Monitoring Analytics

Analysis of the 2027/2028 RPM Base Residual Auction Part B

The Independent Market Monitor for PJM

July 9, 2026

© Monitoring Analytics 2026 | www.monitoringanalytics.com

Introduction

This report prepared by the Independent Market Monitor for PJM (IMM or MMU), is Part B in a series of reports that review the functioning of the twenty first Reliability Pricing Model (RPM) Base Residual Auction (BRA) for the 2027/2028 Delivery Year which was held from December 4 to 10, 2025, and respond to questions raised by PJM members and market observers about that auction. The MMU has previously prepared one report on specific issues in the 2027/2028 BRA: Part A.[1] Part B is the final report related to the 2027/2028 BRA. Part A and Part B together are the MMU's report on the 2027/2028 BRA. The MMU prepares a report for each RPM Base Residual Auction.

For the second time since the introduction of the RPM capacity market design, the 2027/2028 BRA used a VRR curve with both a defined maximum price and a defined minimum price. The VRR curve has always had a maximum price but never a minimum price greater than zero. The dollar values of the maximum and minimum prices were based on the Agreement between Governor Shapiro of Pennsylvania and PJM that was incorporated in a PJM filing with FERC.[2] That VRR curve with the defined maximum and minimum price is referred to in this report as the actual VRR curve. The VRR curve that would have been used absent the Agreement is referred in this report as the unrestricted VRR curve, although it also has defined price and MW points. The unrestricted VRR curve has a higher maximum price, no minimum price and a point A at a lower MW level than the VRR curve used in the 2027/2028 BRA (see Figure 1).

This Part B of the report, together with Part A, addresses, explains and quantifies the basic market outcomes in the 2027/2028 BRA. Part B also addresses additional issues including: market power; competitive offers; the CP model; the ELCC design; the market seller offer cap (MSOC); MOPR; the capacity must offer requirement; the definition of avoidable costs; the use of forward looking net revenues; the matching of seasonal offers; Capacity

---

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

2 On December 30, 2024, in Docket No. EL25-46-000, Governor Josh Shapiro and the Commonwealth of Pennsylvania filed a complaint against PJM asserting that the maximum price for PJM's capacity auctions is unjust and unreasonable. The Governor and PJM reached an Agreement. On February 20, 2025, in Docket No. ER25-1357-000, pursuant to FPA section 205, PJM submitted proposed revisions to its Tariff to establish a specific maximum price and minimum price for all RPM auctions for the 2026/2027 and 2027/2028 Delivery Years, consistent with the Agreement. On April 21, 2025, FERC issued an order accepting PJM's proposal to establish a temporary capacity market price cap and floor for the 2026/2027 and 2027/2028 Delivery Years. 191 FERC ¶ 61,066 (April 21, 2025).

Transfer Rights (CTRs); the definition of reliability that leads to RMRs; and the market clearing model used by PJM.

The market power rules applied in the 2021/2022 BRA and the 2022/2023 BRA were significantly flawed, as illustrated by the results of the 2021/2022 BRA and the 2022/2023 BRA.[3] Competitive outcomes require continued improvement of the rules and ongoing monitoring of market participant behavior and market performance. The incorrect definition of the offer caps in the 2021/2022 BRA and the 2022/2023 BRA resulted in noncompetitive offers and noncompetitive outcomes in both auctions. The market power rules were corrected by the Commission in an order issued on September 2, 2021, (September 2nd Order) but the modified market power rules were not implemented in the 2022/2023 BRA.[4] The result was that capacity market prices were above the competitive level in the 2022/2023 BRA. The corrected MSOC rules were applied in the 2023/2024 BRA and the 2024/2025 BRA and were essential to the competitive results of the 2023/2024 BRA and the 2024/2025 BRA. The corrected MSOC rules were also applied in the 2025/2026 BRA with the result that resources subject to the MSOC rules behaved competitively. PJM introduced and FERC accepted new flaws in the MSOC rules effective for the 2027/2028 BRA. These flaws were the inclusion of the CPQR component of ACR with no net revenue offset and the use of segmented offer caps.[5]

Only 1.0 percent of offers (14 generation resources) requested unit specific cost review for the 2027/2028 Base Residual Auction. Two resources of those 14 did not reach agreement with the MMU. The MMU calculated offer caps for 943 generation resources that submitted capacity offers, most of which (68.8 percent) were default ACR based.

The MMU concludes that the results of the 2027/2028 Base Residual Auction were not competitive as a result of the inclusion of large new data center loads in the load forecast, the lack of a queue for the addition of large new data center loads, the performance assessment interval (PAI) penalties that are part of the CP design, PJM's ELCC approach,

---

[3] See "Analysis of the 2021/2022 RPM Base Residual Auction - Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018) and "Analysis of the 2022/2023 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20222023_RPM_BRA_20220222.pdf>.

[4] 176 FERC ¶ 61,137 (September 2nd Order).

[5] See Comments of the Independent Market Monitor for PJM, Docket No. ER25-785-000 (January 10, 2024) at 7–15; Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, ER25-785-000 (February 18, 2025) at 4–7; Request for Rehearing of the Independent Market Monitor for PJM, ER25-785-000 (March 19, 2025) at 2–11.

the definition of market seller offer caps, the failure to extend the RPM must offer requirement to demand resources, and the product definition and lack of market power mitigation for demand resources. The BRA prices do not reflect supply and demand fundamentals but reflect, in significant part, PJM decisions about the definition of supply and demand. PJM filed changes that were approved by FERC and included in the 2027/2028 BRA to adopt two of the MMU's recommendations, the inclusion of specific RMR resources as supply in RPM auctions for the 2026/2027 through the 2028/2029 Delivery Year and the elimination of the categorical exemption to the RPM must offer requirement for all but demand resources.[6] [7]

Capacity market prices in the 2027/2028 BRA were the result of both competitive forces and significantly flawed market design. The MSOC rules resulted in competitive offers and prevented noncompetitive offers from those subject to the rules. Some elements of the market design suppressed prices, primarily the inclusion of poorly defined demand resources as capacity supply. The elements of the market design that increased prices dominated in the 2027/2028 BRA. The high clearing prices in 2027/2028 BRA were primarily the result of existing and forecast data center load and market design flaws.

The capacity market exists to make the energy market work, by providing the additional net revenues required for the incentive to invest in new units and to maintain old units. The definition of capacity is not the ability to provide energy during one peak hour or five peak hours, as implied by the methods used by PJM and EDCs/LSEs to allocate the costs of capacity to load. The obligations of capacity resources include the requirement to offer their full ICAP in the energy and reserves markets every day. The need for the energy from capacity is not limited to one peak hour or five peak hours. Customers require energy from capacity resources all 8,760 hours per year. Rather than develop a complicated seasonal capacity market based on an arbitrary definition of seasons that requires an arbitrary allocation of costs between seasons and a doubling of the MSOC values, the hourly value of the energy from capacity should be explicitly recognized in the capacity market.[8] An hourly capacity market model with a single annual clearing price

---

6 See Letter Order, FERC Docket No. ER25-682-001 (April 29, 2025). See also 193 FERC ¶ 61,234 (2025).

7 190 FERC ¶ 61,117 (2025).

8 See "Executive Summary of IMM Capacity market design proposal: Sustainable Capacity Market (SCM)," IMM presentation to the PJM Board of Managers, (August 23, 2023) <https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_RASTF-CIFP_SCM_Executive_Summary_20230816.pdf>.

would more accurately reflect the reliability contribution of each resource, provide strong and effective performance incentives and result in competitive clearing prices.

Conclusions

The capacity market is, by design, always tight in the sense that total supply is generally only slightly larger than demand. The PJM Capacity Market is a locational market and local markets frequently have different supply demand balances than the aggregate market. While the market may be long at times, that is not the equilibrium state. Capacity in excess of demand is not sold and, if it does not earn or does not expect to earn adequate revenues from the full set of PJM markets, or does not have value as a hedge, may be expected to retire, provided the market sets appropriate price signals to reflect the availability of excess supply. Capacity in excess of demand means capacity in excess of the demand as defined by the capacity demand curve, called the Variable Resource Requirement (VRR) curve. PJM rules require load to pay for the level of capacity defined by the VRR curve. Correctly defined, excess capacity means capacity in excess of the peak load forecast plus the reserve margin, the level of capacity PJM is required to purchase in order to maintain reliability.

PJM's required demand for capacity, based on reliability requirements, includes expected peak load plus a required reserve margin, but most points on the downward sloping part of the demand curve, the VRR curve, exceed peak load plus the reserve margin. The shape of the VRR curve results in the purchase of excess capacity and substantially higher payments by customers. The required demand for capacity defines a vertical demand curve equal to expected peak load plus a required reserve margin.

PJM's required demand for capacity includes forecasts of large load additions through a defined process in which the Electric Distribution Companies (EDCs) provide information to PJM about expected large load additions. This process worked without significant issues prior to the emergence of data centers. It does not work now because of the significant uncertainty about data center additions. PJM does not critically evaluate the large load additions because such evaluation is outside their expertise and control. The result is that capacity market prices can be significantly affected by forecast data center load that bears little known resemblance to reality. The solution to this issue is not for PJM to try to check on the forecast data center load, but to hold a separate capacity market auction for data center load in which the demand curve is defined by data centers that commit to paying for a defined level of capacity if they clear. The result of running a separate auction is to remove the impact of data center load and load forecasts from other customers. The impact of a separate auction is also to provide a vehicle for data centers to

acquire capacity if they have not already entered into bilateral contracts for new capacity. This process is referred to as bring your own new generation or BYONG.[9]

For the 2027/2028 RPM Base Residual Auction, total reserves were 16,977.4 MW, which is 6,516.6 MW (UCAP) short of the required reserve level of 23,494.0 MW (UCAP). The level of committed demand resources in the 2027/2028 BRA was 7,165.0 MW, meaning the PJM markets will rely on demand resources as part of the required reserve margin, rather than as excess above the required reserve margin. This is not consistent with the defined obligations of DR compared to other capacity resources. DR capacity resources do not have a must offer obligation in the energy market. DR capacity resources do not have a must offer obligation in the capacity market. The definition of performance for DR is not to provide a defined incremental level of MW when called but is only to be at a defined level of demand. DR capacity resources do not have a defined market seller offer cap. PJM markets for the first time in the 2025/2026, 2026/2027, and 2027/2028 Delivery Years will rely on demand response resources as part of the required reserve margin, rather than as excess above the required reserve margin. PJM markets for the first time in the 2025/2026, 2026/2027, and 2027/2028 Delivery Years will experience the implications of the definition of demand resources as a purely emergency capacity resource, when demand resources are a significant share of required reserves. Nonetheless, as another significant flaw in the market design, PJM does not include DR in its definition of primary or secondary reserves in the energy market. DR, for all these reasons, is an inferior resource in the capacity market. PJM does not have clear rules defining when the operators must call on DR.

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

The demand for capacity in the capacity market is almost entirely inelastic because the market rules require loads to purchase their share of the system capacity requirement. The downward sloping portion of the VRR curve is everywhere inelastic. The result is that any supplier that owns more capacity than the typically small difference between total supply and the VRR defined demand is individually pivotal and therefore has structural market power. Any supplier that, jointly with two other suppliers, owns more capacity than the

---

[9] See "IMM Reliability Backstop Auction Design Proposal," (June 30, 2026) <https://www.monitoringanalytics.com/reports/Presentations/2026/IMM%20Backstop%20auction%20design%20proposal%20-%20V6%202026.06.19.pdf>. See also "IMM Curtailable Load Proposal," (June 30, 2026) <https://www.monitoringanalytics.com/reports/Presentations/2026/IMM%20Connect%20and%20Manage%20proposal%20-%20V2%202026.06.19.pdf>.

difference between supply and the VRR defined demand either in aggregate or for a local market is jointly pivotal and therefore has structural market power.

The market design for capacity leads, almost unavoidably, to structural market power in the capacity market. The capacity market is unlikely ever to approach a competitive market structure in the absence of a substantial and unlikely structural change that results in much greater diversity of ownership. Market power is and will remain endemic to the structure of the PJM Capacity Market. Nonetheless a competitive outcome can be assured by appropriate market power mitigation rules. That does not mean that further consolidation through mergers and acquisitions should be permitted by the Commission. Detailed market power mitigation rules are included in the PJM Open Access Transmission Tariff (OATT or Tariff). Reliance on the RPM design for competitive outcomes means reliance on the market power mitigation rules. Attenuation of those rules means that market participants are not able to rely on the competitiveness of the market outcomes.

In the capacity market, as in other markets, market power is the ability of a market participant to increase the market price above the competitive level or to decrease the market price below the competitive level. In order to evaluate whether actual prices reflect the exercise of market power, it is necessary to evaluate whether market offers are consistent with competitive offers. Net avoidable costs define a competitive offer in the capacity market, regardless of whether the concern is efforts to increase the market price above the competitive level or to reduce the market price below the competitive level. It is basic economics that a competitive offer is a competitive offer. There is not one competitive offer for those who would suppress market prices and another one for those would inflate market prices. As in all other markets, the competitive offer in the capacity market is the marginal cost of capacity.

The correct definition of a competitive offer is the marginal cost of capacity, net avoidable costs (ACR), where ACR includes an explicit accounting for the costs of mitigating risk (CPQR), including the risk associated with capacity market nonperformance penalties, and the relevant costs of acquiring fuel (AFAE), including natural gas and where net revenue from the energy and ancillary services markets offsets ACR, without exception for CPQR and without the arbitrary creation of offer segments.[10] [11]

The MMU, as part of the process for all RPM auctions, verifies the reasonableness of avoidable cost data and calculations; calculates unit specific net revenues; calculates the

---

[10] Complaint of the Independent Market Monitor for PJM, Docket No. EL19-47, February 21, 2019 ("IMM MSOC Complaint").

[11] 174 FERC ¶ 61,212; 176 FERC ¶ 61,137; *order on reh'g*, 178 FERC ¶ 61,121.

derived offer caps based on submitted data for resources that submitted unit specific data and for resources that submitted offers based on default ACR values; reviews Minimum Offer Price Rule (MOPR) unit specific exception requests; reviews offers for Planned Generation Capacity Resources; verifies capacity exports, including firm contracts and export offers based on opportunity costs; reviews requests for exceptions to the RPM must offer requirement; reviews requests for exceptions to the additional, specific CP must offer requirement; reviews documentation for Intermittent Resources and Capacity Storage Resources to support CP eligibility; verifies clearing prices based on the supply and demand (VRR) curves; and verifies that the market power tests were applied correctly.[12]

All participants to which the three pivotal supplier (TPS) test was applied (in the RTO market) failed the three pivotal supplier test. The result was that offer caps were applied to all sell offers for Existing Generation Capacity Resources when the capacity market seller did not pass the test, the submitted sell offer exceeded the tariff defined offer cap, and the submitted sell offer, absent mitigation, would have resulted in a higher market clearing price.[13] [14] A competitive offer in the capacity market is equal to net ACR.[15] The ACR values were based on data provided by the participants, or default ACR values, and were consistent with competitive offers for the relevant capacity.

Based on the data and this review, the MMU concludes that the results of the 2027/2028 RPM Base Residual Auction were not competitive.

The MMU concludes that the failure to recognize and address the role of large data center loads is a direct cause of higher prices and will continue to result in even higher prices unless the related issues are addressed. The MMU also concludes that market prices were significantly affected by other flaws in the capacity market rules and in the application of

---

12 Attachment A reviews the MMU calculation of clearing prices and includes recommendations for improving PJM's market clearing algorithm.

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

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

15 174 FERC ¶ 61,212 ("March 18th Order") at 65.

the capacity market rules by PJM, including PJM's approach to ELCC, the shape of the VRR curve and the inclusion of sell offers from DR.

The MMU concludes that, although not an issue in the 2027/2028 auction, the rules permit the exercise of market power without mitigation for seasonal products through uplift payments for noncompetitive offers, rather than through higher prices.[16] The issue should be addressed immediately in order to prevent the impact from increasing and because the solution is simple.

Recommendations

Changes to the capacity market design have addressed some but not all of the significant recommendations made by the MMU in prior reports. The MMU had recommended the elimination of the 2.5 percent demand adjustment (Short-Term Resource Procurement Target). The MMU had recommended that the performance incentives in the pre-CP capacity market design be strengthened by, among other things, eliminating the incorrect definition of forced outages. The MMU had recommended that the net revenue calculation used by PJM to calculate the Net Cost of New Entry (CONE) VRR parameter reflect the actual flexibility of units in responding to price signals rather than using assumed fixed operating blocks that are not a result of actual unit limitations. The MMU had recommended that all capacity imports be required to be pseudo tied in order to ensure that imports are as close to full substitutes for internal, physical capacity resources as possible. The MMU had recommended that the definition of demand side resources be modified in order to ensure that such resources are full substitutes for and provide the same value in the capacity market as generation resources, although this recommendation has not been incorporated in PJM rules. The MMU had recommended that both the Limited and the Extended Summer DR products be eliminated and that the restrictions on the availability of Annual DR be eliminated in order to ensure that the DR product has the same unlimited obligation to provide capacity year round as Generation Capacity Resources. The MMU had recommended that the EE addback calculation be corrected. The MMU had recommended that the default Avoidable Cost Rate (ACR) escalation method be modified in order to ensure accuracy and eliminate double counting. The MMU had recommended that specific RMR resources be included as supply. The MMU had recommended the elimination of the categorical exemption to the RPM must offer requirement. The MMU had recommended that the capacity of RMR units be included as supply in RPM auctions.

---

[16] PJM uses various terms for uplift including make whole payments (often used in the capacity market) and operating reserve payments (often used in the energy market). The term uplift is used in this report to refer to out of market payments made by PJM to market participants in addition to market revenues.

The MMU recommends elimination of the key remaining components of the CP model because they interfere with competitive outcomes in the capacity market and create unnecessary complexity and risk.[17] The primary remaining component is the definition and implementation of penalties related to PAI. Such penalties are not an effective incentive and are an irrational incentive in the case of solar and wind resources that are penalized when ambient conditions that are already embedded in their ELCC values (nighttime and no wind) prevent their operation.

The MMU has concluded that ELCC is not a viable method for determining the reliability contributions of capacity resources. The MMU has proposed a replacement for the PJM ELCC approach that is based on the actual hourly availability of all individual generators.[18] The MMU recommends that PJM's ELCC model be replaced.

The MMU recommends that PJM evaluate the shape of the VRR curve. The shape of the VRR curve directly results in load paying substantially more for capacity than load would pay with a vertical demand curve. More specifically, the MMU recommended that the VRR curve be rotated halfway towards the vertical demand curve at the reliability requirement as a transition step in the 2022 Quadrennial Review.[19] The shape of the VRR curve was discussed in the stakeholder process. PJM reviewed the impact of a range of VRR shape options in the 2022 Quadrennial Review, and PJM agreed that the VRR curve should be rotated towards the vertical demand curve, but by only approximately one quarter of the way towards vertical.[20] That change was implemented in the 2026/2027 BRA.[21]

---

17 See "Executive Summary of IMM Capacity market design proposal: Sustainable Capacity Market (SCM)," (August 16, 2023) <https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_RASTF-CIFP_SCM_Executive_Summary_20230816.pdf>. See additional related MMU presentations at <https://www.monitoringanalytics.com/reports/Presentations/2023.shtml>.

18 For additional details on the MMU proposal see "Executive Summary of the IMM Capacity Market Design Proposal: Sustainable Capacity Market (SCM)", Independent Market Monitor for PJM (August 16, 2023) <http://www.monitoringanalytics.com/reports/Presentations/2023/IMM_RASTF-CIFP_SCM_Executive_Summary_20230816.pdf>.

19 See *Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM*, Docket No. ER22-2984-000 (November 16, 2022).

20 See PJM Filing, Docket ER22-2984-000 (September 30, 2022) at 9; MIC Special Sessions: 2022 Quadrennial Review.

21 182 FERC ¶ 61,073 (February 14, 2023).

