Capacity Market

In PJM, the capacity market exists to make the energy market work. Energy powers lights and computers and air conditioners. Capacity does not power anything. The capacity market needs to define the total MWh of energy that are needed to reliably serve load. The capacity market needs to provide the missing money. A primary reason to have a capacity market is that the energy market does not provide adequate net revenues to provide incentives for entry and for maintaining existing units. The obligation of load serving entities (LSEs) to own capacity equal to the peak demand plus a reserve margin was a longstanding feature of the PJM Operating Agreement before the creation of the PJM markets. The initial impetus to a capacity market in PJM, a request by the Pennsylvania PUC, was to support retail competition by ensuring that small new entrant competitive LSEs would have access to capacity at a competitive price without having to build capacity or purchase capacity bilaterally at monopoly prices. The first, daily capacity market, created in 1999, was replaced in 2007 by the current design based on the recognition that the energy market resulted in a shortfall in net revenues compared to that necessary to attract and retain adequate resources for the reliable operation of the energy market. The exogenous reliability requirement to have a level of capacity in excess of the level that would result from the operation of an energy market alone reduces the level and volatility of energy market prices and reduces the duration of high energy market prices. This reduces net revenue to generation owners which reduces the incentive to invest. But in order for the PJM markets to be self sustaining, the net revenues from PJM energy, ancillary services and capacity markets must be adequate for those resources. That adequacy requires a capacity market. The capacity market plays the essential role of equilibrating the revenues necessary to incent competitive entry and exit of the resources needed for reliability, with the revenues from the energy and ancillary services markets.

The only goal of the detailed design of the capacity market is to ensure that the opportunity for that revenue equilibration exists through a competitive process.

The Capacity Performance (CP) design was a radical change to the capacity market paradigm. The CP design is a failed experiment. The fundamental mistake of the CP design was to attempt to recreate energy market incentives in the capacity market. The CP model was an explicit attempt to bring energy market shortage pricing into the capacity market design. The CP model was designed on the assumption that shortage prices in the energy market were not high enough and needed to be increased via the capacity market.

The challenge is to create a straightforward capacity market design that meets the simple objectives of a capacity market and that does not become a vehicle for energy market incentives or rent seeking or attempts to limit the ways in which specific types of generation participate in PJM markets. Energy market incentives should remain in the energy market.

The PJM market design is based on the must offer and must buy obligations of capacity resources. All capacity resources, with the current exception of intermittent and storage capacity, are required to offer into the capacity auctions. All LSEs must buy capacity equal to their peak load plus a reserve margin.

Each organization serving PJM load must meet its capacity obligations through the PJM Capacity Market, where load serving entities (LSEs) must pay the locational capacity price for their zone. LSEs can also construct generation and offer it into the capacity market, enter into bilateral contracts, develop demand resources and energy efficiency (EE) resources and offer them into the capacity market, or construct transmission upgrades and offer them into the capacity market.

The Market Monitoring Unit (MMU) analyzed market structure, participant conduct and market performance in the PJM Capacity Market, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.[1] The conclusions are a result of the MMU's evaluation of the 2024/2025 Base Residual Auction.[2] The 2024/2025 RPM Base Residual Auction was conducted in 2022, but the results were not

1 The values stated in this report for the RTO and LDAs refer to the aggregate level including all nested LDAs unless otherwise specified. For example, RTO values include the entire PJM market and all LDAs. Rest of RTO values are RTO values net of nested LDA values.

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

posted until February 27, 2023, due to an issue with the DPL South reliability requirement. The Commission orders addressing the issue with the DPL South reliability requirement were reversed on appeal.[3] Commission action on the matter is pending. As a result, final prices for the 2024/2025 Base Residual Auction have not been approved.

