no net metering resources in the PJM footprint provide ancillary services as part of a retail program.[156] From PJM's perspective, this means all net metering resources in its territory are eligible to participate in its ancillary services market.[157] PJM argues that even if a resource is compensated for the same service at the retail and the wholesale level, it should not be considered double counting. Under this proposal, a net metered resource that receives credits through its retail rate for reducing its ancillary services purchase can also receive payment from PJM for providing the same ancillary services. That is clearly double counting. The accepted DER Aggregation Participation Model allows EDCs to raise concerns about double counting but neither PJM nor an EDC may preclude a Component DER from providing ancillary services based on the resources being compensated for ancillary services at the retail level. No resource should be paid more than once for its services. If the net energy metering resources receive credits at a rate that includes compensation for ancillary services, that means they are providing the service and being compensated for it. The MMU recommends that net metering resources be prohibited from participating in wholesale ancillary services markets if they are compensated for the service at the retail level.

On December 19, 2025, PJM submitted a tariff revision filing at FERC proposing to create a new participation model called Economic Load Response Regulation Only Participants.[158] 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.[159] [160] FERC issued a deficiency letter to PJM on February 13, 2026.[161]

156 See Order No. 2222 Compliance Filing of PJM Interconnection, L.L.C., Docket No. ER22-962 (February 1, 2022) at 41.
157 FERC Docket No. ER22-962-005 at 15.
158 PJM Interconnection, L.L.C., Economic Load Response Regulation Only Participants, Docket No. ER26-846-000, (December 19, 2025).
159 Monitoring Analytics, L.L.C., Comments of the Independent Market Monitor for PJM Interconnection, L.L.C., Docket No. ER26-846 (January 9, 2026).
160 Monitoring Analytics, L.L.C., Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, ER26-846 (February 11, 2026).
161 FERC Deficiency Letter, Docket No. ER26-846 (February 13, 2026).