The MMU recommends that PJM not sell back any capacity in any Incremental Auction ("IA"), at much lower prices, procured in a BRA. If excess capacity is procured in a BRA at very significant cost to load, that capacity should not be sold back at a steep discount. Given PJM's assertions of the benefits of over procuring capacity, it has never been explained why load should pay a high price for capacity in a BRA and sell it back at very low prices in an IA. Such sales are inconsistent with PJM's assertion that additional capacity purchases have value.[22] In addition, such sales suppress prices in incremental auctions and provide inefficient incentives for demand resource offer behavior and an inefficient incentives to replace capacity sales.[23]

The MMU recommends the enforcement of a consistent definition of a capacity resource. The MMU recommends that the tariff requirement to be a physical resource be enforced and enhanced. The requirement to be a physical resource should apply at the time of auctions and should also constitute a commitment to be physical in the relevant delivery year. The requirement to be a physical resource should be applied to all resource types, including planned generation, demand resources, and imports.[24] [25] The requirement to be a physical resource is not currently applied to DR, which are permitted to submit marketing plans rather than evidence of physical resources in the BRA. All DR should be on the demand side of the market rather than on the supply side. If DR remains on the supply side, it should be required to be an economic resource rather than a purely emergency resource and to have all the obligations of any other capacity resource.

The MMU recommends that PJM require all market participants to meet their deliverability requirements under the same rules. PJM's practice of giving away winter CIRs that appear to exist because other resources paid for the supporting network upgrades, requires annual capacity resources to subsidize the interconnection costs of

---

22 "PJM Manual 18: PJM Capacity Market," § 3.1 Overview of Demand in the Reliability Pricing Model, Rev. 62 (Dec. 17, 2025).

23 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).

24 See *PJM Interconnection, L.L.C,* Comments of the Independent Market Monitor for PJM, Docket No. ER14-503-000. (December 20, 2013).

25 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).

intermittent resources and artificially increases the capacity value of the winter resources. Winter CIRs should be available to resources based on their contribution to reliability. Thermal resources with incremental winter capacity based on ambient conditions should be permitted to offer that capacity and to be granted available winter CIRs based on their contribution to winter reliability compared to intermittent resources that currently receive all the winter CIRs.

The MMU recommends that the must offer rule in the capacity market apply to all capacity resources.[26] There is no reason to exempt demand side resources from the must offer requirement. The same rules should apply to all capacity resources. The capacity market was designed on the basis of a must buy requirement for load and a corresponding must offer requirement for capacity resources. The capacity market can work only if both are enforced.

The MMU recommends that the definition of avoidable costs in the tariff be corrected to be consistent with the economic definition. Avoidable costs are costs that are neither short run marginal costs, like fuel or consumables, nor fixed costs like depreciation and rate of return. Avoidable costs are the marginal costs of capacity and therefore the competitive offer level for capacity resources and therefore the market seller offer cap. Avoidable costs are the marginal costs of capacity whether a new resource or an existing resource. The tariff distinction between mothball and retirement avoidable costs is unsupported and should be eliminated. Avoidable costs are defined by the OATT to be the costs that a generation owner incurs as a result of operating a generating unit for one year, in particular the delivery year.[27] As a result, the tariff defines avoidable costs as the costs that a generation owner would not incur if the generating unit did not operate in the delivery year.

The MMU recommends that major maintenance costs be included in the definition of avoidable costs and removed from energy offers because such costs are avoidable costs and not short run marginal costs.[28] PJM arbitrarily modified the definition of avoidable

---

[26] See "Executive Summary of IMM Capacity market design proposal: Sustainable Capacity Market (SCM)," IMM presentation to the PJM Board of Managers, (August 23, 2023) <https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_RASTF-CIFP_SCM_Executive_Summary_20230816.pdf> and also; See *2025 Quarterly State of the Market Report for PJM: January through September*, Section 5: Capacity Market.

[27] OATT Attachment DD § 6.8 (b).

[28] *PJM Interconnection L.L.C.*, Docket Nos. ER19-210-000 and EL19-8-000, Responses to Deficiency Letter re: Major Maintenance and Operating Costs Recovery (February 14, 2019).

costs effective April 15, 2019, to exclude major maintenance costs.[29] [30] [31] The result was to reduce gross ACR values includable in capacity market offers below actual gross ACR levels and to reduce offer caps in the capacity market below the competitive level. This change affected offer caps in the 2023/2024 through 2025/2026 BRAs.

The MMU recommends using the lower of the cost or price-based energy market offer to calculate energy costs in the calculation of the historical net revenues which are an offset to gross ACR in the calculation of unit specific capacity resource offer caps based on net ACR. This recommendation was rejected by FERC.[32] The FERC approved approach, used in the 2021/2022 BRA through the 2025/2026 BRA, requires use of the price-based offer in most cases. The FERC approach requires the use of the cost-based offer when the resource offer is mitigated for market power and the cost-based offer is lower than the price-based offer. The FERC approach also requires the use of the cost-based offer when the price based offer is less than fuel costs plus environmental costs, even if the cost-based offer is greater than fuel cost plus environmental costs.[33] The higher the energy offer used in the calculation of net revenues, the lower the net revenues and the higher the net ACR offer cap. The FERC approach, used in most cases, results in lower net revenues and higher offer caps than calculated under the MMU approach.

The MMU recommends the use of historical energy and ancillary services (E&AS) net revenue offset scaled using forward looking prices for energy prices and fuel costs. The MMU recommends the use of forward LMPs calculated using real-time monthly on and off peak forward prices for the delivery year at the PJM Western Hub, adjusted to the zone and hour using the historical zonal, nodal and hourly real-time price differentials for each of the last three years. The MMU and PJM have been implementing this method for years in the calculation of the opportunity costs associated with environmental limits on the operation of generating units.[34]

---

29 *PJM Interconnection L.L.C.,* Docket Nos. ER19-210-000 and EL19-8-000, Responses to Deficiency Letter re: Major Maintenance and Operating Costs Recovery (February 14, 2019).

30 167 FERC ¶ 61,030 (April 15, 2019).

31 OATT Attachment DD § 6.8 (c).

32 See 155 FERC ¶ 61,281 (2016).

33 *See Order on Section 206 Investigation*, 154 FERC ¶ 61,151 (2016).

34 *See* "PJM Manual 15: Cost Development Guidelines," § 12.7 IMM Opportunity Cost Calculator, Rev. 47 (Oct. 1, 2025).

The MMU recommends that capacity market sellers be required to explicitly request and support the use of minimum MW quantities (inflexible sell offer segments) and that the requests only be permitted for defined physical reasons. Capacity market sellers are allowed to offer up to 10 sell offer segments for a resource and, for annual resources, specify a minimum MW quantity for every segment. The capacity market rules do not require the segments to be aligned with the physical operating attributes of the underlying capacity resource. A fully flexible offer or an inflexible offer of the entire unit may each be competitive offers, depending on the economic status of the unit. The use of segments not linked to the physical characteristics of units permits the exercise of market power through impacts on clearing prices and by requiring uplift payments when an entire segment or resource is not required in order to clear the market.

The MMU recommends that relatively small proposed increases in the capability of a Generation Capacity Resource be treated as an existing resource and subject to the corresponding market power mitigation rules and no longer be treated as planned and exempt from offer capping.

The MMU recommends that, as part of the MOPR unit specific standard of review, all projects be required to use the same basic modeling assumptions. That is the only way to ensure that projects compete on the basis of actual costs rather than on the basis of modeling assumptions.[35] This was a significant issue in the review of MOPR offer floors in the 2022/2023 BRA.

The MMU recommends that the RPM market power mitigation rules be modified to apply offer caps in all cases when the three pivotal supplier test is failed and the sell offer is greater than the offer cap in order to ensure that market power does not result in an

---

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

increase in uplift payments for seasonal products.[36] Under the seasonal capacity rules, the optimization considers the average cost of clearing seasonal offers, including an offer in each season. This can result in clearing seasonal sell offers for the higher cost season at offer prices that are not competitive and making seasonal uplift payments based on those high offer prices.

The MMU recommends that any combined seasonal products be required to be in the same LDA and at the same location, in order for the energy market and capacity market to remain synchronized and reliability metrics correctly calculated.

The MMU recommends that the value of CTRs be defined by the total MW cleared in the capacity market, the LDA internal MW cleared and the LDA imported MW cleared, and not redefined later prior to the delivery year. Capacity Transfer Rights (CTRs) are used to return capacity market congestion revenues to load, but the CTRs that result from market clearing prices and quantities are not included in final settlements for individual LDAs. The CTR issue also highlights a broader issue with differences between overall market clearing results and settlements for individual LDAs.

The MMU recommends that the market clearing results be used in settlements rather than the reallocation process currently used. As with CTRs, the underlying reasons for not using the market clearing results are not clear. Although not stated explicitly, the goal appears to be to reflect the fact that actual loads and load forecasts change between the auction and the delivery year. But the simple reallocation of capacity obligations based on changes in the load forecast does not reflect the BRA market results.

The MMU recommends that PJM improve the clarity and transparency of its CETL calculations. CETL is a critical parameter that can have significant impacts on capacity market outcomes. The changes in CETL that have affected market outcomes in this and prior auctions have not been well explained. CETL is relevant for transfers between LDAs and for imports to PJM. The MMU recommends that CETL include the ability to import capacity from outside PJM only where PJM capacity exists and where that capacity has a must offer requirement in the PJM Capacity Market. These imports could include pseudo tied units or resources with a grandfathered obligation. The external capacity that does not have a must offer requirement in the PJM Capacity Market is not obligated to serve PJM load under all conditions and therefore should not be assumed to be a source of capacity. This capacity should not be included in PJM's power flow calculations used to derive CETL values between PJM's LDAs. PJM has modified its CETL calculations to exclude such capacity.

---

[36] OATT Attachment DD § 6.5.

The MMU recommends that all capacity imports be required to be deliverable to PJM load in an identified LDA, zonal or subzonal, or defined combinations of specific zones, e.g. MAAC, prior to the relevant delivery year to ensure that they are full substitutes for internal, physical capacity resources. Pseudo ties alone are not adequate to ensure deliverability to PJM load. If capacity resources cannot be identified as deliverable to PJM load in an identified LDA, the import is not a capacity resource for PJM and should not be allowed. Simply attributing capacity imports to the Rest of RTO LDA does not constitute identifying the specific LDA that the resource is deliverable to. All internal capacity resources are deliverable to a specific LDA.

The MMU recommends that PJM implement a nodal capacity market in order to ensure that transmission constraints between and within LDAs and locational economic fundamentals are accurately reflected in capacity market prices. The MMU recommends that PJM clear the capacity market based on nodal capacity resource locations and the characteristics of the transmission system consistent with the actual electrical facts of the grid. The current nested LDA structure used in the capacity market does not adequately represent all the capacity transfers that are feasible among LDAs. For example, under the current structure, any capacity transfer between the Dominion LDA, which is modeled within the Rest of the RTO LDA, and the Pepco LDA, needs to pass through MAAC and SWMAAC LDAs, although Dominion and Pepco regions are linked by several transmission lines. In addition, the CETO/CETL analysis does not include transmission constraints internal to the modeled LDAs. Each LDA is modeled as a single node. Modeled LDAs can be quite large and internal transmission constraints can be significant. The absence of modeled internal constraints could result in the inability to deliver capacity from one part of an LDA to another part of an LDA.

The Indian River 4 Part V (RMR) status and payments were a direct result of not recognizing a transmission constraint internal to the LDA in the capacity market parameters. Another way of looking at the issue is that PJM should use the same reliability standard in capacity auctions as is used by PJM transmission planning. As in the case of Indian River 4, one result of the current design is that a unit may fail to clear in a BRA, decide to retire as a result, but then be found to be needed for reliability by PJM planning and paid under Part V of the OATT (RMR) to remain in service while transmission upgrades are made. Such a result means that the market design is flawed because PJM fails to recognize the transmission limits in the capacity market that it does recognize in transmission planning. Such a result means that the capacity market uses different reliability standards than transmission planning. That is inappropriate. The two standards should be the same.

The MMU recommends that PJM use a non-nested model with all LDAs modeled including VRR curves for all LDAs. Each LDA requirement should be met with the capacity resources located within the LDA and exchanges from neighboring LDAs up to

the transmission limit. LDAs should be allowed to price separate if that is the result of the LDA supply curves and the transmission constraints between LDAs.

The MMU recommends changing the RPM solution method to explicitly incorporate the cost of uplift payments in the objective function. Adoption of the additional MMU recommendation that all capacity offers be fully flexible, unless there is a physical reason for segments, would also significantly reduce or eliminate this problem.

The current form of the MOPR has no meaningful impact. The only function the MOPR is serving now is to create unnecessary administrative work in the application and compliance screening and to create barriers to entry for generation resources. Generation resources that miss a certification deadline to check a box that they are not receiving state conditioned support and will not exercise market power are then required to offer at uncompetitive net CONE levels or are not allowed to offer because the applicable MOPR floor exceeds the offer cap or no default MOPR floor for the technology is defined. Absent a meaningful change to MOPR, the MMU recommends eliminating the MOPR.

The MMU recommends that PJM require all market sellers of proposed generation capacity resources, including thermal and intermittent, to submit a binding notice of intent to offer at least six months prior to the base residual auction. This is consistent with the overall MMU recommendation that all capacity resources have a must offer obligation in the capacity market auctions. PJM has allowed such resources to meet their RPM must offer requirement with the offer of only 0.1 MW out of the total must offer MW. That interpretation is not consistent with the tariff or any reasonable approach to this rule. Failure to offer the resources can create unintended consequences for all market participants. That was the reason for this rule. The rule should be enforced as written and intended.

The MMU does not agree that a Planned Generation Resource that submitted a notice of intent (NOI) to offer can satisfy the RPM must offer requirement by offering 0.1 MW from a resource that is greater than 0.1 MW. As shown in the DPL-South case in the 2024/2025 BRA that prompted this rule change, inclusion of planned resources in the calculation of the planning parameters can have a significant impact on market outcomes that affect all market participants. Based on PJM's interpretation, a 500 MW planned resource that submits an NOI can offer just 0.1 MW in the auction and comply with the rule, creating a mismatch between the level of planned generation assumed in calculating the planning parameters and those included in supply. This is functionally equivalent to ignoring the rule. The amount of administrative work required for the application and compliance screening of the NOI rule is significant, and the rule does not come close to fixing the issue that it was meant to address. Absent rule changes to address this mismatch, the MMU recommends eliminating the NOI rule. The current application also results in an overall reduction of supply. The offer prerequisite of an NOI prevents the planned generation

that failed to submit an NOI from offering. The RPM must offer requirement for those that submitted NOIs is not being sufficiently enforced by only requiring a 0.1 MW offer.

The MMU recommends that all forecast data center load be excluded from capacity market auctions if it is not on line on June 1, 2026. Only organic load and existing data center load as of June 1, 2026, would be included in the capacity market auctions. PJM would operate a reliability auction for forecast data center load that has not signed or committed to sign a bilateral contract for capacity.[37]

Summary of Results

As shown in Table 13 and Table 14, the 134,478.1 MW of cleared generation and DR for the entire RTO, resulted in a reserve margin of 14.4 percent and a net deficit of 6,516.6 MW below the reliability requirement adjusted for FRR and PRD of 140,994.7 MW.[38] Net excess decreased 6,307.9 MW from a net deficit of 208.7 MW in the 2026/2027 RPM Base Residual Auction to a net deficit of 6,516.6 MW in the 2027/2028 RPM Base Residual Auction. As shown in Figure 2, the intersection of the supply curve and the downward sloping VRR demand curve resulted in a clearing price for Capacity Performance Resources of $333.44 per MW-day for the rest of RTO. These results do not include FRR entities.

Table 4 shows Generation Capacity Resources for which deactivation requests have been submitted which affected supply between the 2026/2027 BRA and the 2027/2028 BRA. If the deactivated resources that did not offer had been offered in the 2027/2028 RPM Base Residual Auction, there would have been no impact on the clearing prices. The 2027/2028 RPM Base Residual Auction cleared with a reserve shortfall of 6,516.6 MW (UCAP). The deficit of 6,516.6 UCAP MW is substantially higher than the UCAP equivalent of 1,871.2 ICAP MW of generation capacity that was deactivated between the 2026/2027 BRA and 2027/2028 BRA.

Market Design Issues

There are significant market design issues in the capacity market that result in material differences between the prices that result from the existing design and prices that would

---

[37] The details of the MMU's proposed design are included in two executive summaries: See "IMM Reliability Backstop Auction Design Proposal," (June 30, 2026) <https://www.monitoringanalytics.com/reports/Presentations/2026/IMM%20Backstop%20auction%20design%20proposal%20-%20V6%202026.06.19.pdf>. See also "IMM Curtailable Load Proposal," (June 30, 2026) <https://www.monitoringanalytics.com/reports/Presentations/2026/IMM%20Connect%20and%20Manage%20proposal%20-%20V2%202026.06.19.pdf>.

[38] These reserve margin calculations do not consider Fixed Resource Requirement (FRR) load.

result from a market design based on competitive market fundamentals including a consistent definition of capacity.

Competitive Offers

Effective for the 2018/2019 and subsequent delivery years through the 2022/2023 BRA, the default offer cap for Capacity Performance Resources was the applicable zonal net Cost of New Entry (CONE) times (B), where B is the average of the Balancing Ratios (B) during the Performance Assessment Intervals in the three consecutive calendar years that precede the Base Residual Auction for such delivery year. Effective for the 2023/2024 through the 2025/2026 Delivery Year, the offer cap is the net avoidable cost (ACR) of a capacity resource.

In a September 2, 2021, Order in Docket Nos. EL19-47-000, EL19-64-000, ER21-2444-000, and ER21-2877-000, the Commission reestablished a market seller offer cap (MSOC) equal to the net avoidable cost rate (ACR) that had been in place from the introduction of RPM capacity market model through the introduction of the CP modification, replacing the Net CONE times B offer cap.[39] The Commission's modified MSOC rules were applied in the 2025/2026 BRA. The Commission's MSOC order was appealed and the appeal was denied.

Effective for the 2018/2019 and subsequent delivery years, the ACR definition was modified to include two additional components, Avoidable Fuel Availability Expenses (AFAE) and Capacity Performance Quantifiable Risk (CPQR). AFAE is defined to include avoidable expenses related to fuel availability and delivery. CPQR is defined to be the quantifiable and reasonably supported cost of mitigating the risks of nonperformance that are assumed by Capacity Performance Resources when they submit an offer.

Effective with the 2026/2027 Delivery Year, the market seller offer cap definition was modified to include unit specific standalone Capacity Performance Quantifiable Risk (CPQR) and segmented unit specific offer caps.[40] For standalone CPQR, the offer cap is defined as the unit specific CPQR with no net revenue offset applied. For segmented unit specific offer caps, the capacity market seller can request that the first segment of the segmented unit specific offer cap be based on either unit specific standalone CPQR or net unit specific ACR. The remaining segments from the second segment up to the tenth segment are defined to be based on standalone CPQR.[41]

---

[39] 176 FERC ¶ 61,137 (September 2, 2021), *order on reh'g*, 178 FERC ¶ 61,121 (2022); *appeal denied*, Vistra Corp. v FERC, Case Nos 21-1214 et al (D.C. Cir August 15, 2023).

[40] 190 FERC ¶ 61,117 (2025).

[41] OATT Attachment DD § 6.4(e)

Allowing offers based on gross CPQR when net revenues are greater than total gross ACR, including CPQR, permits offers greater than the competitive level by allowing resources with a competitive offer of $0 per MW-day to make positive offers equal to one component of ACR, the gross CPQR component, ignoring net revenues entirely. The rule also permits offers greater than the competitive level by allowing resources with a competitive offer greater than $0 per MW-day but less than gross CPQR to make offers equal to one standalone component of ACR, the gross CPQR component, also ignoring EAS entirely.

The decision to allow segmented offer caps means allowing the exercise of market power. This is the case first because the segmented offer caps require that all avoidable costs be spread over a first MW segment that is smaller than the full resource, thus inflating the MSOC, and allow offer caps for all segments after the first segment based on gross CPQR with no net revenue offsets. If avoidable costs can be assigned to the first, self defined MW offer segment, and the later MW segments are not defined in the rules, MSOCs are meaningless. Assigning gross CPQRs and no net revenues to one or more undefined MW tail blocks would permit offers that exceed the correctly calculated MSOC by multiples and would permit the exercise of market power. The rule does not use any net revenue offset for the CPQR segments. The competitive level is defined as total gross avoidable costs, net of net revenues, divided by the total MW in the offer.