Table 5-1 The capacity market results were competitive

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

- The aggregate market structure was evaluated as not competitive. For almost all auctions held from 2007 to the present, the PJM Capacity Market failed the three pivotal supplier test (TPS), which is conducted at the time of the auction.[4] Structural market power is endemic to the capacity market.
- The local market structure was evaluated as not competitive. For almost every auction held, all LDAs have failed the TPS test, which is conducted at the time of the auction.[5]
- Participant behavior was evaluated as competitive in the 2024/2025 BRA after the Commission order addressed the definition of the market seller offer cap by eliminating the net CONE times B offer cap and establishing a competitive market seller offer cap of net ACR, effective September 2, 2021.[6] Market power mitigation measures were applied when the capacity market seller failed the market power test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price.
- Market performance was evaluated as competitive based on the 2024/2025 Base Residual Auction after the Commission order eliminating the net CONE times B offer cap and establishing a competitive market seller offer cap of net ACR, effective September 2, 2021. Although structural market power exists in the capacity market, a competitive outcome can result from the application of market power mitigation rules.
- Market design was evaluated as mixed because while there are many positive features of the Reliability Pricing Model (RPM) design and the capacity performance modifications to RPM, there are several features of the RPM design which still threaten competitive outcomes. These include the definition of DR which permits inferior products to substitute for capacity, the replacement capacity issue, the definition of unit offer parameters, and the inclusion of imports which are not substitutes for internal capacity resources.
- As a result of the fact that the capacity market design was found to be not just and reasonable by FERC and a final market design had not been approved, the 2022/2023 Base Residual Auction was delayed and held in May 2021, and for a number of additional reasons, the 2023/2024 Base Residual Auction was delayed and held in June 2022, the 2024/2025 Base Residual Auction was delayed and held in December 2022, and first and second incremental auctions for the 2022/2023 through 2028/2029 Delivery Years are canceled if within 10 months of the revised BRA schedule.[7]

3 See PJM Power Providers Grp. v. FERC, 96 F.4th 390 (3d Cir. 2024).

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

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

6 176 FERC ¶ 61,137 (2021), *order denying reh'g*, 178 FERC ¶ 61,121 (2022), *appeal denied*, EPSA, et al. v. FERC, Case No. 21-1214, et al. (DC Cir. October 10, 2023). The Commission recognized the market power problem and issued an order correcting the PJM tariff, eliminating the prior offer cap and establishing a competitive market seller offer cap set at net ACR, effective September 2, 2021.

7 174 FERC ¶ 61,036 (2021), 177 FERC ¶ 61,050 (2021), 177 FERC ¶ 61,209 (2021), 183 FERC ¶ 61,172 (2023), 186 FERC ¶ 61,144 (2024).

Overview

RPM Capacity Market

Market Design

The Reliability Pricing Model (RPM) Capacity Market is a forward looking, annual, locational market, with a must offer requirement for Existing Generation Capacity Resources and a must buy requirement for load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand side resources.[8] Currently, intermittent and storage resources are exempt from the must offer requirement, although that is not a viable long term design element for the capacity market. The fundamental goal of the must offer requirement, which has been in place since the beginning of the capacity market in 1999, is to ensure that the capacity market works, and therefore that the energy market works, based on the inclusion of all demand and all supply, to ensure open access to the transmission system, and to prevent the exercise of market power via withholding of capacity supply. If some resources hold CIRs (capacity interconnection rights) that provide access to the transmission system required for the deliverability of energy, but do not offer, those resources are exercising market power by blocking access to the transmission system that could be used by a resource willing to offer into the capacity market.

Under RPM, capacity obligations are annual.[9] Base Residual Auctions (BRA) are held for delivery years that are three years in the future. First, Second and Third Incremental Auctions (IA) are held for each delivery year.[10] First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[11] A Conditional Incremental Auction may be held if there is a need to procure additional capacity resulting from a delay in a planned large transmission upgrade that was modeled in the BRA for the relevant delivery year.[12]

8 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in this report and include all capacity within the PJM footprint.
9 Effective for the 2020/2021 and subsequent delivery years, the RPM market design incorporated seasonal capacity resources. Summer period and winter period capacity must be matched either through commercial aggregation or through the optimization in equal MW amounts in the LDA or the lowest common parent LDA.
10 See 126 FERC ¶ 61,275 at P 86 (2009).
11 See Letter Order, FERC Docket No. ER10-366-000 (January 22, 2010).
12 See 126 FERC ¶ 61,275 at P 88 (2009). There have been no Conditional Incremental Auctions.