The MMU recommends elimination of the key remaining components of the CP model because they interfere with competitive outcomes in the capacity market and create unnecessary complexity and risk. The use of Net CONE as the basis for the penalty rate is unsupported by economic logic. The use of Net CONE to establish penalties is a form of arbitrary administrative pricing that creates arbitrarily high risk for generators, creates complexity in the calculation of CPQR and ultimately raises the price of capacity. Rather than penalizing capacity resources for nonperformance, capacity resources should be paid the daily price of capacity only to the extent that they are available to produce energy or provide reserves, as required by PJM on a daily/hourly basis, based on their cleared capacity (ICAP).[42] This is a positive performance incentive based on the market price of capacity rather than a penalty based on an arbitrary assumption. This would mean that capacity resources are paid to provide energy and reserves based on their full ICAP and are not paid a bonus for doing so. The reduced payments for capacity would directly reduce customers' bills for capacity. This would also end the pretense that there will be penalty payments to fund bonus payments. This would also end the need for complex CPQR calculations based on the penalty rate and assumptions about the number and

---

[42] See "Executive Summary of the IMM Capacity Market Design Proposal: Sustainable Capacity Market (SCM)," Independent Market Monitor for PJM (August 16, 2023) <http://www.monitoringanalytics.com/reports/Presentations/2023/IMM_RASTF-CIFP_SCM_Executive_Summary_20230816.pdf>.

timing of PAI. CP has not worked as the theory suggested. The Capacity Performance (CP) model was a failed experiment. The fundamental mistake of the CP design was to attempt to recreate energy market incentives in the capacity market. Winter Storm Elliott ("Elliot" or "WSE") provided the first real test of the CP design. Elliott showed that the CP design does not work and does not provide effective incentives. There was an extremely high forced outage level during Elliott despite the incentives and despite the fact that the effectively uncapped market seller offer cap (MSOC) was in place (Net CONE times B) for RPM auctions conducted for the 2022/2023 Delivery Year. In addition, it has been clear from prior, very brief and local PAI events that the process of defining excuses and retroactive replacement transactions is complex and very difficult to administer, and includes subjective elements. The multiple complaints filed against PJM and the associated settlement are both further evidence of the unworkability of the CP design.[43]

Avoidable Costs

The MMU recommends that the definition of avoidable costs in the tariff be corrected to be consistent with the economic definition. Avoidable costs are costs that are neither short run marginal costs, like fuel or consumables, nor fixed costs like depreciation and rate of return. Avoidable costs are the marginal costs of capacity and therefore the competitive offer level for capacity resources and therefore the market seller offer cap. Avoidable costs are the marginal costs of capacity whether a new resource or an existing resource.

The exact dividing line between fixed costs and avoidable costs is established by the tariff as one year. Avoidable costs are defined by the OATT to be the costs that a generation owner incurs as a result of operating a generating unit for one year, in particular the delivery year.[44] Conversely, but less intuitively, the tariff defines avoidable costs as the costs that a generation owner would not incur if the generating unit did not operate for one year, the delivery year. The two definitions produce identical results if applied correctly. Although the term mothball is used in the tariff to modify the term ACR, the term mothball is not defined in the tariff. In the ACR definition, mothball is an informal term better understood as a metaphor for the cost to operate for one year. Avoidable costs are the costs to operate the unit for one year, regardless of whether the unit plans to retire. Although the tariff includes different mothball and retirement values, the distinction is based on a misunderstanding of the meaning of avoidable costs and should be eliminated. PJM never explained exactly how it calculated mothball and retirement avoidable cost

---

43 *See* Offer of Settlement in the Winter Storm Elliott Complaints, Docket Nos. ER23-2975-000, EL23-53-000, et al. (September 29, 2023).

44 OATT Attachment DD § 6.8 (b).

levels. The tariff distinction between mothball and retirement avoidable costs is unsupported and should be eliminated.

The tariff also states that avoidable costs may also include annual capital recovery associated with investments required to maintain a unit as a Generation Capacity Resource, termed Avoidable Project Investment Recovery (APIR), despite the fact that these are not actually avoidable costs, particularly after the first year.

PJM arbitrarily modified the definition of avoidable costs effective April 15, 2019, to exclude major maintenance costs.[45] [46] [47] The result was to reduce gross ACR values includable in capacity market offers below actual gross ACR levels and to reduce offer caps in the capacity market below the competitive level. This change affected offer caps starting with the 2023/2024 BRA.

Net Revenues

On December 22, 2021, in Docket Nos. EL19-58-006 and ER19-1486-003, the Commission issued an order on voluntary remand, reversing a prior finding that PJM's reserves market rules are unjust and unreasonable. As part of that order, the Commission also reversed its determination that PJM should use a forward looking energy and ancillary services (E&AS) revenue offset and directed PJM to submit a compliance filing restoring the tariff provisions defining the E&AS revenue offset based on historical net revenues.[48] The MMU recommends the use of historical energy and ancillary services (E&AS) net revenue offset scaled using forward looking prices for energy prices and fuel costs.

The current PJM method for calculating forward looking E&AS net revenues includes an adjustment based on the prices of long term FTRs for the planning period closest in time to the delivery year which requires an adjustment for monthly average day-ahead congestion price differentials and an adjustment for loss component differentials of historical LMPs. Use of the adjustment based on the prices of long term FTRs adds unnecessary complexity, fails to make the result more accurate, makes the results less transparent, and in some cases make the results less accurate. PJM's use of long term FTRs in the forward energy market price calculation does not use the FTR auction for the

---

45 *PJM Interconnection L.L.C.*, Docket Nos. ER19-210-000 and EL19-8-000, Responses to Deficiency Letter re: Major Maintenance and Operating Costs Recovery (February 14, 2019).

46 167 FERC ¶ 61,030 (April 15, 2019).

47 OATT Attachment DD § 6.8 (c).

48 177 FERC ¶ 61,209 (2021); 179 FERC ¶ 61,104 (2022).

desired delivery year as a result of the timing of capacity auctions and FTR auctions when PJM is on its defined three year capacity market auction schedule.

On October 17, 2024, the Commission issued a final rule, Order No. 904, eliminating separate payments for reactive in all jurisdictional markets, including PJM.[49] As a result, effective with the 2026/2027 Delivery Year, reactive revenues are not included in the net revenue offset for RPM purposes including the VRR curve, market seller offer caps, and MOPR floor prices.[50] The result, holding everything else constant, was a higher VRR curve maximum price, higher market seller offer caps and higher MOPR floor prices.

CP Must Offer Requirement

Prior to the implementation of the capacity performance design, all capacity resources were subject to the must offer requirement. Nonetheless, and for reasons that remain unclear, effective for the 2018/2019 through 2025/2026 Delivery Years, intermittent resources, capacity storage resources, and hybrid resources consisting exclusively of components that in isolation would be intermittent resources or capacity storage resources were categorically exempt from the RPM must offer requirement. Capacity Storage Resources include hydroelectric, flywheel and battery storage. Intermittent Resources include wind, solar, landfill gas, run of river hydroelectric, and other renewable resources. PJM filed changes that were approved by FERC and included in the 2026/2027 BRA to adopt the MMU's recommendation to eliminate the categorical exemption to the RPM must offer requirement for all but demand resources. The categorical exemption for intermittent resources, capacity storage resources, and hybrid resources from the RPM must offer requirement was eliminated for all resources except demand resources in February 2025.[51]

There is no reason to exempt demand resources from the must offer requirement. The same rules should apply to all capacity resources.

The purpose of the must offer rule, which has been in place since the beginning of the capacity market in 1999, is to ensure that the capacity market works based on the inclusion of all demand and all supply, and to prevent the exercise of market power via withholding of supply. The purpose of the must offer requirement is also to ensure equal access to the

---

49 *Compensation for Reactive Power within the Standard Power Factor Range*, Order No. 904, 189 FERC ¶ 61,034 (2024) ("Order No. 904").

50 See Letter Order, FERC Docket No. ER25-682-001 (April 29, 2025).

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

transmission system through CIRs (capacity interconnection rights). If a resource has CIRs but fails to use them by not offering in the capacity market, the resource is withholding and is also denying the opportunity to offer to other resources that would use the CIRs. For these reasons, existing resources are required to return CIRs to the market within one year after retirement. The same logic should be applied to demand side resources. The failure to apply the must offer requirement will create increasingly significant market design issues and market power issues in the capacity market as the level of capacity from demand side resources remains high or increases. The capacity market was designed on the basis of a must buy requirement for load and a corresponding must offer requirement for capacity resources. The capacity market can work only if both are enforced.

In the 2027/2028 BRA, total reserves were 16,977.4 MW, which is 6,516.6 MW (UCAP) short of the required reserve level of 23,494.0 MW (UCAP). The sum of cleared MW of DR is 7,165.0 MW, or 42.2 percent of total reserves.

ELCC/Capacity Value of Capacity Resources

The units of measurement for the PJM capacity market auctions are unforced capacity (UCAP). PJM uses conversion factors to convert installed capacity MW (ICAP) into UCAP MW and this process is known as capacity accreditation. Prior to the 2023/2024 Delivery Year, EFORd values for thermal generators were used to convert ICAP to UCAP. Conversion factors for wind and solar generators were based on energy output during summer peak hours. Conversion factors for storage resources were equal to the maximum capability during 10 continuous hours of operation. The conversion factor for Demand Resources was equal to the forecast pool requirement (FPR). On July 30, 2021, FERC approved new PJM rules for defining/derating the capacity value of intermittent and storage resources, based on PJM's interpretation of the effective load carrying capability (ELCC) method.[52] PJM's average ELCC accreditations for intermittent and storage resources relied on the average capability by resource class for the 2023/2024 and 2024/2025 Delivery Years. Revisions, filed in October 2023, changed the capacity accreditation calculation to a marginal ELCC approach, applicable to all resource types. The PJM marginal ELCC approach was accepted by FERC in January 2024.[53] Capacity accreditation has been based on the revised marginal ELCC approach beginning with the 2025/2026 Delivery Year.

The MMU opposed PJM's ELCC rules because they relied on significant counterfactual behavioral assumptions for storage and demand response resources, used invented (putative) data for intermittent resources, were based on arbitrary historical periods, did

---

[52] See 176 FERC ¶ 61,056.

[53] 186 FERC ¶61,080 (January 30, 2024).

not recognize improvements in unit performance, were not locational, introduced significant volatility to the capacity accreditations and understated the winter capability of thermal resources.[54]

PJM's approach to ELCC is based on the correct high level insight that there is a need to calculate the availability of different resource types but the actual implementation does not do that correctly and results in a set of illogical outcomes. PJM's ELCC approach has a fundamental flaw. PJM's ELCC results are highly sensitive to the assumed resource mix, the comprehensive list of resources used in PJM's resource adequacy calculations. Because PJM does not update final ELCC values to reflect the actual resources that clear the auctions and receive capacity market obligation before the delivery year begins, these values are always based on assumptions that fail to match reality. PJM's approach does not evaluate actual hourly availability and provides no incentives related to actual hourly availability. For example, PJM assigned penalties to solar resources during Winter Storm Elliott in December 2022 when solar resources did not generate power after dark based on the explicit assumption that ELCC converted solar into a perfect resource. PJM's ELCC calculations rely on a significant overweighting of generator performance during the Polar Vortex in 2014 and Winter Storm Elliott in 2022 that results in artificially suppressed ELCC values for thermal resources and other resource types. This overweighting continues despite the fact that PJM has significantly changed its approach to extreme winter weather and implemented conservative operations. Unit performance has significantly improved as a result but those improvements have not been reflected in ELCC values. Despite poor performance observed from demand resource participants, PJM continues to assume unreasonably high performance from demand resources in the ELCC model. In the ELCC model, demand resources were assumed to become available immediately when needed and perform continuously without a limit on maximum number of contiguous performance hours. As a result of all these issues, the MMU has concluded that ELCC is not a viable method for determining the reliability contributions

[54] See Protest of the Independent Market Monitor for PJM, Docket ER24-99-000, et al. (November 9, 2023); Comments on Response to Deficiency Notice, Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER24-99-000 (December 21, 2023); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER24-99-000 (January 12, 2024); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER24-99-000 (January 24, 2024).

of capacity resources. The MMU has proposed a replacement for the PJM ELCC approach that is based on the actual hourly availability of all individual generators.[55] [56] [57]

Since the PJM marginal ELCC approach was accepted by FERC in January 2024, PJM has made a series of filings to change the impact of PJM's flawed ELCC accreditation design in ways that are not consistent with that design. PJM's April 14th filing removed the daily deficiency penalty for capacity market sellers that are short their capacity obligation due to a change in the ELCC rating between the base residual auction and final rating for the delivery year.[58] This change shifts the risk caused by ELCC ratings volatility from the generators to the load.[59] This change is not consistent with the ELCC design or basic market logic. FERC approved the rule change.[60]

PJM's ELCC calculations for demand resources have assumed that the full amount of offered demand resources (PLC – FSL) will be reduced when called. This unrealistic assumption was modified for the winter period, effective for the 2027/2028 delivery year. Under the revised approach, PJM reduces the expected demand resource response based

---

55 For additional details on the MMU proposal see "Executive Summary of the IMM Capacity Market Design Proposal: Sustainable Capacity Market (SCM)", Independent Market Monitor for PJM (August 16, 2023) <http://www.monitoringanalytics.com/reports/Presentations/2023/IMM_RASTF-CIFP_SCM_Executive_Summary_20230816.pdf>.

56 Any generation from a resource in excess of its CIR value is equivalent to generation from an energy only resource and should not be included in the calculation of the capacity value of the resource or in the calculation of the derated ELCC class ratings that define the capacity value of the resource. Updated rules beginning with the 2025/2026 Delivery Year require that ELCC accreditations exclude energy in excess of a generator's CIR. See 183 FERC ¶ 61,009 (April 7, 2023).

57 New rules beginning with the 2025/2026 Delivery Year correctly limit the delivered energy to the CIR level in the ELCC calculations. The new rules also include a complex transition process that allocates available headroom to intermittent resources with understated CIRs. The new rules apply to Delivery Year 2025/2026 BRA and subsequent delivery years. *See* 183 FERC ¶ 61,009 (April 7, 2023).

58 See PJM Filing, Docket No. ER25-2002-000 (April 14 2025).

59 See Comments of the Independent Market Monitor for PJM, Docket No. ER25-2002-000 (May 9, 2025); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER25-2002-000 (June 9, 2025); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER25-2002-000 (June 16, 2025).

60 See 191 FERC ¶61,203.

on the relationship between actual winter loads and the winter peak loads included in the demand resource capacity. Under the revised approach, aggregate winter nominated demand response capability is distributed across the 24 hour day using the normalized hourly load shape of registered demand response customers during the designated winter coincident peak period. The result is an improved estimate of available interruption capability during simulated winter reliability events and therefore an improved ELCC calculation for demand resources in the winter.[61]PJM continues to assume that demand resources will respond with 100 percent of the assumed reduction when called in the summer period.[62] Overall, PJM's calculations significantly overstate the ELCC of demand resources.

Additional efforts by PJM to make ad hoc amendments to the flawed ELCC approach were rejected by stakeholders. A range of changes were passed by the Effective Load Carrying Capability Senior Task Force (ELCCSTF) in July 2025 but failed to gain sufficient support at the August 20, 2025, Markets and Reliability Committee meeting.[63]

The MMU proposed alternative rules in the ELCCSTF to address the overweighting of winter performance embedded in PJM's approach. The MMU's approach would remove Winter Storm Elliot (WSE) and Polar Vortex 2014 from the historical performance data because they do not accurately represent expected generator performance. PJM demonstrated in Polar Vortex 2025 that PJM has significantly modified its approach to unit commitment and dispatch since Winter Storm Elliott (WSE). That change means that the generator performance during WSE is not a good predictor of expected generator performance. Inclusion of that data significantly overweights poor performance during specific events based on PJM approach that no longer applies and understates expected thermal resource performance.[64] The MMU proposal also required unit specific ELCC calculations for all resources and an accurate reflection of the higher winter output of

---

61 PJM, DR Availability Window: Proposed Solution Packages, <https://www.pjm.com/-/media/DotCom/committees-groups/committees/mc/2025/20250220/20250220-item-01---1-dr-availability-window-proposed-solution-packages---presentation.pdf> (February 20, 2025).

62 191 FERC ¶ 61,103 (2025).

63 See *Consent Agenda A – Draft MRC Minutes – 8.20.2025* at 2 in the PJM September 25, 2025 meeting materials for the PJM Markets and Reliability Committee.

64 *IMM Response to PJM ELCC Memo*, (July 25, 2025) <https://www.monitoringanalytics.com/reports/Presentations/2025/IMM_ELCCSTF_IMM_Response_20250725.pdf>.

unlimited resources in the resource adequacy and marginal ELCC calculations.[65] [66] The MMU approach was rejected by the ELCCSTF and these issues remain unaddressed.

Constraints in RPM Markets: CETO/CETL and LDA Reliability Requirements

Since the ability to import energy and capacity in LDAs may be limited by the existing transmission capability, PJM does a load deliverability analysis for each LDA.[67] The first step in this process is to determine the transmission import requirement into an LDA, called the Capacity Emergency Transfer Objective (CETO). This value, expressed in unforced megawatts (UCAP), is the transmission import capability required for each LDA to meet the area reliability criterion of loss of load expectation of one occurrence in 25 years when the LDA is experiencing a local capacity emergency. The CETO reflects both the forecasted load of the LDA and the reliability profile of the generation resources projected to be available for the delivery year. PJM considers all existing generation, plus planned generation resources that have completed Interconnection Service Agreements (ISAs). The reliability requirement of the LDA is defined as the CETO plus the total projected internal generation capacity.

The second step in the process is to determine the transmission import limit for an LDA, called the Capacity Emergency Transfer Limit (CETL), which is also expressed in unforced megawatts. The CETL is the ability of the transmission system to deliver energy into the LDA when it is experiencing the local capacity emergency used in the CETO calculation.

If CETL is less than CETO, transmission upgrades are planned under the Regional Transmission Expansion Planning (RTEP) Process. However, if transmission upgrades cannot be built prior to a delivery year to increase the CETL value, the lower level of CETL,

---

65 *IMM Proposal*, (June 30, 2025) <https://www.monitoringanalytics.com/reports/Presentations/2025/IMM_ELCCSTF_Proposal_20250630.pdf>.

66 *IMM Executive Summary of the IMM ELCC Proposal*, (July 9, 2025) <https://www.monitoringanalytics.com/reports/Presentations/2025/IMM_ELCCSTF_IMM_Executive_Summary_IMM_Proposal_20250711.pdf>.

67 "PJM Manual 14B: PJM Region Transmission Planning Process," § C.2.1.2 Locational Deliverability Areas, Rev. 59 (April 22, 2026). Manual 14B indicates that all "electrically cohesive load areas" are tested.

in combination with the internal LDA capacity resource supply curve, could result in larger locational price differences than if the CETL target were met.[68]

Under the Tariff, PJM determines, in advance of each BRA, whether specific Locational Deliverability Areas (LDAs) will be modeled in the auction, based on criteria which vary from clear to vague. PJM allows only modeled LDAs to price separate in an auction, regardless of the underlying fundamentals. Effective with the 2012/2013 Delivery Year, an LDA will be modeled as a potentially constrained LDA for a delivery year if the Capacity Emergency Transfer Limit (CETL) is less than 1.15 times the Capacity Emergency Transfer Objective (CETO), such LDA had a locational price adder in one or more of the three immediately preceding BRAs, or such LDA is determined by PJM in a preliminary analysis to be likely to have a locational price adder based on historic offer price levels. The rules also provide that starting with the 2012/2013 Delivery Year, EMAAC, SWMAAC, and MAAC LDAs will be modeled as potentially constrained LDAs regardless of the results of these three tests.[69] In addition, PJM may decide to model an LDA even if it does not qualify under these tests if PJM finds that "such is required to achieve an acceptable level of reliability."[70] A reliability requirement and a Variable Resource Requirement (VRR) curve are established for each modeled LDA.

The CETL levels and the CETL/CETO ratios directly affect but do not determine or predict whether there will be price separation for an LDA. Locational price differences result from the interaction between the CETL import limit, the demand for capacity in the LDA and the supply curve (MW and offer prices) for capacity both inside an LDA and outside the LDA. The CETL could be very low and there would be no price separation if all the offers for internal capacity that met the demand for capacity in the LDA were low compared to offers for capacity outside the LDA. The CETL could be very high (but less than the demand for capacity in the LDA) and there would be price separation if all the offers for internal capacity were high compared to offers for capacity outside the LDA.

The MMU recommends that PJM improve the clarity and transparency of its CETL calculations. CETL is a critical parameter that can have and has had significant impacts on capacity market outcomes. The changes in CETL that have affected market outcomes in this and prior auctions have not been well explained. Absent a fully nodal capacity

---

68 "PJM Manual 18: PJM Capacity Market," § 2.2 Role of Load Deliverability in the Reliability Pricing Model, Rev. 62 (Dec. 17, 2025).

69 Prior to the 2012/2013 Delivery Year, an LDA with a CETL less than 1.05 times CETO was modeled as a constrained LDA in RPM. No additional criteria were used in determining modeled LDAs.

70 OATT Attachment DD § 5.10 (a) (ii).

market clearing process, the MMU recommends that PJM use a non-nested model with all LDAs modeled including VRR curves for all LDAs. Each LDA requirement should be met with the capacity resources located within the LDA and exchanges from neighboring LDAs up to the transmission limit. LDAs should be allowed to price separate if that is the result of the individual LDA supply curves and the transmission constraints between LDAs. The MMU recommends that PJM implement a nodal capacity market in order to ensure that transmission constraints between and within LDAs and locational economic fundamentals are accurately reflected in capacity market prices.

The accuracy of the CETO calculation and reliability requirement of the LDA are based on the assumption that the planned generation capacity actually offers in the Base Residual Auction. Addition of a perfect generation resource with zero EFORD to an LDA would lower the CETO by the unforced capacity of the perfect generation resource. The reliability requirement of the LDA would remain unchanged even if the planned resources did not offer. If the planned generation that PJM assumed would be available for the delivery year in the CETO calculation fails to offer in the Base Residual Auction, the resulting decrease in the CETO is less than the resulting decrease in the derated offered supply in the situation where the planned generation is a disproportionately large share of load or has different seasonal characteristics assumed in the class average ELCC derated value. The net effect is an increase in the reliability requirement of the LDA expressed in unforced capacity MW that does not reflect the actual supply and demand fundamentals in the LDA and artificially higher clearing prices.

The MMU recommends that PJM require all market sellers of proposed generation capacity resources, including thermal and intermittent, to submit a binding notice of intent to offer at least six months prior to the base residual auction. This is consistent with the overall MMU recommendation that all capacity resources have a must offer obligation in the capacity market auctions.

The MMU does not agree that a Planned Generation Resource that submitted a notice of intent (NOI) to offer can satisfy the RPM must offer requirement by offering 0.1 MW from a resource that is greater than 0.1 MW. As shown in the DPL-South case in the 2024/2025 BRA that prompted this rule change, inclusion of planned resources in the calculation of the planning parameters can have a significant impact on market outcomes that affect all market participants. Based on PJM's interpretation, a 500 MW planned resource that submits an NOI can offer just 0.1 MW in the auction and comply with the rule, creating a mismatch between the level of planned generation assumed in calculating the planning parameters and those included in supply. This is functionally equivalent to ignoring the rule. The amount of administrative work required for the application and compliance screening of the NOI rule is significant, and the rule does not come close to fixing the issue that it was meant to address. Absent rule changes to address this mismatch, the MMU recommends eliminating the NOI rule. The current application also results in an overall reduction of supply. The offer prerequisite of an NOI prevents the planned generation

that failed to submit an NOI from offering. The RPM must offer requirement for those that submitted NOIs is not being sufficiently enforced by only requiring a 0.1 MW offer.

PJM should use the same reliability standard in capacity auctions as is used by PJM transmission planning. As in the case of Indian River 4, one result of the current design is that a unit may fail to clear in a BRA, decide to retire as a result, but then be found to be needed for reliability by PJM planning and paid under Part V of the OATT (RMR) to remain in service while transmission upgrades are made. Such a result means that the market design is flawed because PJM fails to recognize the transmission limits in the capacity market that it does recognize in transmission planning. Such a result means that the capacity market uses different reliability standards than transmission planning. That is inappropriate. The two standards should be the same.

CTRs

Capacity Transfer Rights (CTRs) are used to return capacity market congestion revenues to load. Load pays congestion. Capacity market congestion revenues are the difference between the total dollars paid by load for capacity and the total dollars received by capacity market sellers. The MW of CTRs available for allocation to LSEs in an LDA are equal to the Unforced Capacity imported into the LDA, less any MW of CETL paid for directly by market participants in the form of Qualifying Transmission Upgrades (QTUs) cleared in an RPM Auction, and Incremental Capacity Transfer Rights (ICTRs). There are two types of ICTRs, those allocated to a New Service Customer obligated to fund a transmission facility or upgrade and those associated with Incremental Rights-Eligible Required Transmission Enhancements.

PJM does not use the actual MW cleared in the BRA and three incremental auctions, the actual internal MW and the actual imported MW, when defining what customers pay and when defining the value of CTRs. Under the current rules, PJM defines the total MW needed for reliability in an LDA when clearing the BRA based on forecast demand at the time of the BRA. But PJM actually charges customers for the total MW needed for reliability based on forecast demand three years later, prior to the actual delivery year, and applies a zonal allocation. PJM also defines the internal capacity as the internal capacity after the final incremental auction conducted three years after the BRA, when auctions follow the traditional schedule. The difference between the updated MW needed for reliability and the updated internal capacity is the updated imported MW, adjusted for the final zonal allocation. In cases where the updated imported MW are smaller than the imported MW from the actual auction clearing, the total value of CTRs is lower that it would be if the actual auction clearing MW were used.

The actual load charges are allocated to each zone based on the ratio of the zonal forecast peak load to the RTO forecast peak load used for the third incremental auction conducted six months prior to the delivery year.

The CTR issue demonstrates a broader issue with capacity market clearing and settlements. The capacity market is cleared based on a three year ahead forecast of load and offers of capacity. Payments to capacity resources in the delivery year are based on the capacity market clearing prices and quantities. But payments by customers in the delivery year are not based on market clearing prices and quantities. Payments by customers in each zone are based on the ratio of zonal forecast peak load to the RTO forecast peak load used for the Third Incremental Auction, run six months prior to the delivery year when auctions follow the traditional schedule.[71] The allocation sometimes creates significant differences between the capacity cleared to meet the reliability requirement and the capacity obligation allocated to the customers in a zone. For example, ComEd Zone, which is identical to ComEd LDA cleared 27,932.1 MW including 5,574.0 MW of imports in the 2021/2022 RPM BRA. The ComEd Zone's capacity obligation, immediately after the clearing of the Base Residual Auction was 24,983.0 MW. The final ComEd Zone's capacity obligation for 2021/2022 Delivery Year after the Third Incremental Auction was 22,721.2 MW.

As with CTRs, the underlying reasons for not using the market clearing results to charge customers are not clear. Although not stated explicitly, the goal appears to be to reflect the fact that actual loads and forecast loads change between the auction and the delivery year. But the simple reallocation of capacity obligations based on changes in the load forecast does not reflect the BRA market results. The inclusion of speculative forecasts for data center load in PJM forecasts further distorts the results. The MMU recommends that the market clearing results be used in settlements rather than the reallocation process currently used.

Demand Side Resource Rules

DR capacity resources are, by default, designated as pre-emergency. A DR capacity resource may be designated as an emergency DR capacity resource if it is based on behind the meter generation that has environmental restrictions that limit operation to emergency conditions.[72] DR capacity resources do not have a must offer obligation in the energy market. DR capacity resources do not have a must offer obligation in the capacity market. The definition of performance for DR is not to provide a defined incremental level of MW when called but is only to be at a defined level of demand. DR capacity resources do not have a defined market seller offer cap or any market power mitigation rules. PJM does not include DR in its definition of primary or secondary reserves in the energy market. DR, for all these reasons, is an inferior resource in the capacity market. While calling on

---

71 See "PJM Manual 18: PJM Capacity Market," § 7.2.3 Final Zonal Unforced Capacity Obligations, Rev. 62 (Dec. 17, 2025).

72 OATT Attachment K, Section 8.5.

pre-emergency and emergency DR are defined to be Emergency Actions, PJM does not have clear rules defining when the operators must call on pre-emergency or emergency DR. Operators have discretion as to the order of implementing emergency procedures. Calling on emergency DR is part of the same step that requires PJM to declare a NERC Energy Emergency Alert Level 2.[73]

The level of DR products that buy out of their positions after the BRA means that the treatment of DR has a negative impact on generation investment incentives and that the rules governing the requirement to be a physical resource should be more clearly stated and enforced.[74] If DR displaces new generation resources in BRAs, but then buys out of the position prior to the delivery year, this means potentially replacing new entry generation resources at the high end of the supply curve with other existing but uncleared capacity resources available in Incremental Auctions at reduced offer prices. This suppresses the price of capacity in the BRA compared to the competitive result because it permits the shifting of demand from the BRA to the Incremental Auctions, which is inconsistent with the must offer, must buy rules, and the requirement to be an actual, physical resource, governing the BRA. PJM's sell back of capacity in Incremental Auctions exacerbates the incentive for DR to buy out of its BRA positions in IAs.

Demand Resources (DR) are interruptible load resources that are offered in an RPM Auction as capacity and receive the relevant LDA or RTO resource clearing price. Effective with the 2020/2021 Delivery Year, the Capacity Performance product includes two possible season types, annual and summer.

In Docket No. ER25-1525-000, FERC approved reforms to PJM's demand response program effective with the 2027/2028 Delivery Year.[75] The reforms included revised availability requirements for both Annual and Summer Period Demand Resources. Annual Demand Resources, which previously were required to be available only during specified summer and winter hours (10:00 a.m. to 10:00 p.m. EPT during June through October and the following May, and 6:00 a.m. to 9:00 p.m. EPT during November through April), must now be available to respond to PJM dispatch instructions 24 hours per day throughout the entire delivery year, unless there is a PJM approved maintenance outage

---

73 See "PJM Manual 13: Emergency Operations," § 2.3.2 Real-Time Emergency Procedures (Warnings and Actions), Rev. 97 (Nov. 20, 2025).

74 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <https://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).

75 191 FERC ¶ 61,103

during the November through April period. Summer Period Demand Resources must also be available 24 hours per day during the summer period rather than only during the former 10:00 a.m. to 10:00 p.m. EPT summer dispatch window.

The reforms also revise the calculation of Winter Peak Load (WPL), a key input to the ELCC accreditation methodology. Under the prior approach, each customer's WPL was based on the customer's highest noncoincident average hourly load on each of the five winter peak days. Under the revised approach, each customer's WPL is based on each customer's coincident load during the single system peak hour for each of the five winter peak days.

External Generation Resources/Capacity Imports

The establishment of a pseudo tie is one requirement for an external resource to be eligible to participate in the PJM Capacity Market. Pseudo tied external resources, regardless of their location, are treated as only meeting the reliability requirements of the rest of RTO and not the reliability requirements of any specific locational deliverability area (LDA). All imports offered in the auction from areas external to PJM are modeled as supply in the rest of RTO and not in any specific zonal or subzonal LDA. The fact that pseudo tied external resources cannot be identified as equivalent to resources internal to specific LDAs illustrates a fundamental issue with capacity imports. Capacity imports are not equivalent to, nor substitutes for, internal resources. All internal resources are internal to a specific LDA.[76]

Generation external to the PJM region is eligible to be offered into an RPM auction if it meets specific requirements.[77] [78] [79] Effective May 9, 2017, significantly improved pseudo tie

---

[76] External resources are not assigned to any of the five global LDAs or 22 zonal and subzonal LDAs. PJM's current practice is to model external resources in the rest of RTO. The practice is not currently documented by PJM. It was previously documented in "PJM Manual 18: PJM Capacity Market," § 2.3.4 Capacity Import Limits, Rev. 39 (December 21, 2017).

[77] See RAA Schedules 9 & 10.

[78] "PJM Manual 18: PJM Capacity Market," § 4.2.2 Existing Generation Capacity Resources – External, Rev. 62 (Dec. 17, 2025).

[79] "PJM Manual 18: PJM Capacity Market," § 4.6.4 Importing an External Generation Resource, Rev. 62 (Dec. 17, 2025).

requirements for external generation capacity resources were implemented.[80][81] [82] Any party to these pseudo tie agreements has the right to terminate upon forty-two (42) months' notice prior to the commencement of a delivery year, subject to receiving all necessary regulatory approvals. PJM also has the right to terminate such agreements with sixty (60) days' notice for defined reasons including negative impacts on reliability.[83]

The energy from all external generation resources that have an RPM commitment or FRR capacity plan commitment or that are designated as replacement capacity must be offered in the PJM Day-Ahead Energy Market at a MW level equal to their ICAP.[84]

Planned External Generation Capacity Resources are eligible to be offered into an RPM Auction if they meet specific requirements.[85] [86] Planned External Generation Capacity Resources are proposed Generation Capacity Resources, or a proposed increase in the capability of an Existing Generation Capacity Resource, that is located outside the PJM region; participates in the generation interconnection process of a balancing authority external to PJM; is scheduled to be physically and electrically interconnected to the transmission facilities of such balancing authority on or before the first day of the delivery year for which the resource is to be committed to satisfy the reliability requirements of the PJM Region; and is in full commercial operation prior to the first day of the delivery year.[87] An External Generation Capacity Resource becomes an Existing Generation Capacity

---

80 161 FERC ¶ 61,197 (2017).

81 Reimbursement Agreement for Pseudo-Ties <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/editable-reimbursement-agreement-for-pseudo-tie.ashx> (Accessed Oct 2, 2022).

82 OATT Attachment MM § 18 includes forms of pseudo tie agreements.

83 The conditions are defined at OATT Attachment MM § 18.

84 OATT Schedule 1 § 1.10.1A.

85 See RAA § 1.69A.

86 "PJM Manual 18: PJM Capacity Market," § 4.2.4 Planned Generation Capacity Resources – External, Rev. 62 (Dec. 17, 2025).

87 Prior to January 31, 2011, capacity modifications to existing generation capacity resources were not considered planned generation capacity resources. See 134 FERC ¶ 61,065 (2011).

Resource as of the earlier of the date that interconnection service commences or the resource has cleared an RPM Auction for a prior delivery year.[88]

Minimum Offer Price Rule (MOPR)

On June 29, 2018, the Commission initiated an FPA section 206 proceeding to address the price suppressive impact of resources receiving out of market support.[89] The Commission issued revised MOPR rules on December 19, 2019.[90] The rules approved in the December 19, 2019, order defined state subsidy and expanded the applicability of the MOPR to any new or existing resource that received a state subsidy, and retained the applicability of MOPR to new gas-fired resources.[91] The Commission's resultant modified MOPR rules were applied in the 2022/2023 BRA.

On July 30, 2021, PJM filed tariff changes to effectively eliminate the MOPR while creating a confusing and inefficient administrative process that effectively makes it both unnecessary and impossible to prove buyer side market power as PJM defined it.[92] [93] [94] On September 29, 2021, PJM's proposed MOPR changes took effect by operation of law based on a tie vote at the Commission and the rules governing tie votes.[95] This MOPR approach was applied in the 2024/2025 through 2027/2028 BRAs.

---

88 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation. See 134 FERC ¶ 61,065 (2011).

89 163 FERC ¶ 61,236 (2018) at 5 and 6.

90 169 FERC ¶ 61,239 (2019), *order denying reh'g*, 171 FERC ¶ 61,035 (2020).

91 OATT Attachment DD § 5.14(h).

92 *Revisions to Application of Minimum Offer Price Rule*, PJM Interconnection L.L.C., ER21-2582-000 (July 30, 2021).

93 *Protest of the Independent Market Monitor for PJM*, Monitoring Analytics, LLC, ER21-2592-000 (August 20, 2021).

94 *Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM*, Monitoring Analytics, LLC, ER21-2592-000 (September 22, 2021).

95 See Notice of Filing Taking Effect by Operation of Law, Docket No. ER21-2582-000 (September 29, 2021); Notice of Denial of Rehearing Denied by Operation of Law, 177 FERC ¶ 62,105 (2021); *aff'd*, PJM Power Providers Group v. FERC, Case Nos. 21-3068 et al. (3rd Cir. January 24, 2024).

The revised MOPR in OATT Attachment DD § 5.14(h-2) is effective for RPM auctions for the 2023/2024 and subsequent delivery years. Under the revised MOPR, a generation resource would be subject to an offer floor if the capacity is deemed to meet the definition of Conditioned State Support or if the capacity market seller plans to use the resource to exercise Buyer-Side Market Power as the term is defined in the tariff through either self certification or a fact specific review initiated by the MMU or PJM. Whether a state program or policy qualifies for Conditioned State Support would be the result of a Commission determination.

The MMU's filing in response to PJM's proposal was clear. The PJM markets would be better off, more competitive, and more efficient with no MOPR than with PJM's proposed approach. PJM's proposal effectively eliminates the MOPR while creating a confusing and inefficient administrative process that effectively makes it both unnecessary and impossible to prove buyer side market power as PJM has defined it.[96]

Seasonal Capacity

Effective for the 2018/2019 and subsequent delivery years, the RPM market design incorporated seasonal capacity resources.[97] [98]

For the 2027/2028 BRA, summer period capacity performance resources may include summer period demand resources, capacity storage resources, intermittent resources, and environmentally limited resources that have an average expected energy output during the summer peak hour periods consistently and measurably greater than their average expected energy output during winter peak hour periods.[99] This tariff language is vague and includes no actual metrics.

Winter period capacity performance resources may include capacity storage resources, intermittent resources, and environmentally limited resources that have an average

---

96 See Protest of the Independent Market Monitor for PJM, Docket No. ER21-2582-000 (August 20, 2021); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER21-2582-000 (September 22, 2021).

97 158 FERC ¶ 62,220.

98 See Comments of the Independent Market Monitor for PJM, Docket No. ER17-367-000 (December 8, 2016).

99 OATT Attachment DD § 5.5A(e)(i).

expected energy output during winter peak hour periods consistently and measurably greater than its average expected energy output during summer peak hour periods.[100]

Generation owners of intermittent resources and environmentally limited resources can request winter capacity interconnection rights (CIRs). If the intermittent resource or environmentally limited resource is deemed deliverable by PJM based on the additional CIRs, the generation owner is granted the additional CIRs for the winter period of the relevant delivery year at a zero cost. Winter seasonal products have the ability to inject more MW in the winter because the lower peak loads in the winter allow higher injections from certain resources without needing any additional network upgrades. But this system capacity in the winter is already paid for by resources that applied for needed network upgrades to inject in the summer to meet the annual peak loads that are expected to occur in the summer.

PJM's practice of giving away winter CIRs, that appear to be available because other resources paid for the supporting network upgrades, requires annual capacity resources to subsidize the interconnection costs of intermittent resources and artificially increases the capacity value of the winter resources. Those CIRs are not available to be sold to or provided to intermittent resources because they have been paid for by annual resources. The MMU recommends that PJM require all market participants to meet their deliverability requirements under the same rules.

RPM rules allow for the matching of complementary seasonal products across LDAs. Capacity market sellers are able to combine intermittent resources, capacity storage resources, demand resources, or environmentally limited resources to create an aggregate resource regardless of physical or electrical proximity. Rules permitting market participants to aggregate resources located in the smallest modeled LDA common to the underlying aggregated resources became effective in the 2020/2021 Delivery Year. The capacity performance rules permit aggregation across LDAs.[101] The capacity performance rules also permit capacity market sellers to offer standalone summer or winter resources and the auction clearing optimization matches and clears equal quantities of summer and winter resources from different sellers, also across LDAs.

The MMU recommends that the market rules not permit the matching of seasonal generation with demand resources. Demand resources are not the equivalent of generating resources.

---

[100] OATT Attachment DD § 5.5A(e)(ii).

[101] OATT Attachment DD § 5.12(a).

Summer period capacity resources and winter period capacity resources located in the same LDA are cleared in equal quantities to satisfy the resource requirement of the LDA in which they are both located. The seasonal products that do not clear in the same LDA are then matched with complementary seasonal products located in the parent LDA. This could result in very different physical and electrical locations, for example for summer and winter resources located in distant LDAs that are both part of the rest of RTO LDA. Regardless, during PAI, seasonal products are required to deliver in the LDA where they are physically located.

There is no reason to have such complex rules for combining seasonal products. PJM is a locational market. The current seasonal rules are not consistent with PJM's nodal and locational market design. Any combined seasonal products should be in the same LDA and preferably at the same location, in order for the energy market and capacity market to remain synchronized and reliability metrics correctly calculated.

The seasonal matching rules increase uplift payments that may include the exercise of market power when seasonal products that offer at prices higher than the clearing price clear the auction when paired with complementary seasonal products from other LDAs.