The 2024/2025 RPM Third Incremental Auction was conducted in the first three months of 2024. The 2024/2025 RPM Base Residual Auction was conducted in 2022, but the results were not posted until February 27, 2023, due to an issue with the DPL South reliability requirement.[13] [14] The 2025/2026 RPM Base Residual Auction was scheduled for June 2023 but postponed until June 2024 and then postponed again until July 2024.[15]

The Commission orders addressing the issue with the DPL South reliability requirement were reversed on appeal, creating uncertainty about the auction results.[16] PJM proposed to the Commission that PJM withdraw the auction results under the rejected rules, calculate the results under the prior flawed rules, and rerun an incremental auction to adjust to the new results.[17] PJM load filed a complaint requesting that the auction results be preserved in order to ensure just and reasonable prices going forward.[18] Commission action on the matter is pending.

RPM prices are locational and may vary depending on transmission constraints and local supply and demand conditions.[19] Existing generation that qualifies as a capacity resource must be offered into RPM auctions, except for resources owned by entities that elect the fixed resource requirement (FRR) option, and, as a result of Capacity Performance rule changes, except for intermittent and capacity storage resources including hydro. Participation by LSEs is mandatory, except for those entities that elect the FRR option. There is an administratively determined demand curve that defines scarcity pricing levels and that, with the supply curve derived from capacity offers, determines market prices in each BRA. RPM rules provide performance incentives for generation, including the requirement to submit generator outage data and the linking of capacity payments to the level of unforced capacity. The experience with Winter Storm Elliott (Elliott) has made clear that the extremely high penalties created in the

13 On December 23, 2022, PJM filed revisions to the PJM market rules in Docket No. ER23-729-000 and contemporaneously filed a complaint in Docket No. EL23-19-000 seeking the same revisions. By order issued February 21, 2023, PJM's revisions were accepted and the complaint was dismissed as moot. 182 FERC ¶ 61,109.
14 See the "Analysis of the 2024/2025 RPM Base Residual Auction," <https://www.monitoringanalytics.com/reports/Reports/2023/IMM_Analysis_of_the_20242025_RPM_Base_Residual_Auction_20231030.pdf> (October 30, 2023).
15 See 183 FERC ¶ 61,172 (2023) and 186 FERC ¶ 61,144 (2024).
16 See PJM Power Providers Grp. v. FERC, 96 F.4th 390 (3rd Cir. 2024).
17 Petition Under Rule 207 of PJM Interconnection, L.L.C. for Order Confirming 2024/2025 Delivery Year Capacity Commitment Rules, Request for Order by May 6, 2024, and Request for Shortened 10-Day Comment Period, FERC Docket No. ER23-729-002 (Mar. 29, 2024),
18 See Conditional Complaint of the PJM Load Parties, FERC Docket No. EL24-104-000 (April 11, 2024).
19 Transmission constraints are local capacity import capability limitations (low capacity emergency transfer limit (CETL) margin over capacity emergency transfer objective (CETO)) caused by transmission facility limitations, voltage limitations or stability limitations.

CP model are not an effective incentive. Under RPM there are explicit market power mitigation rules that define structural market power, that define offer caps based on the marginal cost of capacity, and that have flexible criteria for competitive offers by new entrants. Market power mitigation is effective only when these definitions are up to date and accurate. Demand resources and energy efficiency resources may be offered directly into RPM auctions and receive the clearing price without mitigation.

Market Structure

- **RPM Installed Capacity.** In the first three months of 2024, RPM installed capacity increased 74.1 MW or 0.0 percent, from 178,375.0 MW on January 1, to 178,449.1 MW on March 31. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- **Reserves.** For the 2024/2025 RPM Base Residual Auction, the sum of cleared MW that were considered categorically exempt from the must offer requirement and the cleared MW of DR is 16,403.2 MW, or 97.2 percent of required reserves and 65.7 percent of total reserves. These results suggest that the required reserve margin and the actual reserve margin be considered carefully along with the obligations of the resources that the reserve margin assumes will be available.
- **RPM Installed Capacity by Fuel Type.** Of the total installed capacity on March 31, 2024, 49.8 percent was gas; 21.2 percent was coal; 18.0 percent was nuclear; 4.2 percent was hydroelectric; 2.4 percent was oil; 1.9 percent was wind; 0.4 percent was solid waste; and 2.1 percent was solar.
- **Market Concentration.** In the 2024/2025 RPM Third Incremental Auction, all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[20] Offer caps were applied to all sell offers for resources which were subject to mitigation when the capacity market seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[21] [22] [23]
- **Imports and Exports.** Of the 1,527.1 MW of imports in the 2024/2025 RPM Base Residual Auction, 1,397.6 MW cleared. Of the cleared imports, 820.4 MW (58.7 percent) were from MISO.
- **Demand Resources.** Committed DR was 7,707.9 MW for June 1, 2023, as a result of cleared capacity for demand resources in RPM auctions for the 2023/2024 Delivery Year (8,174.1 MW) less replacement capacity (466.2 MW).
- **Energy Efficiency Resources.** Committed EE was 5,891.1 MW for June 1, 2023, as a result of cleared MW in RPM auctions for the 2023/2024 Delivery Year (5,896.4 MW) less replacement MW (5.3 MW).

Market Conduct

- **2024/2025 RPM Third Incremental Auction.** Of the 316 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for seven generation resources (2.2 percent).

Market Performance

- The 2024/2025 RPM Third Incremental Auction was conducted in the first three months of 2024. The weighted average capacity price for the 2023/2024 Delivery Year is $42.01 per MW-day, including all RPM auctions for the 2023/2024 Delivery Year. The weighted average capacity price for the 2024/2025 Delivery Year is $42.53 per MW-day, including all RPM auctions for the 2024/2025 Delivery Year.
- For the 2023/2024 Delivery Year, RPM annual charges to load are $2.2 billion.
- In the 2024/2025 RPM Base Residual Auction, the market performance was determined to be competitive.

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

21 See OATT Attachment DD § 6.5.

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

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

Part V Reliability Service (RMR)

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

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd in the first three months of 2024 was 4.5 percent, a decrease from 5.2 percent in the first three months of 2023.[24]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor in the first three months of 2024 was 87.9 percent, an increase from 86.3 percent in the first three months of 2023.

Recommendations[25]

Definition of Capacity

- The MMU recommends elimination of the key remaining components of the CP model because they interfere with competitive outcomes in the capacity market and create unnecessary complexity and risk. (Priority: High. First reported Q3, 2022. Status: Not adopted.)
- The MMU recommends the enforcement of a consistent definition of capacity resources. The MMU recommends that the tariff requirement to be a physical resource be enforced and enhanced. The requirement to be a physical resource should apply at the time of auctions and should also constitute a commitment to be physical in the relevant delivery year. The requirement to be a physical resource should be applied to all resource types, including planned generation, demand resources, energy efficiency, and imports.[26] [27] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that DR providers be required to have a signed contract with specific customers for specific facilities for specific levels of DR at least six months prior to any capacity auction in which the DR is offered. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that Energy Efficiency Resources (EE) not be included in the capacity market because PJM's load forecasts have accounted for EE since the 2016 load forecast for the 2019/2020 delivery year, and the tariff rationale for inclusion no longer exists.[28] (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that intermittent resources, including storage, not be permitted to offer capacity MW based on energy deliveries that exceed their defined deliverability rights (CIRs). Only energy output for such resources at or below the designated CIR/deliverability level should be recognized in the definition of derated capacity (e.g. ELCC). Correctly defined ELCC derating factors are lower than the CIRs required to meet those derating factors. (Priority: High. First reported 2021. Status: Adopted 2023.)
- The MMU recommends that PJM require all market participants to meet their deliverability requirements under the same rules. PJM should end the practice of giving away, only to intermittent resources, winter CIRs that appear to exist because other resources paid for the supporting network upgrades. (Priority: High. First reported 2017. Status: Not adopted.)[29]
- The MMU recommends that the must offer rule in the capacity market apply to all capacity resources. There is no reason to exempt intermittent and capacity storage resources, including hydro, and demand resources from the must offer requirement. The same rules should apply to all capacity resources in order to ensure open access to the transmission