For example, an offer for summer capacity in PSEG could be matched with an offer for winter capacity in DEOK, and the two offers would receive the price corresponding to the lowest common parent LDA. In this example, the only common parent LDA of PSEG and DEOK is RTO, so the combined offer would receive the RTO clearing price. A winter resource in the PSEG LDA offered for $200 per MW-day that is matched with a summer resource in the DEOK LDA offered for $50 per MW-day would clear in the common parent LDA, rest of RTO, if the clearing price of the common parent LDA is greater than or equal to $125 per MW-day (the average of the two offers). The winter resource in the ComEd LDA would be paid uplift based on the difference between the clearing price and its standalone offer price, regardless of whether that offer was at a competitive level.

The current RPM market rules apply market power mitigation only to sell offers that would increase the market clearing price but do not address increases in uplift that result from complementary seasonal offers at greater than competitive levels. The RPM market rules permit the exercise of market power for market participants that receive seasonal uplift payments.

The MMU recommends that the RPM market power mitigation rules be modified to apply offer caps in all cases when the three pivotal supplier test is failed and the sell offer is greater than the offer cap in order to ensure that market power does not result in an increase in uplift payments for seasonal products.

Market Clearing Model

The nested structure of the capacity market design also contributes to an important inefficiency in the clearing of resources. Under the existing nested structure, every resource is eligible to satisfy the reliability requirement of the local LDA where the resource is located but is also eligible to satisfy the reliability requirement of all the higher level parent LDAs to which it belongs. For example, a resource located within the PSEG North LDA can satisfy the reliability requirement of PSEG North, of PSEG, of EMAAC, of MAAC and of the RTO. The problem arises because the LDA demand (VRR) curves are defined such that, in the optimization, any resource that satisfies the reliability requirement of a higher level LDA results in a larger consumer surplus than clearing that resource in a lower level LDA. The goal of the optimization is to maximize consumer surplus. For example, a capacity resource located in the child LDA PSEG North always results in a higher or equal consumer surplus if it clears to meet the parent LDA PSEG's requirement compared to clearing to meet PSEG North's requirement. As a result, the apparently optimal clearing solution would satisfy the parent LDA's requirement while clearing fewer resources to satisfy the child LDA's requirement. In order to ensure that the requirements of child LDAs are satisfied before the requirements of parent LDAs and therefore to ensure local reliability, the nesting based clearing process used by PJM requires iteratively solving a series of optimizations.[102] This clearing process always produces a solution with a lower consumer surplus by satisfying the child LDA's requirement before satisfying parent LDA's requirement. With this iterative solving, the clearing process may also result in implausible outcomes such as lower prices from a reduction in supply. Absent a fully nodal capacity market clearing process, the MMU recommends that PJM use a non-nested model with all LDAs modeled including VRR curves for all LDAs.

PJM's market clearing algorithm does not include uplift payments in the objective function, resulting in a less accurate and less efficient result.[103] In RPM auctions, capacity market sellers are allowed to specify a minimum level of unforced capacity for any resource offered into the auction rather than a fully flexible offer. If any such inflexible offers are marginal or close to marginal, PJM's market solution algorithm relaxes the minimum level on those offers and reruns the optimization, allowing those offers to clear below the specified minimum level. Any resource that, as a result, cleared at a MW level below the specified minimum level, is paid uplift for the difference between the cleared MW and the minimum level, at the clearing price.

---

[102] For more details on the clearing process, see Attachment A.

[103] For more details on these recommendations, see Attachment A.

If the market clears on a nonflexible sell offer segment, a sell offer that specifies a minimum block MW value greater than zero, the capacity market seller will be assigned uplift MW equal to the difference between the sell offer minimum block MW and the sell offer cleared MW quantity if that solution to the market clearing minimizes the cost of satisfying the reliability requirements across the PJM region.[104] The uplift payment for partially cleared resources equals the uplift MW times the clearing price. A more efficient solution could include not selecting a nonflexible segment from a lower priced offer and accepting a higher priced sell offer that does not include a minimum block MW requirement.[105] [106]

The clearing optimization employed by PJM is not equipped to evaluate the tradeoff between selecting an inflexible segment and paying the associated uplift payment versus selecting an expensive flexible segment and not paying the uplift payment. This is because the solution method does not consider the additional cost of uplift payments as part of the objective function of the optimization. The alternative to clearing an inflexible offer will generally be clearing a higher priced offer to satisfy the applicable resource requirements without an uplift payment. In the MMU's approach, the market clearing algorithm explicitly compares solutions with uplift against solutions without uplift to arrive at the optimal solution. The MMU recommends changing the RPM solution method to explicitly incorporate the cost of uplift payments in the objective function. Adoption of the additional MMU recommendation that all capacity offers be fully flexible, unless there is a physical reason for segments, would also significantly reduce or eliminate this problem.

For the second time since the introduction of the RPM capacity market design, the 2027/2028 BRA used a VRR curve with a defined minimum price. The VRR curves have always had a defined maximum price that served as a shortage price and a limit on the exercise of market power. The minimum price introduced additional complexity to the clearing with the nested VRR curve structure. The minimum price is enforced by forcing the child LDAs to clear only the resources that were offered above or equal to the minimum price. The horizontal segment set at the minimum price for the Rest of RTO VRR curve was extended to a sufficiently large UCAP MW quantity to ensure that the clearing price remains at or above the minimum price (see Figure 1). Table 22 shows the price coordinates for the 2027/2028 RPM BRA actual VRR curve for the RTO and every

---

104 OATT Attachment DD § 5.14(b).

105 OATT Attachment DD § 5.12(a).

106 For more details, see Attachment A.

modeled LDA. Table 23 shows the price coordinates for the 2027/2028 RPM BRA unrestricted VRR curve for the RTO and every modeled LDA.

MMU Review

The MMU reviewed inputs to and results of the 2027/2028 RPM Base Residual Auction:[107]

- Unit Specific Market Seller Offer Caps. Verified that the avoidable costs (ACR), including avoidable fuel availability expenses and risk adders, and opportunity costs used to calculate offer caps were reasonable and properly documented;
- Net Revenues. Calculated historic unit specific net revenue from PJM energy and ancillary service markets for each PJM Generation Capacity Resource for the three year period from 2022 through 2024;[108]
- Minimum Offer Price Rule (MOPR). Reviewed requests for Unit Specific Exceptions and verified MOPR applicability and mitigation;
- Offers of Planned Generation Capacity Resources. Reviewed sell offers for Planned Generation Capacity Resources to determine if consistent with levels specified in Tariff;
- Notice of Intent to Offer (NOI). Verified that all offers for Planned Generation Capacity Resources had provided an NOI;
- Exported Resources. Verified that Generation Capacity Resources exported from PJM had financially and physically firm external contracts or made documented and reasonable opportunity cost offers and identified any failures to comply with rules;
- RPM Must Offer Requirement. Reviewed exceptions to the RPM must offer requirement, reviewed unoffered capacity for Existing Generation Capacity Resources and Planned Generation Capacity Resources with NOIs, conducted the five percent Zonal Capacity Price impact test for unexcused capacity that failed to offer;
- CP Must Offer Requirement. Reviewed exceptions to the CP must offer requirement;

---

[107] Unless otherwise specified, all volumes and prices are in terms of unforced capacity (UCAP), which is calculated as installed capacity (ICAP) times accredited UCAP factor for generation resources and ICAP times demand resource ELCC class rating for DR.

[108] Net revenue values for the 2027/2028 RPM BRA were calculated consistent with the PJM market rules effective at the time. See 178 FERC ¶ 61,122 (2022).

- CP Eligibility. Reviewed documentation for Intermittent Resources and Capacity Storage Resources to support CP eligibility.

- Removal from Capacity Resource Status. Reviewed requests for removal from capacity resource status and to be energy only;

- FRR. Verified FRR sales caps and threshold quantities;

- Clearing Prices. Verified that the auction clearing prices were accurate, based on submitted offers and the Variable Resource Requirement (VRR) curves; [109]

- Market Structure Test. Verified that the market power test was properly defined using the TPS test, that offer caps were properly applied and that the TPS test results were accurate.

Market Power Tests

All participants in the RTO market failed the TPS test (Table 1).[110] The result was that offer caps were applied to all sell offers for Existing Generation Capacity Resources when the capacity market seller failed the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would have increased the market clearing price. Market power mitigation was applied to 47 Capacity Performance sell offers. The MMU calculated unit specific ACR based offer caps for only 14 generation resources (1.0 percent) of the 1,351 generation capacity resources offered.

The Commission's order effective September 2, 2021, required the use of offer caps equal to net ACR.[111] Market power mitigation was not applied to any Capacity Performance sell offers of generation capacity resources in the 2022/2023 or 2021/2022 RPM Base Residual Auctions as a result of the fact that the Net CONE times B offer cap applied in those auctions exceeded the competitive level. The purpose of market power mitigation is to produce competitive results despite the endemic structural market power in the capacity market. The Net CONE times B offer cap assumed competition where it did not exist and

---

[109] Attachment A reviews the MMU calculation of auction outcomes.

[110] See the MMU *Technical Reference for PJM Markets,* at "Three Pivotal Supplier Test" for a more detailed discussion of market structure tests.

[111] See 176 FERC ¶ 61,137 (2021), *reh'g denied*, 178 FERC ¶ 61,121 (2022).

led to noncompetitive outcomes resulting in customers being overcharged by a combined $1.454 billion in the 2021/2022 and 2022/2023 BRAs.[112]

In applying the three pivotal supplier market structure test, the relevant supply for the RTO market includes all supply from generation resources offered at less than or equal to 150 percent of the RTO clearing price resulting from offer capped offers for all supply.[113] The relevant supply for the constrained LDA markets includes the incremental supply from generation resources inside the constrained LDAs which was offered at a price higher than the unconstrained clearing price for the parent LDA market and less than or equal to 150 percent of the clearing price for the constrained LDA resulting from offer-capped offers for all supply. The relevant demand consists of the incremental MW needed in the LDA to relieve the constraint and meet the VRR curve for the LDA.

Table 1 presents the results of the TPS test and the one pivotal supplier test. A generation owner or owners are pivotal if the capacity of the owners' generation facilities is needed to meet the demand for capacity. The results of the TPS are measured by the Residual Supply Index (RSI_3). The RSI_x is a general measure that can be used with any number of pivotal suppliers. The TPS test uses three pivotal suppliers. The subscript denotes the number of pivotal suppliers included in the test. If the RSI_x is less than or equal to 1.0, the supply owned by the specific generation owner, or owners, is needed to meet market demand and the generation owners are pivotal suppliers with a significant ability to influence market prices. If the RSI_x is greater than 1.0, the supply of the specific generation owner or owners is not needed to meet market demand and those generation owners have a reduced ability to unilaterally influence market price.[114] If the RSI_x is equal to 0.0, there is only one supplier and that supplier is a monopoly.

---

[112] See "Analysis of the 2021/2022 RPM Base Residual Auction - Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018) and "Analysis of the 2022/2023 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20222023_RPM_BRA_20220222.pdf>.

[113] Effective November 1, 2009, DR and EE resources are not included in the TPS test. See 129 FERC ¶ 61,081 (2009) at P 31. Effective with the 2026/2027 Deliver Year, EE resources no longer participate in the PJM Capacity Market. See 189 FERC ¶ 61,095 (November 5, 2024).

[114] The market definition used for the TPS test includes all offers with costs less than or equal to 1.50 times the clearing price. The appropriate market definition to use for the one pivotal supplier test includes all offers with costs less than or equal to 1.05 times the clearing price. See the MMU *Technical Reference for PJM Markets*, at "Three Pivotal Supplier Test" for additional discussion.

Table 1 RSI results: 2027/2028 RPM Base Residual Auction[115]

	$RSI_{1\ 1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
RTO	0.82	0.63	155	155

Offer Caps and Offer Floors

The defined Generation Capacity Resource owners were required to submit offer cap requests by 120 days prior to the 2027/2028 RPM Base Residual Auction.[116] Market power mitigation measures are applied to Existing Generation Capacity Resources such that the sell offer is set equal to the tariff defined offer cap when the capacity market seller fails the market structure test for the auction, the submitted sell offer exceeds the tariff defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price.[117]

Avoidable costs are the costs that a generation owner incurs as a result of operating the generating unit for one year, in particular the delivery year.[118] As a result, the tariff defines avoidable costs as the costs that a generation owner would not incur if the generating unit did not operate in the delivery year. Avoidable cost-based offer caps are defined to be net of revenues from all other PJM markets and unit specific bilateral contracts and expected bonus performance payments/nonperformance charges. Capacity resource owners could provide ACR data by providing their own unit specific data or, for auctions for delivery years prior to 2020/2021 and auctions held after September 2, 2021, by selecting the default ACR values. The specific components of avoidable costs are defined in the PJM Tariff.[119]

Effective for the 2018/2019 and subsequent delivery years, the ACR definition includes two additional components, Avoidable Fuel Availability Expenses (AFAE) and Capacity Performance Quantifiable Risk (CPQR).[120] AFAE is defined to include avoidable expenses

---

115 The RSI shown is the lowest RSI in the market.

116 The deadline for data submission changed from two months prior to the auction to 120 days prior to the auction, effective December 17, 2012, by letter order in FERC Docket No. ER13-149-000 (November 28, 2012).

117 OATT Attachment DD § 6.5.

118 OATT Attachment DD § 6.8(b).

119 OATT Attachment DD § 6.8(a).

120 151 FERC ¶ 61,208.

related to fuel availability and delivery. CPQR is available for Capacity Performance Resources. CPQR is defined to be the quantifiable and reasonably supported cost of mitigating the risks of nonperformance associated with submission of an offer.

Effective for the 2022/2023 Delivery Year, the ACR definition excludes major maintenance costs if these costs had been previously included in unit specific ACR by a capacity market seller or effective with the 2020/2021 Delivery Year if these costs had not been previously included in unit specific ACR by a capacity market seller.[121] [122]

Effective with the 2026/2027 Delivery Year, the market seller offer cap definition was modified to include unit specific standalone Capacity Performance Quantifiable Risk (CPQR) and segmented unit specific offer caps.[123] For standalone CPQR, the offer cap is defined as the unit specific CPQR with no net revenue offset applied. For segmented unit specific offer caps, the capacity market seller can request that the first segment of the segmented unit specific offer cap be based on either unit specific standalone CPQR or net unit specific ACR. The remaining segments from the second segment up to the tenth segment are defined to be based on standalone CPQR.[124]

The opportunity cost option for exports allows capacity market sellers to provide a documented price available for a PJM generation resource in a market external to PJM, net of transmission costs, subject to export limits. If the relevant RPM market clears at or above the opportunity cost, the Generation Capacity Resource is sold in the RPM market. If the opportunity cost is greater than the clearing price the Generation Capacity Resource does not clear in the RPM market and it is available to sell in the external market.

As shown in Table 2, 1,351 generation resources submitted Capacity Performance offers in the 2027/2028 RPM Base Residual Auction. Of the 1,351 offers, 99.0 percent were based on default ACR, were price takers, or were uncapped planned resources. Only 1.0 percent of offers (14 generation resources) requested unit specific review, of which 0.0 percent were for standalone CPQR, 0.5 percent were for unit specific ACR review, and 0.5 percent were for unit specific opportunity cost review. Two resources of those 14 did not reach agreement with the MMU. The MMU calculated offer caps for 943 generation resources that submitted capacity offers. Unit specific ACR based offer caps were calculated for 7 generation resources (0.5 percent), of which 0 resources (0.0 percent) requested a CPQR.

---

[121] 167 FERC ¶ 61,030 (April 15, 2019).

[122] OATT Attachment DD § 6.8 (c).

[123] 190 FERC ¶ 61,117 (2025).

[124] OATT Attachment DD § 6.4(e).

Of the 1,351 generation capacity resources offered, 929 generation resources (68.8 percent) had default ACR based offer caps, 7 generation resources (0.5 percent) had unit specific ACR based offer caps, 0 generation resources (0.0 percent) had standalone CPQR based offer caps, 7 generation resources (0.5 percent) had opportunity cost based offer caps, 45 Planned Generation Capacity Resources (3.3 percent) had uncapped offers, while the remaining 363 generation resources (26.9 percent) were price takers.

Market power mitigation measures are applied to capacity resources subject to MOPR such that the sell offer is set equal to the MOPR Floor Offer Price when the submitted sell offer is less than the MOPR Floor Offer Price and an exception was not granted, or the sell offer is set equal to the agreed upon minimum level of sell offer when the sell offer is less than the agreed upon minimum level of sell offer based on a unit specific exception. As shown in Table 3, there were unit specific exception requests for 0.0 MW for MOPR under OATT Attachment DD § 5.14(h-2). Of the 1,788.3 MW offered that were subject to MOPR, 1,740.1 MW cleared and 48.2 MW did not clear.

On September 29, 2021, PJM's proposed MOPR changes took effect by operation of law.[125] The MOPR changes modified the MOPR applicability rules and replaced it with an effectively meaningless MOPR screen.[126] The only reason that any capacity resources were subject to MOPR review in the 2027/2028 BRA was that the resources missed the MOPR certification deadline.[127]

---

[125] See Notice of Filing Taking Effect by Operation of Law, Docket No. ER21-2582-000 (September 29, 2021); Notice of Denial of Rehearing Denied by Operation of Law, 177 FERC ¶ 62,105 (2021); *appeal pending*, PJM Power Providers Group v. FERC, Case Nos. 21-3068 et al. (3rd Cir.).

[126] See Protest of the Independent Market Monitor for PJM, Docket No. ER21-2582-000 (August 20, 2021); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER21-2582-000 (September 22, 2021).

[127] See OATT Attachment DD § 5.14(h-2).

Tables for Offer Caps and Offer Floors

Table 2 ACR statistics: 2027/2028 RPM Base Residual Auction

Offer Cap/Mitigation Type	Number of Generation Resources Offered	Percent of Generation Resources Offered
Default ACR	929	68.8%
Unit specific ACR (APIR)	6	0.4%
Unit specific ACR (APIR and CPQR)	0	0.0%
Unit specific ACR (non-APIR)	1	0.1%
Unit specific ACR (non-APIR and CPQR)	0	0.0%
Unit specific standalone CPQR	0	0.0%
Unit specific segmented offer caps	0	0.0%
Opportunity cost	5	0.4%
Default ACR and opportunity cost	2	0.1%
Uncapped planned uprates and default ACR	0	0.0%
Uncapped planned uprates and opportunity cost	0	0.0%
Uncapped planned uprates and price taker	0	0.0%
Uncapped planned generation resources	45	3.3%
Existing generation resources as price takers	363	26.9%
Total Generation Capacity Resources offered	1,351	100.0%

Table 3 MOPR statistics: 2027/2028 RPM Base Residual Auction

			ICAP (MW)			UCAP (MW)	
MOPR Type	Calculation Type	Number of Requests	Requested	MMU Agreed	Offered	Offered	Cleared
OATT Attachment DD § 5.14(h-2)	Unit Specific Exception	0	0.0	0.0	0.0	0.0	0.0
OATT Attachment DD § 5.14(h-2)	Default	NA	NA	NA	3,097.7	1,788.3	1,740.1
Total		0	0.0	0.0	3,097.7	1,788.3	1,740.1

Generation Capacity Resource Changes

As shown in Table 2, Capacity Performance offers were submitted for 1,351 generation resources in the 2027/2028 RPM Base Residual Auction, compared to 1,293 generation resources offered in the 2026/2027 RPM Base Residual Auction, a net increase of 58 generation resources. This was a result of 91 additional generation resources offered, offset by 33 fewer generation resources offered.

The 91 additional generation resources offered consisted of 43 new resources (393.8 MW), 25 resources that were unoffered in the 2026/2027 BRA (223.3 MW), 6 resources that were previously entirely FRR committed (375.2 MW), and 17 additional resources due to winter modeling changes.[128]

[128] Unless otherwise specified, all volumes and prices are in terms of UCAP.

The 43 new Generation Capacity Resources consisted of 41 solar resources (262.1 MW), 3 wind or battery storage resources (131.7 MW).

The 33 fewer generation resources offered consisted of 9 deactivated resources (1,229.7 MW), 7 additional resources fully committed to FRR (268.0 MW), 5 resources (760.4 MW) not offered and not excused, 4 resources excused from offering for other reasons (410.2 MW), and 8 fewer resources due to winter modeling changes and aggregation of RPM resources. Table 4 shows Generation Capacity Resources for which deactivation requests have been submitted which affected supply between the 2026/2027 BRA and the 2027/2028 BRA. If the deactivated resources that did not offer had been offered in the 2027/2028 RPM Base Residual Auction, there would have been no impact on the clearing prices. The 2027/2028 RPM Base Residual Auction cleared with a reserve shortfall of 6,516.6 MW (UCAP). The deficit of 6,516.6 UCAP MW is substantially higher than the UCAP equivalent of 1,871.2 ICAP MW of generation capacity that was deactivated between the 2026/2027 BRA and 2027/2028 BRA.

Table 4 Generation Capacity Resource deactivations[129]

Resource Name	LDA	ICAP (MW)	Date Deactivation Notice Submitted	Projected or Actual Deactivation Date
CUMBERLAND CT	EMAAC	78.5	28-Jan-25	01-Jun-27
SHERMAN AVENUE CT 1	EMAAC	78.8	28-Jan-25	01-Jun-27
FORKED RIVER C-1	JCPL	34.0	25-Feb-25	01-Jun-26
FORKED RIVER C-2	JCPL	31.0	25-Feb-25	01-Jun-26
ROCKFORD CT 11	ComEd	179.1	01-May-25	31-Dec-29
ROCKFORD CT 12	ComEd	177.8	01-May-25	31-Dec-29
ROCKFORD CT 21	ComEd	180.0	01-May-25	31-Dec-29
KINCAID COAL 1	ComEd	556.0	22-Jul-25	30-Nov-27
KINCAID COAL 2	ComEd	556.0	22-Jul-25	30-Nov-27
Total		1,871.2		

[129] At the time of the 2027/2028 BRA, the proposed deactivation date was June 1, 2027, for ROCKFORD CT 11, ROCKFORD CT 12, and ROCKFORD CT 21 and June 1, 2027, for FORKED RIVER C-1 and FORKED RIVER C-2.

RTO Market Results

Total Offers

Table 5 shows total RTO offer data for the 2027/2028 RPM Base Residual Auction. All MW values stated in the RTO section include all nested LDAs.[130] [131] As shown in Table 5, total internal RTO unforced capacity (UCAP), excluding generation winter capacity, increased 2,482.2 MW (1.7 percent) from 149,688.5 MW in the 2026/2027 RPM BRA to 152,170.7 MW.[132]

When comparing UCAP MW levels from one auction to another, two variables, capacity modifications and UCAP conversion changes, need to be considered. The net internal capacity change attributable to capacity modifications can be determined by holding the UCAP conversion factor level constant at the prior auction's level. The UCAP conversion effect is the measure of the net internal capacity change attributable to UCAP conversion factor changes and not capacity modifications. As shown in Table 7, the 2,482.2 MW increase in internal capacity was a result of net generation capacity modifications (cap mods) (1,525.5 MW), net DR capacity changes (-898.6 MW), the UCAP conversion effect due to lower UCAP conversion factors (-274.1 MW), and the DR UCAP conversion effect due to a higher load management UCAP conversion factor (2,129.4 MW).[133]

---

[130] Nested LDAs occur when a constrained LDA is a subset of a larger constrained LDA or the RTO. For example, MAAC and ATSI are nested in the RTO.

[131] Maps of the LDAs can be found in the *2019 Annual State of the Market Report for PJM*, Appendix A, PJM Overview, Figure A-3, Figure A-4, and Figure A-5.

[132] The reported internal capacity includes FRR capacity.

[133] Prior to the 2018/2019 Delivery Year, the UCAP value of DR was equal to the ICAP value multiplied by the Demand Resource (DR) Factor and the Forecast Pool Requirement (FPR). Effective for the 2018/2019 through the 2024/2025 Delivery Years, the UCAP value of DR is equal to the ICAP value multiplied by the FPR. Effective with the 2025/2026 and subsequent delivery years, the UCAP value of DR is equal to the ICAP value multiplied by the demand resource ELCC class rating. For the 2026/2027 BRA, this conversion factor was 0.6900 for DR. For the 2027/2028 BRA, this conversion factor was 0.9200 for DR. The DR Factor was designed to reflect the difference in losses that occur on the distribution system between the meter where demand is measured and the transmission system. The FPR multiplier is designed to recognize the fact that when demand is reduced by one MW, the system does not need to procure that MW or the associated reserve. See RAA Schedule 6, Section B. See also "PJM Manual 20A: PJM Resource Adequacy Analysis," § 2 Reserve Requirement Study (RRS) and Effective Load Carrying Capability (ELCC) Study, Rev. 2 (Dec. 17, 2025).

As shown in Table 9, total internal RTO unforced winter seasonal capacity for November through April decreased 135.9 MW from 1,161.6 MW in the 2026/2027 BRA to 1,025.7 MW in the 2027/2028 BRA. The 135.9 MW decrease in winter seasonal capacity was a result of net generation winter capacity modifications.

The net generation capacity modifications reflect new and reactivated generation, deactivations, and cap mods to existing generation. Total internal RTO unforced capacity includes all Generation Capacity Resources and Demand Resources that qualified as PJM Capacity Resources for the 2027/2028 RPM Base Residual Auction, excluding external units, and also includes owners' modifications to installed capacity (ICAP) ratings which are permitted under the RAA and associated manuals.[134] The ICAP of a unit may only be reduced through a cap mod if the capacity owner does not intend to restore the reduced capability by the end of the planning period following the planning period in question.[135] Otherwise the owner must take an outage, as appropriate, if the owner cannot provide energy consistent with the ICAP of the unit. Capacity modifications and DR plan changes were the result of owner reevaluation of the capabilities of their generation and DR.

After accounting for generation winter capacity (610.0 MW), for FRR committed resources (11,637.9 MW) and for imports (1,144.8 MW), total RPM capacity was 142,187.6 MW compared to 139,613.3 MW in the 2026/2027 RPM Base Residual Auction.[136] Generation winter capacity decreased by 66.0 MW, FRR volumes decreased by 295.0 MW, and imports decreased by 136.9 MW from the 2026/2027 RPM Base Residual Auction.[137]

Of the 1,144.8 MW of imports, 0.0 MW were committed to an FRR capacity plan and 1,144.8 MW were offered in the auction, of which 1,005.9 MW cleared. Of the cleared imports, 695.6 MW (69.2 percent) were from MISO.

---

134 See RAA Schedule 9.

135 "PJM Manual 21B: PJM Rules and Procedures for Determination of Generating Capability," § 11.1 Net Capability - General, Rev. 5 (Jan. 22, 2026). The manual states "the end of the next Delivery Year."

136 The FRR alternative allows a load serving entity (LSE), subject to certain conditions, to avoid direct participation in the RPM Auctions. The LSE is required to submit an FRR capacity plan to satisfy the unforced capacity obligation for all load in its service area.

137 Unless otherwise specified, an annual equivalent MW quantity is used to report winter capacity, which is calculated as the winter capacity MW times the ratio of the number of days in the winter period (November through April of the delivery year) to the number of days in the delivery year.

RPM capacity was reduced by exports of 1,980.4 MW, a decrease of 200.8 MW from the 2026/2027 RPM Base Residual Auction. Of total exports, 831.0 MW (42.0 percent) were to MISO, 509.8 MW (25.7 percent) were to NYISO, 166.1 MW (8.4 percent) were to Louisville Gas and Electric Company (LG&E)/Kentucky Utilities Company (KU), 384.3 MW (19.4 percent) were to Tennessee Valley Authority, and 89.2 MW (4.5 percent) were to Duke Energy Carolinas.

RPM capacity was also reduced by 90.2 MW of FRR optional volumes not offered and by 1,866.1 MW which were excused from the RPM must offer requirement.[138] FRR optional volumes increased by 16.3 MW and excused Existing Generation Capacity Resources increased by 1,174.8 MW from the 2026/2027 RPM Base Residual Auction. The excused Existing Generation Capacity Resources were the result of plans for retirement, physical operational restrictions, and export transactions.[139]

In addition, RPM capacity was reduced by 910.5 MW of Planned Generation Capacity Resources which were not subject to the must offer requirement, and by 1,005.0 MW of unoffered DR which were not subject to the RPM must offer requirement.[140] Unoffered Planned Generation Capacity Resources increased by 563.6 MW, and unoffered DR decreased by 543.5 MW from the 2026/2027 RPM Base Residual Auction.

Subtracting excused and unoffered capacity resulted in 136,535.4 MW that were available to be offered in the RPM Auction, an increase of 1,563.9 MW from the 2026/2027 RPM Base Residual Auction. After accounting for these factors, 953.7 MW were not offered and unexcused in the RPM Auction.

Offered MW increased 963.3 MW from 134,618.5 MW to 135,581.7 MW, while the overall RTO Reliability Requirement adjusted for FRR obligations, from which the demand curve is developed, increased 6,581.7 MW from 134,519.5 MW in the 2026/2027 RPM Base

---

138 FRR entities are allowed to offer in the RPM Auction excess volumes above their FRR quantities, subject to a sales cap amount. The FRR optional MW are a combination of excess volumes included in the sales cap amount which were not offered in the auction and volumes above the sales cap amount which were not permitted to offer in the auction.

139 See OATT Attachment M-Appendix § II.C.4 for the reasons to qualify for an exception to the RPM must offer requirement.

140 Unoffered DR and EE MW include PJM approved DR plans and EE plans that were not offered in the auction.

Residual Auction to 141,101.2 MW.[141] The RTO Reliability Requirement adjusted for FRR obligations is calculated as the RTO forecast peak load times the Forecast Pool Requirement (FPR), less FRR UCAP obligations. The FPR is calculated as (1+Installed Reserve Margin) times Pool wide accredited UCAP factor, where the Installed Reserve Margin (IRM) is the level of installed capacity needed to maintain an acceptable level of reliability.[142] The 6,581.7 MW increase in the RTO Reliability Requirement adjusted for FRR obligations from the 2026/2027 RPM Base Residual Auction was a result of a 6,295.4 MW increase in the RTO Reliability Requirement not adjusted for FRR and a 286.3 MW decrease in the FRR obligation, shifting the RTO market demand curve to the right. The forecast peak load expressed in terms of installed capacity increased 5,249.9 MW from the 2026/2027 RPM Base Residual Auction to 164,579.0 MW. The 6,295.4 MW increase in the RTO Reliability Requirement was a result of a 4,814.1 MW increase in the forecast peak load in UCAP terms holding the FPR constant at the 2026/2027 level and a 1,481.3 MW increase attributable to the change in the FPR. The increase in the FPR from the 2026/2027 RPM Base Residual Auction was a result of an increase in the pool wide accredited UCAP factor and an increase in the IRM.

Table 10 shows the installed and offered generation capacity for the top five owners. The total installed capacity (193,401.2 ICAP MW) includes all Generation Capacity Resources that qualified as PJM Capacity Resources for the 2027/2028 RPM Base Residual Auction (191,530.6 ICAP MW), annual equivalent MW quantity for generation winter capacity (510.0 ICAP MW), and external resources offered or committed to an FRR plan (1,360.6 ICAP MW).

Clearing Prices

Table 12 shows the clearing prices for 2026/2027 BRA and 2027/2028 BRA. The clearing price for the RTO increased by $4.27 or 1.3 percent from $329.17 in the 2026/2027 BRA to $333.44 in the 2027/2028 BRA. The higher clearing prices in 2027/2028 BRA were primarily the result of existing and forecast data center load. (See Part A of this report.)

---

[141] Unless otherwise specified, an annual equivalent MW quantity is used to report seasonal capacity, which is calculated as the MW times the ratio of the number of days in the seasonal period to the number of days in the delivery year. The offered capacity in this report differs from the PJM reported numbers due to seasonal versus annual equivalent MW reporting for seasonal offers, and the classification of and UCAP conversion for the underlying resources in aggregate resources.

[142] RAA Schedule 4.1.

Composition of the Steeply Sloped Portion of the Supply Curve

Table 20 shows the composition of the offers on the steeply sloped portion of the total RTO supply curve from $35.00 per MW-day. Overall, total offers greater than $35 per MW-day increased 21.8 percent, from 18,826.7 MW in the 2026/2027 BRA to 22,934.5 MW in the 2027/2028 BRA. Offers for DR were 25.6 percent of the offers greater than $35.00 per MW-day compared to 18.6 percent in the 2026/2027 RPM Base Residual Auction. Offers for coal fired units made up 22.3 percent of the offers greater than $35.00 per MW-day compared to 29.3 percent in the 2026/2027 RPM Base Residual Auction. Offers for combined cycle units made up 20.7 percent of the offers greater than $35.00 per MW-day compared to 22.7 percent in the 2026/2027 RPM Base Residual Auction.

Demand Side Resources

Table 25 shows offered and cleared capacity from DR in the 2027/2028 RPM Base Residual Auction compared to the 2026/2027 RPM Base Residual Auction. Offers for DR increased from 5,469.3 MW in the 2026/2027 BRA to 7,165.0 MW in the 2027/2028 BRA, an increase of 1,695.7 MW or 31.0 percent. Of the 7,165.0 MW offered for DR, all 7,165.0 MW cleared as shown in Table 19.

Capacity Imports

Table 26 shows the MW quantity of imports offered and cleared in the 2007/2008 through 2027/2028 RPM Base Residual Auctions. The highest level of offered (7,493.7 MW) and cleared (7,482.7 MW) imports occurred in the 2016/2017 RPM BRA, which was prior to the implementation of the CIL rules and prior to the implementation of the pseudo tie rules. Of the 1,144.8 MW of imports offered in the 2027/2028 RPM BRA, 1,005.9 MW (87.9 percent) cleared.

CETO/CETL Values

Table 21 shows the CETL and CETO values used in the 2027/2028 study compared to the 2026/2027 values. The CETL value for the PPL LDA increased significantly. PJM stated that the significant increase in the PPL CETL "is attributed to the Wescoville 500/230 kV transformer coming on line."[143] The CETL value for ComEd LDA decreased significantly. PJM stated that the significant decrease in the ComEd CETL "is ascribed to resource deactivations and impacts from external systems."

Prior to the 2021/2022 BRA, PJM included capacity imports and exports secured with both firm and nonfirm transmission in the CETL studies. Starting with the 2021/2022 BRA, PJM

[143] See the PJM "2027/2028 RPM Base Residual Auction Planning Period Parameters," (February 10, 2026) <https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2027-2028/2027-2028-planning-period-parameters-for-base-residual-auction-pdf.pdf>.

included only capacity imports and exports secured with firm transmission in the CETL studies. For the 2021/2022 BRA, all imports and exports secured with firm transmission that were approved and confirmed by PJM regardless of their approval status from the neighboring regions were included in CETL studies despite the fact that some were not and could not be capacity imports. PJM made rule changes such that starting with the 2022/2023 BRA only those imports and exports secured with firm transmission that were approved and confirmed by all relevant entities are included in the CETL cases.[144] The MMU recommends that CETL be based on the ability to import capacity only where PJM capacity exists and where that capacity has a must offer requirement in the PJM Capacity Market. Any other assumption overstates the amount of capacity supply and suppresses market prices for PJM capacity resources. The external capacity that does not have a must offer requirement in the PJM Capacity Market is not obligated to serve PJM load under all conditions and therefore should not be assumed to be a source of capacity. This capacity should not be included in PJM's power flow calculations used to derive CETL values between PJM's LDAs. PJM has modified its CETL calculations to exclude such capacity.

The Price Impacts of Constraints in the RPM Market

As is the case in locational energy markets, transmission constraints in the PJM capacity markets affect clearing prices both by increasing prices in constrained areas and decreasing prices in unconstrained areas. Conversely, removing constraints reduces prices in constrained areas and increases prices in unconstrained areas. The impact of transmission constraints on price separation and on total market revenues depends on the shapes of the supply and demand curves in LDAs.

There were no locationally binding constraints in the 2027/2028 BRA. Locationally binding constraints result in demand clearing in a locationally constrained LDA which does not clear in the RTO market or in contiguous or parent LDAs, and which clears at a higher price than in contiguous or parent LDAs. The result is to shift the demand curve in the RTO market to the left along the upwardly sloping supply curve and to reduce the price in the RTO market. The price impact is the result both of the size of the shift of the demand curve and the slope of the supply curve. The larger the shift in the demand curve and the steeper the slope of the supply curve, the greater the price impact.[145]

Nested LDAs occur when a constrained LDA is a subset of a larger constrained LDA or the RTO. The supply and demand curves for nested LDAs can be presented in two ways to illustrate the market clearing dynamic. The supply curves in the figures in this report,

---

144 See "PJM Manual 14B: PJM Region Transmission Planning Process," § C.3.1.3 General Procedures and Assumptions, Rev. 59 (April 22, 2026).

145 For more details on the clearing algorithm, see Attachment A.

unless otherwise noted, show the total internal supply of the LDA, including all nested LDAs and not including CETL MW. The demand curve is reduced by the CETL and by the MW that cleared incrementally in the constrained, nested LDAs.

Clearing Results

The net load price that load serving entities (LSEs) will pay is equal to the final zonal capacity price less the final Capacity Transfer Rights (CTR) credit rate.[146] [147] As shown in Table 11, the preliminary net load price is $333.69 per MW-day in the RTO. The adjusted preliminary zonal capacity price of RTO was higher than the preliminary zonal capacity price due to the adjustment to cover the funding for PRD credits in BGE.

As shown in Table 13 and Table 14, the 134,478.1 MW of cleared generation and DR for the entire RTO, resulted in a reserve margin of 14.4 percent and a net deficit of 6,516.6 MW over the reliability requirement adjusted for FRR and PRD of 140,994.7 MW (Installed Reserve Margin (IRM) of 20.0 percent).[148] [149] [150] Net excess decreased 6,307.9 MW from the net deficit of 208.7 MW in the 2026/2027 RPM Base Residual Auction to a net deficit of 6,516.6 MW in the 2027/2028 RPM Base Residual Auction. As shown in Figure 2, the

---

146 Effective with the 2012/2013 Delivery Year, Final Zonal Capacity Prices and the final CTR credit rate are determined after the final Incremental Auction.

147 In the Base Residual Auction, PJM models PRD on the supply side. The cleared PRD is credited with the adjusted zonal clearing price of the LDA in which they cleared. The PRD credits are charged to the load of those LDAs. The net load price reflects these adjustments to cover the funding of PRD credits.

148 Prior to the 2012/2013 Delivery Year, net excess under RPM was calculated as cleared capacity less the reliability requirement plus ILR. For the 2012/2013 through the 2017/2018 Delivery Years, net excess under RPM is calculated as cleared capacity less the reliability requirement plus the Short-Term Resource Procurement Target. For the 2018/2019 Delivery Year, the net excess under RPM is calculated as cleared capacity less the reliability requirement. For the 2019/2020 and subsequent delivery years, the net excess under RPM is calculated as cleared generation and DR capacity less the reliability requirement. MW that clear but require uplift payments are not included in PJM's definition of cleared capacity and therefore excess capacity. Those MW should be included in the definition of cleared capacity and therefore excess capacity.

149 The IRM increased from 19.1 percent in the 2026/2027 RPM Base Residual Auction to 20.0 percent in the 2027/2028 RPM Base Residual Auction.

150 These reserve margin calculations do not consider Fixed Resource Requirement (FRR) load.

maximum price on the VRR demand curve resulted in a clearing price for Capacity Performance Resources of $333.44 per MW-day.

The actual market results in the 2027/2028 BRA did not include uplift MW and payments resulting from inflexibly offered partially cleared resources. PJM does not include the uplift MW in the reported cleared capacity and therefore does not include uplift MW in the calculation of reserves and excess reserves. Uplift MW are cleared MW with the same capacity status as all other cleared capacity MW and therefore should be included in reported cleared capacity and in the calculation of reserves and excess reserves.

Uplift MW and payments can also occur for resources electing the New Entry Price Adjustment (NEPA) or Multi-Year Pricing Option.[151] [152] If an offer clears in an auction under either option and if a qualifying resource does not clear in the two subsequent BRAs, the process specified in the Tariff is triggered, and the resource is awarded an uplift payment.[153] The market results in the 2027/2028 BRA did not include make whole MW or payments related to NEPA or Multi-Year Pricing Option.

The market results in the 2027/2028 BRA did not include seasonal uplift MW and payments. Under the seasonal capacity rules, the optimization considers the average cost of clearing seasonal offers, including an offer in each season. This can result in clearing seasonal sell offers for the higher cost season at offer prices that are not competitive and making seasonal uplift payments based on those high offer prices.

Table 15 shows offered and cleared MW by LDA, resource type, and season in the 2027/2028 RPM Base Residual Auction. Of the 128,416.7 MW of generation offers, 127,989.1 MW were for the annual season. Of the 7,165.0 MW of DR offers, 7,030.0 MW were for the annual season.

Table 16 shows the weighted average sell offer prices by LDA, resource type, and season. The weighted average sell offer prices for generation in RTO for annual were greater than the weighted average sell offer prices for winter. The weighted average sell offer prices for DR in RTO for annual were greater than the weighted average sell offer prices for summer. The weighted average sell offer prices for annual DR were greater than the weighted average sell offer prices for annual generation.

---

151 OATT Attachment DD § 5.14(c)(2).

152 OATT Attachment DD § 6.8(a).

153 OATT Attachment DD § 5.14(c)(2)(ii).

In the absence of data on the marginal cost of providing DR, it is difficult to determine whether such resources are offered at levels equal to, greater than or less than marginal cost. If such resources are offered at prices in excess of marginal cost, the result would be prices greater than competitive levels. If such resources are offered at prices less than marginal cost, the result would be prices less than competitive levels. Both potential outcomes are of significant concern. The RPM rules exempt DR from offer cap market power mitigation.

Table 17 shows the offered generation capacity MW by season and price range relative to the applicable market seller offer caps (MSOCs) in the 2027/2028 RPM Base Residual Auction. Of the 128,416.7 MW of generation offers, 26,655.7 MW (20.8 percent) were offered below the applicable MSOC, 101,761.0 MW (79.2 percent) were offered at the applicable MSOC, and 0.0 MW (0.0 percent) of the offers used in the auction were greater than the applicable MSOC.

Table 18 shows the weighted average sell offer prices and market seller offer caps for existing generation capacity resources in the entire RTO. The weighted average sell offer for existing generation capacity resources ($13.63 per MW-day) was about two thirds the weighted average market seller offer cap ($21.36 per MW-day). The weighted average sell offer for existing generation capacity resources was well below the final clearing price of $333.44 per MW-day that resulted from the maximum price on the VRR curve.

Table 19 shows cleared MW by zone and fuel source. Of the 128,416.7 MW offered for generation resources, 127,313.1 MW cleared (99.1 percent). Of the 134,478.1 cleared MW in the entire RTO, 19,914.6 MW (14.8 percent) cleared in Dominion, followed by 19,567.1 MW (14.6 percent) in ComEd and 17,032.1 MW (12.7 percent) in AEP. Of the 127,313.1 cleared MW for generation resources in the entire RTO, 60,982.5 MW (47.9 percent) were gas resources, followed by 28,490.8 MW (22.4 percent) from nuclear resources and 23,996.6 MW (18.8 percent) from coal resources. Cleared MW from DR increased 1,695.7 MW from the 2026/2027 RPM Base Residual Auction while cleared MW from coal resources decreased 738.4 MW from the 2026/2027 RPM Base Residual Auction.

The 1,103.6 MW uncleared MW in the entire RTO were the result of offer prices which exceeded the clearing prices or winter offers which were not matched with summer offers. The maximum price was known to participants prior to the BRA. Of the 1,103.6 uncleared MW in the entire RTO, all 1,103.6 MW were generation offers.[154]

[154] Reported uncleared MW values are based on rounded annual equivalent MW values for seasonal offers.

CTRs

Capacity Transfer Rights (CTRs) are used to return capacity market congestion revenues to load. Load pays congestion. Capacity market congestion revenues are the difference between the total dollars paid by load for capacity and the total dollars received by capacity market sellers. For LDAs in which the RPM auctions for a delivery year resulted in a positive locational price adder, an LSE with load in the LDA is entitled to a payment equal to the locational price adder multiplied by the MW of the LSEs' CTRs.[155] [156] The MW of CTRs available for allocation to LSEs in an LDA are equal to the Unforced Capacity imported into the LDA, less any MW of CETL paid for directly by market participants in the form of Qualifying Transmission Upgrades (QTUs) cleared in an RPM Auction, and Incremental Capacity Transfer Rights (ICTRs). There are two types of ICTRs, those allocated to a New Service Customer obligated to fund a transmission facility or upgrade and those associated with Incremental Rights-Eligible Required Transmission Enhancements.[157]

The 2027/2028 RPM Base Residual Auction cleared at $333.44 per MW-day with no price separation and therefore the value of CTRs and ICTRs was $0.

---

[155] The locational price adder for a child LDA is the difference between the resource clearing price in the child LDA and the resource clearing price in the corresponding parent LDA.

[156] But PJM does not use the actual MW cleared in the BRA and three incremental auctions, the actual internal MW and the actual imported MW, when defining what customers pay and when defining the value of CTRs.

[157] Incremental Rights-Eligible Required Transmission Enhancements are regional facilities and necessary lower voltage facilities or lower voltage facilities where cost responsibility is assigned to non-contiguous transmission zones that are not directly electrically connected, or cost responsibility is assigned to merchant transmission providers that are responsible customers. See "PJM Manual 18: PJM Capacity Market," § 6.1 Definition and Purpose of Capacity Transfer Rights, Rev. 62 (Dec. 17, 2025).

Tables and Figures for RTO Market

Table 5 RTO offer statistics: 2027/2028 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	191,530.6	143,657.9		
DR capacity	9,257.4	8,512.8		
Generation winter capacity	510.0	510.0		
Total internal RTO capacity	201,298.0	152,680.7		
FRR	(14,372.2)	(11,637.9)		
Imports	1,360.6	1,144.8		
RPM capacity	188,286.4	142,187.6		
Exports	(2,505.4)	(1,980.4)		
FRR optional	(161.3)	(90.2)		
Excused Existing Generation Capacity Resources	(3,037.6)	(1,866.1)		
Unoffered Planned Generation Capacity Resources	(1,068.9)	(710.5)		
Unoffered DR	(1,092.5)	(1,005.0)		
Available	180,420.8	136,535.4	100.0%	100.0%
Generation offered	171,088.2	128,416.7	94.8%	94.1%
DR offered	7,792.4	7,165.0	4.3%	5.2%
Total offered	178,880.6	135,581.7	99.1%	99.3%
Unoffered Existing Generation Capacity Resources	1,540.2	953.7	0.9%	0.7%

Table 6 Capacity modifications (ICAP): 2027/2028 RPM Base Residual Auction[158]

	ICAP (MW) RTO
Generation increases	5,221.5
Generation decreases	(666.5)
Capacity modifications net increase/(decrease)	4,555.0
DR increases	506.0
DR decreases	(1,806.7)
DR net increase/(decrease)	(1,300.7)
Net internal capacity increase/(decrease)	3,254.3

Table 7 Capacity modifications (UCAP): 2027/2028 RPM Base Residual Auction

	UCAP (MW) RTO
Generation increases	1,955.8
Generation decreases	(430.3)
Capacity modifications net increase/(decrease)	1,525.5
DR increases	348.1
DR decreases	(1,246.7)
DR net increase/(decrease)	(898.6)
Net capacity/DR modifications increase/(decrease)	626.9
Generation UCAP conversion effect	(274.1)
DR UCAP conversion effect	2,129.4
Net internal capacity increase/(decrease)	2,482.2

[158] Only cap mods that had a start date on or before June 1, 2027, and DR plans for the 2027/2028 RPM Base Residual Auction are included.

Table 8 Winter capacity modifications (ICAP): 2027/2028 RPM Base Residual Auction

	ICAP (MW) RTO
Generation increases	298.2
Generation decreases	(434.1)
Capacity modifications net increase/(decrease)	(135.9)
DR increases	0.0
DR decreases	0.0
DR net increase/(decrease)	0.0
Net internal capacity increase/(decrease)	(135.9)

Table 9 Winter capacity modifications (UCAP): 2027/2028 RPM Base Residual Auction

	UCAP (MW) RTO
Generation increases	298.2
Generation decreases	(434.1)
Capacity modifications net increase/(decrease)	(135.9)
DR increases	0.0
DR decreases	0.0
DR net increase/(decrease)	0.0
Net capacity/DR modifications increase/(decrease)	(135.9)
Generation UCAP conversion effect	0.0
DR UCAP conversion effect	0.0
Net internal capacity increase/(decrease)	(135.9)

Table 10 Installed and offered generation capacity by parent company: 2027/2028 RPM Base Residual Auction

Parent Company	ICAP (MW)	Percent of Total ICAP	Offered ICAP (MW)	Percent of Total Offered ICAP
Dominion Resources, Inc.	20,943.5	10.8%	20,004.3	11.7%
Constellation Energy Generation, LLC	19,460.6	10.1%	19,460.6	11.5%
American Electric Power Company, Inc.	16,584.3	8.6%	2,390.9	1.5%
Vistra Energy Corp.	14,331.4	7.4%	13,219.4	7.4%
LS Power Equity Partners, L.P.	12,215.4	6.3%	11,645.8	7.0%

Table 11 Net load prices: 2027/2028 RPM Base Residual Auction

	$ per MW-day RTO
Resource clearing price	$333.44
Preliminary zonal capacity price	$333.44
Adjusted preliminary zonal capacity price	$333.69
Base zonal CTR credit rate	$0.00
Preliminary net load price	$333.69

Table 12 Clearing prices: 2026/2027 and 2027/2028 RPM Base Residual Auctions

			Change	
LDA	2026/2027 BRA	2027/2028 BRA	$ per MW-Day	Percent
RTO	$329.17	$333.44	$4.27	1.3%
MAAC	$329.17	$333.44	$4.27	1.3%
EMAAC	$329.17	$333.44	$4.27	1.3%
SWMAAC	$329.17	$333.44	$4.27	1.3%
PSEG	$329.17	$333.44	$4.27	1.3%
PSEG North	$329.17	$333.44	$4.27	1.3%
DPL South	$329.17	$333.44	$4.27	1.3%
Pepco	$329.17	$333.44	$4.27	1.3%
ATSI	$329.17	$333.44	$4.27	1.3%
ATSI Cleveland	$329.17	$333.44	$4.27	1.3%
ComEd	$329.17	$333.44	$4.27	1.3%
BGE	$329.17	$333.44	$4.27	1.3%
PPL	$329.17	$333.44	$4.27	1.3%
DAY	$329.17	$333.44	$4.27	1.3%
DEOK	$329.17	$333.44	$4.27	1.3%
Dominion	$329.17	$333.44	$4.27	1.3%
JCPL	$329.17	$333.44	$4.27	1.3%

Table 13 Reserve margin: 2027/2028 RPM Base Residual Auction

	Reserve Margin Calculation	
Forecast peak load ICAP (MW)	164,579.0	A
FRR peak load ICAP (MW)	12,201.9	B
PRD ICAP (MW)	115.0	C
Installed reserve margin (IRM)	20.0%	D
Pool-Wide Accredited UCAP Factor	77.17%	E
Forecast pool requirement (FPR)	0.9260	F=(1+D)*E
Cleared UCAP (generation and DR)	134,478.1	G
Cleared ICAP (generation and DR)	174,262.1	H=G/E
RPM peak load ICAP (MW)	152,262.1	J=A-B-C
Reserve margin ICAP (MW)	22,000.0	K=H-J
Reserve margin (%)	14.4%	L=K/J
Reserve cleared in excess of IRM ICAP (MW)	(8,452.4)	M=K-D*J
Reserve cleared in excess of IRM (%)	(5.6%)	N=M/J
RPM peak load UCAP (MW)	117,500.7	P=J*E
RPM reliability requirement UCAP (MW)	140,994.7	Q=J*F
Reserve margin UCAP (MW)	16,977.4	R=G-P
Reserve cleared in excess of IRM UCAP (MW)	(6,516.6)	S=G-Q

Table 14 Net excess: 2027/2028 RPM Base Residual Auction

	RTO	
Cleared UCAP generation and DR	134,478.1	A
CETL	NA	B
Reliability requirement UCAP (MW)	152,400.2	C
FRR peak load ICAP (MW)	12,201.9	D
PRD ICAP (MW)	115.0	E
Forecast pool requirement (FPR)	0.9260	F
RPM Reliability requirement UCAP (MW)	140,994.7	G=C-D*F-E*F
Net excess/(deficit) UCAP (MW)	(6,516.6)	H=A+B-G

Table 15 Offered and cleared capacity by LDA, resource type, and season type: 2027/2028 RPM Base Residual Auction

		Offered UCAP (MW)			Cleared UCAP (MW)		
LDA	Resource Type	Annual	Summer	Winter	Annual	Summer	Winter
RTO	GEN	127,989.1	0.0	427.6	127,179.5	0.0	133.6
RTO	DR	7,030.0	135.0	0.0	7,030.0	135.0	0.0

Table 16 Weighted average sell offer prices by LDA, resource type, and season type: 2027/2028 RPM Base Residual Auction

		Weighted-Average ($ per MW-day UCAP)		
LDA	Resource Type	Annual	Summer	Winter
RTO	GEN	$14.04		$3.05
RTO	DR	$116.54	$5.22	

Table 17 Offered generation capacity by season type and price range relative to market seller offer cap (MSOC): 2027/2028 RPM Base Residual Auction

	Offered UCAP (MW)		
Season Type	< MSOC	= MSOC	> MSOC
Annual	26,649.8	101,339.3	0.0
Summer	0.0	0.0	0.0
Winter	5.9	421.7	0.0

Table 18 Weighted average sell offer prices and market seller offer caps: 2025/2026, 2026/2027, and 2027/2028 RPM Base Residual Auctions[159]

			Weighted-Average ($ per MW-day UCAP)		
Base Residual Auction	LDA	Resource Type	Sell Offers	Market Seller Offer Caps	Ratio of Sell Offers to Market Seller Offer Caps
2025/2026	RTO	GEN	$8.07	$15.91	0.51
2026/2027	RTO	GEN	$11.19	$18.23	0.61
2027/2028	RTO	GEN	$13.63	$21.36	0.64

[159] The underlying data used for Table 16 includes all sell offers. The underlying data used for Table 18 includes only those sell offers subject to market seller offer caps.

Table 19 Cleared MW by zone and resource type/fuel source: 2027/2028 RPM Base Residual Auction[160]

	Cleared UCAP (MW)											
Zone	DR	Battery Storage	Coal	Gas	Hybrid	Hydro	Nuclear	Oil	Solar	Solid Waste	Wind	Total
AECO	45.6	0.0	0.0	604.8	0.0	0.0	0.0	0.0	3.4	0.0	0.0	653.8
AEP	1,105.6	116.0	5,228.9	9,179.5	0.0	57.1	31.2	0.0	489.2	0.0	824.6	17,032.1
AP	553.1	0.0	4,252.6	3,297.0	0.0	102.2	0.0	0.0	83.6	0.0	254.4	8,542.9
ATSI	672.3	0.0	734.8	3,979.6	0.0	0.0	2,036.1	129.4	51.4	0.0	0.0	7,603.6
BGE	169.2	0.5	1,135.8	194.5	0.0	0.0	1,544.3	667.9	2.6	46.8	0.0	3,761.6
ComEd	1,466.5	0.0	695.7	6,024.1	0.0	0.0	9,715.2	206.2	5.9	0.0	1,453.5	19,567.1
DAY	172.1	0.0	0.0	646.6	0.0	0.0	0.0	30.5	79.7	0.0	0.0	928.9
DEOK	198.6	0.0	1,312.8	775.3	0.0	65.5	0.0	40.8	23.6	0.0	0.0	2,416.6
DLCO	122.1	0.0	0.0	178.7	0.0	0.0	1,521.6	15.5	4.6	0.0	0.0	1,842.5
Dominion	767.9	81.4	2,245.2	10,038.9	7.4	2,412.2	3,442.3	210.3	513.4	103.2	92.5	19,914.6
DPL	153.0	0.0	0.0	3,116.8	0.0	0.0	0.0	537.0	52.8	0.0	0.0	3,859.6
EKPC	207.0	0.0	1,503.3	915.2	0.0	84.9	0.0	0.0	39.3	0.0	0.0	2,749.7
External	0.0	0.0	695.6	0.0	0.0	310.3	0.0	0.0	0.0	0.0	0.0	1,005.9
JCPL	89.3	0.0	0.0	1,989.7	0.0	283.7	0.0	113.9	20.0	0.0	0.0	2,496.6
Met-Ed	132.8	0.0	5.8	2,026.4	0.0	9.2	0.0	318.4	11.5	45.5	0.0	2,549.6
OVEC	0.0	0.0	1,152.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,152.4
PECO	266.4	0.0	0.0	2,607.8	0.0	1,239.9	4,597.0	687.9	0.1	91.6	0.0	9,490.7
PENELEC	171.5	0.0	3,531.9	2,100.2	0.0	370.6	0.0	71.4	33.8	39.8	278.5	6,597.7
Pepco	213.4	0.0	0.0	2,334.9	0.0	0.0	0.0	204.9	2.3	39.3	0.0	2,794.8
PPL	421.6	0.0	1,501.8	7,203.5	0.0	535.9	2,392.6	32.6	17.9	8.4	32.3	12,146.5
PSEG	234.1	0.0	0.0	3,769.0	0.0	0.5	3,210.5	0.0	10.3	143.4	0.0	7,367.8
RECO	3.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.2
Total	7,165.0	197.9	23,996.6	60,982.5	7.4	5,472.0	28,490.8	3,266.7	1,445.4	518.0	2,935.8	134,478.1

[160] Resources that operate at or above 500 kV may be physically located in a zonal LDA but are modeled in the parent LDA. For example, 3,210.5 MW of the 7,367.8 cleared MW in the PSEG Zone were modeled and cleared in the EMAAC LDA.

Table 20 Offers greater than $35.00 per MW-day in total RTO supply curve: 2027/2028 RPM Base Residual Auction[161] [162]

Technology/Resource Type	Offered UCAP (MW)	Percent of Offers
Demand Resource	5,875.6	25.6%
Coal fired	5,112.8	22.3%
Combined cycle	4,744.3	20.7%
Combustion turbine	3,783.5	16.5%
Oil or gas steam	3,235.6	14.1%
Other generation	182.7	0.8%
Total	22,934.5	100.0%

Table 21 PJM LDA CETL and CETO values: 2026/2027 and 2027/2028 RPM Base Residual Auctions

	2026/2027			2027/2028			Change			
							CETO		CETL	
LDA	CETO	CETL	CETL to CETO Ratio	CETO	CETL	CETL to CETO Ratio	MW	Percent	MW	Percent
MAAC	590.0	2,715.0	460.2%	1,738.0	2,598.0	149.5%	1,148.0	194.6%	(117.0)	(4.3%)
EMAAC	6,072.0	8,083.0	133.1%	6,366.0	8,025.0	126.1%	294.0	4.8%	(58.0)	(0.7%)
SWMAAC	6,877.0	6,999.0	101.8%	6,760.0	6,698.0	99.1%	(117.0)	(1.7%)	(301.0)	(4.3%)
PSEG	6,713.0	8,889.0	132.4%	6,878.0	9,307.0	135.3%	165.0	2.5%	418.0	4.7%
PSEG North	3,017.0	4,425.0	146.7%	3,097.0	4,623.0	149.3%	80.0	2.7%	198.0	4.5%
DPL South	1,615.0	1,948.0	120.6%	1,642.0	1,974.0	120.2%	27.0	1.7%	26.0	1.3%
Pepco	4,334.0	5,870.0	135.4%	4,242.0	6,776.0	159.7%	(92.0)	(2.1%)	906.0	15.4%
ATSI	3,800.0	10,406.0	273.8%	3,874.0	9,919.0	256.0%	74.0	1.9%	(487.0)	(4.7%)
ATSI Cleveland	3,720.0	5,199.0	139.8%	3,802.0	4,938.0	129.9%	82.0	2.2%	(261.0)	(5.0%)
ComEd	(1,236.0)	6,110.0	(494.3%)	(1,168.0)	3,965.0	(339.5%)	68.0	(5.5%)	(2,145.0)	(35.1%)
BGE	4,775.0	6,000.0	125.7%	4,750.0	5,975.0	125.8%	(25.0)	(0.5%)	(25.0)	(0.4%)
PPL	1,144.0	3,205.0	280.2%	2,161.0	6,181.0	286.0%	1,017.0	88.9%	2,976.0	92.9%
DAY	2,626.0	4,157.0	158.3%	2,796.0	4,665.0	166.8%	170.0	6.5%	508.0	12.2%
DEOK	2,793.0	5,280.0	189.0%	2,805.0	4,938.0	176.0%	12.0	0.4%	(342.0)	(6.5%)
Dominion	5,511.0	7,374.0	133.8%	6,802.0	6,598.0	97.0%	1,291.0	23.4%	(776.0)	(10.5%)
JCPL	3,790.0	4,263.0	112.5%	3,692.0	4,331.0	117.3%	NA	NA	NA	NA

[161] Effective for the 2017/2018 and subsequent delivery years, the ACR technology classes of waste coal small and large were eliminated and combined with subcritical and supercritical coal to form the Coal Fired ACR technology class. Waste coal resources were included in the other category in versions of this table prior to the 2017/2018 BRA. For the 2027/2028 BRA, waste coal resources are included in the coal fired category.

[162] Data aggregated based on PJM confidentiality rules.

Figure 1 Shape of the VRR curve relative to the reliability requirement: 2027/2028 RPM Base Residual Auction

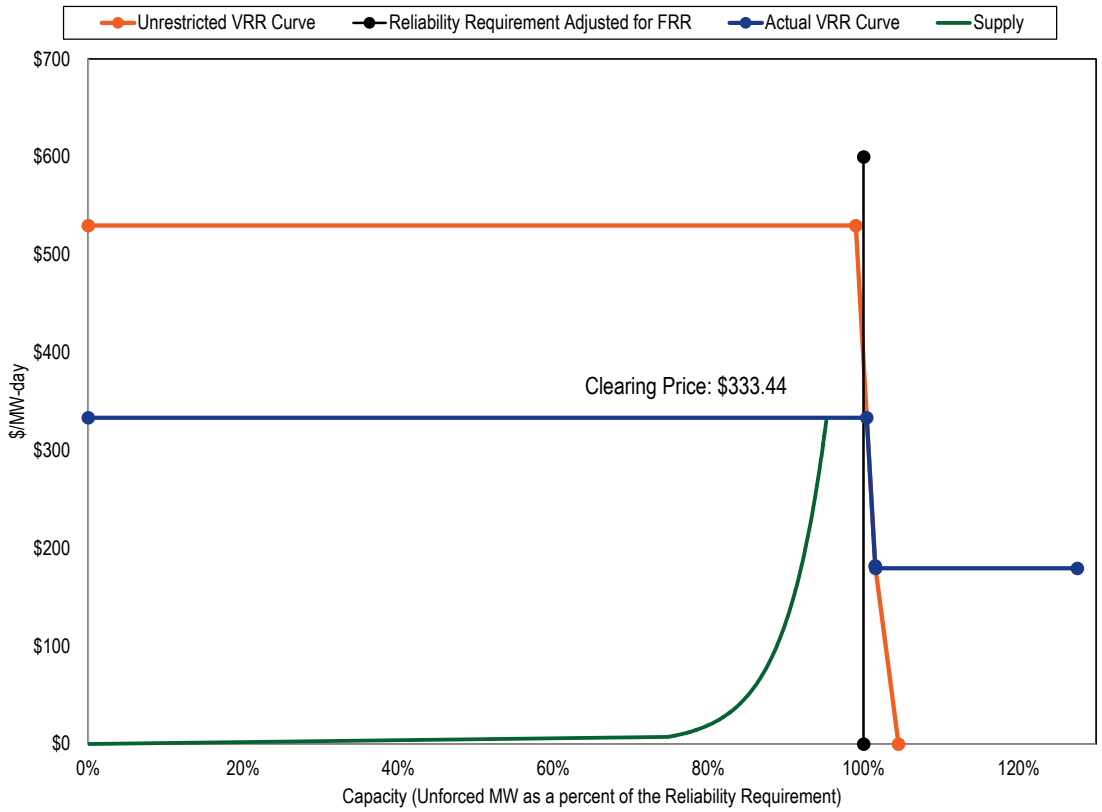


Table 22 Price coordinates for 2027/2028 RPM BRA actual VRR curve

	Point A		Point B		Point C		Point D	
LDA	$/MW-day	MW	$/MW-day	MW	$/MW-day	MW	$/MW-day	MW
RTO	$333.44	141,681.1	$181.89	143,217.7	$179.55	143,272.2	$179.55	147,450.8
MAAC	$333.44	54,901.8	$226.13	55,387.3	$179.55	55,724.5	$179.55	57,024.4
EMAAC	$333.44	31,276.3	$269.13	31,415.0	$179.55	31,724.1	$179.55	32,343.5
SWMAAC	$333.44	13,538.4	$179.55	13,682.7	$179.55	14,102.1		
PSEG	$333.44	11,187.1	$304.07	11,207.1	$179.55	11,342.8	$179.55	11,538.4
PS-NORTH	$333.44	5,580.9	$304.07	5,590.9	$179.55	5,658.6	$179.55	5,756.2
DPL-SOUTH	$333.44	2,626.3	$196.96	2,655.3	$179.55	2,662.2	$179.55	2,733.8
PEPCO	$333.44	6,559.7	$219.23	6,620.8	$179.55	6,656.2	$179.55	6,816.5
ATSI	$333.44	12,260.7	$179.55	12,387.2	$179.55	12,760.3		
ATSI-CLEVELAND	$333.44	5,478.2	$179.55	5,534.7	$179.55	5,701.4		
COMED	$333.44	21,557.6	$284.31	21,626.6	$179.55	21,862.1	$179.55	22,265.8
BGE	$333.44	7,091.3	$179.55	7,157.0	$179.55	7,399.5		
PPL	$333.44	10,775.8	$236.55	10,858.0	$179.55	10,935.3	$179.55	11,178.9
DAY	$333.44	3,736.5	$179.55	3,772.6	$179.55	3,892.3		
DEOK	$333.44	5,575.8	$179.55	5,632.3	$179.55	5,804.5		
DOM	$333.44	27,584.1	$179.55	27,842.7	$179.55	28,745.1		
JCPL	$333.44	6,292.8	$299.65	6,305.9	$179.55	6,380.6	$179.55	6,492.3

Table 23 Price coordinates for 2027/2028 RPM BRA unrestricted VRR curve

	Point A		Point B		Point C	
LDA	$/MW-day	MW	$/MW-day	MW	$/MW-day	MW
RTO	$529.80	139,690.2	$181.89	143,217.7	$0.00	147,450.8
MAAC	$527.63	54,737.1	$226.13	56,101.3	$0.00	57,738.4
EMAAC	$627.97	30,641.2	$269.13	31,415.0	$0.00	32,343.5
SWMAAC	$523.74	13,473.8	$164.09	13,811.1	$0.00	14,216.0
PSEG	$709.50	10,931.1	$304.07	11,207.1	$0.00	11,538.4
PS-NORTH	$709.50	5,453.2	$304.07	5,590.9	$0.00	5,756.2
DPL-SOUTH	$504.63	2,589.9	$196.96	2,655.3	$0.00	2,733.8
PEPCO	$523.74	6,457.8	$219.23	6,620.8	$0.00	6,816.5
ATSI	$542.83	12,088.7	$171.26	12,394.0	$0.00	12,760.3
ATSI-CLEVELAND	$542.83	5,401.3	$171.26	5,537.7	$0.00	5,701.4
COMED	$663.39	21,093.9	$284.31	21,626.6	$0.00	22,265.8
BGE	$523.74	7,010.1	$108.94	7,187.1	$0.00	7,399.5
PPL	$551.95	10,590.5	$236.55	10,858.0	$0.00	11,178.9
DAY	$542.83	3,687.5	$145.37	3,780.6	$0.00	3,892.3
DEOK	$542.83	5,499.0	$164.58	5,637.8	$0.00	5,804.5
DOM	$542.83	27,232.2	$133.61	27,919.9	$0.00	28,745.1
JCPL	$699.18	6,150.6	$299.65	6,305.9	$0.00	6,492.3

Table 24 Peak load forecast history[163] [164] [165]

	DY	BRA	First IA	Second IA	Third IA	Actual DY Peak Load	Percent Change BRA to 1st	Percent Change BRA to 2nd	Percent Change BRA to 3rd	Percent Change BRA to Actual
Forecast Peak Load	2026 / 2027	159,329.1	NA	NA	156,760.6		NA	NA	(1.6%)	
Installed Reverve Margin		19.1%	NA	NA	18.6%		NA	NA	(2.6%)	
Pool Wide Accredited UCAP Factor		76.99%	NA	NA	78.34%		NA	NA	1.8%	
Forecast Pool Requirement		0.9170	NA	NA	0.9291		NA	NA	1.3%	
Reliability Requirement		146,104.8	NA	NA	145,646.3		NA	NA	(0.3%)	
Forecast Peak Load	2025 / 2026	153,883.0	NA	NA	154,534.1	160,157.7	NA	NA	0.4%	4.1%
Installed Reverve Margin		17.8%	NA	NA	17.8%		NA	NA	0.0%	
Pool Wide Accredited UCAP Factor		79.69%	NA	NA	79.63%		NA	NA	(0.1%)	
Forecast Pool Requirement		0.9387	NA	NA	0.9380		NA	NA	(0.1%)	
Reliability Requirement		144,450.0	NA	NA	144,953.0		NA	NA	0.3%	
Forecast Peak Load	2024 / 2025	150,640.3	NA	NA	151,631.1	152,551.6	NA	NA	0.7%	1.3%
Installed Reverve Margin		14.7%	NA	NA	17.7%		NA	NA	20.4%	
Pool Wide EFORd		5.02%	NA	NA	5.10%		NA	NA	1.6%	
Forecast Pool Requirement		1.0894	NA	NA	1.117		NA	NA	2.5%	
Reliability Requirement		164,107.6	NA	NA	169,371.9		NA	NA	3.2%	
Forecast Peak Load	2023 / 2024	149,680.0	NA	NA	149,382.2	147,175.0	NA	NA	(0.2%)	(1.7%)
Installed Reverve Margin		14.8%	NA	NA	14.9%		NA	NA	0.7%	
Pool Wide EFORd		5.04%	NA	NA	4.87%		NA	NA	(3.4%)	
Forecast Pool Requirement		1.0901	NA	NA	1.093		NA	NA	0.3%	
Reliability Requirement		163,166.2	NA	NA	163,274.7		NA	NA	0.1%	
Forecast Peak Load	2022 / 2023	150,229.0	NA	NA	149,263.6	147,771.2	NA	NA	(0.6%)	(1.6%)
Installed Reverve Margin		14.5%	NA	NA	14.9%		NA	NA	2.8%	
Pool Wide EFORd		5.08%	NA	NA	5.08%		NA	NA	0.0%	
Forecast Pool Requirement		1.0868	NA	NA	1.0906		NA	NA	0.3%	
Reliability Requirement		163,268.9	NA	NA	162,786.9		NA	NA	(0.3%)	

[163] Typically, the time between the BRA and the 3rd IA is two years and 10 months but recent auctions have been delayed. The 2022/2023 BRA was originally scheduled for May 2019 but was delayed until June 2021. The First and Second IAs for 2022/2023 were not held and the Third IA was held in March 2022, just over nine months after the 2022/2023 BRA. The 2023/2024 BRA was held in June 2022 and the 2023/2024 Third IA was held in March 2023. The First and Second IAs for the 2023/2024 through 2027/2028 Delivery years were not held.

[164] PJM made changes to the load forecast model in December 2015. See Revision History (Revision 29) in *PJM Manual 19: Load Forecasting and Analysis* (December 5, 2019) for details. The revised model was first used for the 2019/2020 BRA held in May 2016 and has been used to determine the forecast peak load in all subsequent RPM auctions. The revised load forecast model was used for the Second IA and Third IA for 2017/2018, all incremental auctions for 2018/2019 and for all auctions for 2019/2020 and subsequent delivery years.

[165] For the 2025/2026 Delivery Year, PJM began using the marginal ELCC accreditation model and the pool wide EFORd was replaced with the pool wide Accredited UCAP factor in the reliability requirement calculation.

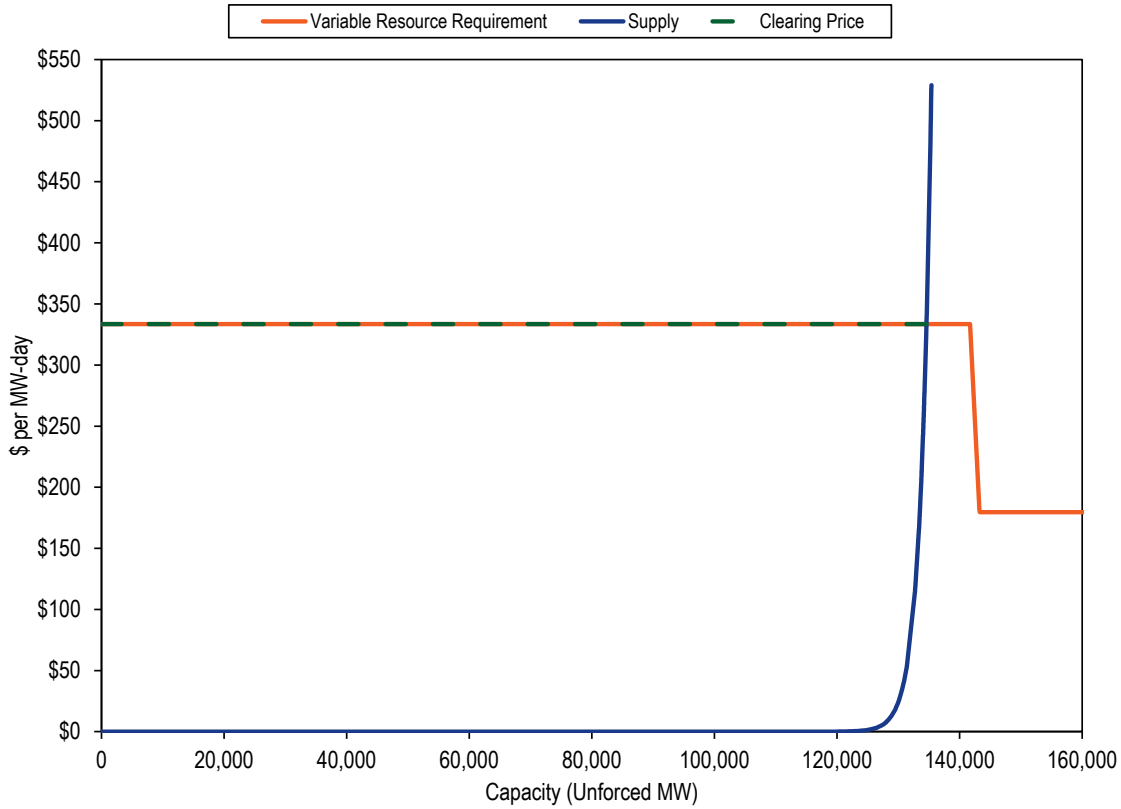
Table 25 DR statistics by LDA: 2026/2027 and 2027/2028 RPM Base Residual Auctions

	2026/2027 BRA			2027/2028 BRA			Change					
							Offered ICAP		Offered UCAP		Cleared UCAP	
LDA	Offered ICAP (MW)	Offered UCAP (MW)	Cleared UCAP (MW)	Offered ICAP (MW)	Offered UCAP (MW)	Cleared UCAP (MW)	MW	Percent	MW	Percent	MW	Percent
RTO	7,931.3	5,469.3	5,469.3	7,792.4	7,165.0	7,165.0	(138.9)	(1.8%)	1,695.7	31.0%	1,695.7	31.0%
MAAC	2,185.4	1,505.3	1,505.3	2,066.8	1,899.9	1,899.9	(118.6)	(5.4%)	394.6	26.2%	394.6	26.2%
EMAAC	883.5	608.1	608.1	861.0	791.5	791.5	(22.4)	(2.5%)	183.3	30.1%	183.3	30.1%
SWMAAC	431.4	297.2	297.2	416.3	382.6	382.6	(15.1)	(3.5%)	85.4	28.7%	85.4	28.7%
DPL South	49.2	33.9	33.9	46.3	42.6	42.6	(2.9)	(5.9%)	8.7	25.7%	8.7	25.7%
PSEG	260.0	179.0	179.0	254.8	234.1	234.1	(5.2)	(2.0%)	55.1	30.8%	55.1	30.8%
PSEG North	66.2	45.6	45.6	53.4	49.1	49.1	(12.8)	(19.3%)	3.5	7.8%	3.5	7.8%
Pepco	214.3	147.4	147.4	232.1	213.4	213.4	17.8	8.3%	66.0	44.8%	66.0	44.8%
ATSI	739.8	510.0	510.0	731.4	672.3	672.3	(8.4)	(1.1%)	162.3	31.8%	162.3	31.8%
ATSI Cleveland	109.7	75.7	75.7	110.7	101.7	101.7	1.0	0.9%	26.0	34.3%	26.0	34.3%
ComEd	1,383.3	954.4	954.4	1,594.2	1,466.5	1,466.5	210.9	15.2%	512.1	53.7%	512.1	53.7%
BGE	217.2	149.8	149.8	184.2	169.2	169.2	(32.9)	(15.2%)	19.4	12.9%	19.4	12.9%
PPL	463.5	319.8	319.8	458.4	421.6	421.6	(5.1)	(1.1%)	101.8	31.8%	101.8	31.8%
DAY	217.0	149.8	149.8	187.3	172.1	172.1	(29.7)	(13.7%)	22.3	14.9%	22.3	14.9%
DEOK	166.7	114.9	114.9	216.1	198.6	198.6	49.4	29.6%	83.7	72.8%	83.7	72.8%
Dominion	804.7	555.0	555.0	834.8	767.9	767.9	30.2	3.7%	212.9	38.4%	212.9	38.4%
JCPL	85.9	59.2	59.2	97.1	89.3	89.3	11.2	13.0%	30.1	50.8%	30.1	50.8%

Table 26 RPM imports: 2007/2008 through 2027/2028 RPM Base Residual Auctions

	UCAP (MW)					
	MISO		Non-MISO		Total Imports	
Base Residual Auction	Offered	Cleared	Offered	Cleared	Offered	Cleared
2007/2008	1,073.0	1,072.9	547.9	547.9	1,620.9	1,620.8
2008/2009	1,149.4	1,109.0	517.6	516.8	1,667.0	1,625.8
2009/2010	1,189.2	1,151.0	518.8	518.1	1,708.0	1,669.1
2010/2011	1,194.2	1,186.6	539.8	539.5	1,734.0	1,726.1
2011/2012	1,862.7	1,198.6	3,560.0	3,557.5	5,422.7	4,756.1
2012/2013	1,415.9	1,298.8	1,036.7	1,036.7	2,452.6	2,335.5
2013/2014	1,895.1	1,895.1	1,358.9	1,358.9	3,254.0	3,254.0
2014/2015	1,067.7	1,067.7	1,948.8	1,948.8	3,016.5	3,016.5
2015/2016	1,538.7	1,538.7	2,396.6	2,396.6	3,935.3	3,935.3
2016/2017	4,723.1	4,723.1	2,770.6	2,759.6	7,493.7	7,482.7
2017/2018	2,624.3	2,624.3	2,320.4	1,901.2	4,944.7	4,525.5
2018/2019	2,879.1	2,509.1	2,256.7	2,178.8	5,135.8	4,687.9
2019/2020	2,067.3	1,828.6	2,276.1	2,047.3	4,343.4	3,875.9
2020/2021	2,511.8	1,671.2	2,450.0	2,326.0	4,961.8	3,997.2
2021/2022	2,308.4	1,909.9	2,162.0	2,141.9	4,470.4	4,051.8
2022/2023	954.9	954.9	603.1	603.1	1,558.0	1,558.0
2023/2024	967.9	836.5	560.1	560.1	1,528.0	1,396.6
2024/2025	949.9	820.4	577.2	577.2	1,527.1	1,397.6
2025/2026	700.5	700.5	568.0	568.0	1,268.5	1,268.5
2026/2027	697.4	697.4	584.3	584.3	1,281.7	1,281.7
2027/2028	695.6	695.6	449.2	310.3	1,144.8	1,005.9

Figure 2 RTO market supply/demand curves: 2027/2028 RPM Base Residual Auction[166]



166 The supply curves presented in this report have all been smoothed using a statistical technique that fits a smooth curve to the underlying supply curve data while ensuring that the point of intersection between supply and demand curves is at the market clearing price. The supply curve includes all offered MW while the prices on the supply curve reflect the smoothing method. The final points on the supply curves generally do not match the price of the highest price offer as a result of the statistical fitting technique, while the MW do match. The smoothed curves are provided consistent with a FERC decision related to the release of RPM data. See, e.g., Motions to Cease and Desist and for Shortened Answer Period of the Independent Market Monitor for PJM (March 25, 2010) and Answer of PJM Interconnection, L.L.C. to Motion to Cease and Desist (March 30, 2010), filed in Docket No. ER09-1063-000, -003.