24 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM generator availability data systems (GADS) database. Data was downloaded from the PJM GADS database on April 24, 2024. EFORd data presented in state of the market reports may be revised based on data submitted after the publication of the reports as generation owners may submit corrections at any time with permission from PJM GADS administrators.

25 The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues. These recommendations have been made in public reports. See Table 5-2.

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

27 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).

28 "PJM Manual 19: Load Forecasting and Analysis," § 3.2 Development of the Forecast, Rev. 36 (Nov. 15, 2023).

29 This recommendation was first made in the 2020/2021 BRA report in 2017. See the "Analysis of the 2020/2021 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Analysis_of_the_20202021_RPM_BRA_20171117.pdf> (November 11, 2017).

system and prevent the exercise of market power through withholding. (Priority: High. First reported 2021. Status: Not adopted.)

- The MMU recommends that PJM require all market sellers of proposed generation capacity resources, including thermal and intermittent, to submit a binding notice of intent to offer at least six months prior to the base residual auction. This is consistent with the overall MMU recommendation that all capacity resources have a must offer obligation in the capacity market auctions. (Priority: High. First reported Q3 2023. Status: Partially adopted.)

Market Design and Parameters

- The MMU recommends that PJM reevaluate the shape of the VRR curve. The shape of the VRR curve directly results in load paying substantially more for capacity than load would pay with a vertical demand curve. More specifically, the MMU recommended that the VRR curve be rotated half way towards the vertical demand curve at the reliability requirement in the 2022 Quadrennial Review. (Priority: High. First reported 2021. Status: Partially adopted.)
- The MMU recommends that the maximum price on the VRR curve be defined as net CONE. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that the test for determining modeled Locational Deliverability Areas (LDAs) in RPM be redefined. A detailed reliability analysis of all at risk units should be included in the redefined model. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM clear the capacity market based on nodal capacity resource locations and the characteristics of the transmission system consistent with the actual electrical facts of the grid. Absent a fully nodal capacity market clearing process, the MMU recommends that PJM use a non-nested model with all LDAs modeled including VRR curves for all LDAs. Each LDA requirement should be met with the capacity resources located within the LDA and exchanges from neighboring LDAs up to the transmission limit. LDAs should be allowed to price separate if that is the result of the LDA supply curves and the transmission constraints between LDAs. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that the net revenue offset calculation used by PJM to calculate the net Cost of New Entry (CONE) and net ACR be based on a forward looking calculation of expected energy and ancillary services net revenues using historical net revenues that are scaled based on forward prices for energy and fuel. (Priority: High. First reported 2014. Status: Not adopted.)[30]
- The MMU recommends that PJM reduce the number of incremental auctions to a single incremental auction held three months prior to the start of the delivery year and reevaluate the triggers for holding conditional incremental auctions. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM not sell back any capacity in any IA procured in a BRA. If PJM continues to sell back capacity, the MMU recommends that PJM offer to sell back capacity in incremental auctions only at the BRA clearing price for the relevant delivery year. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM not buy any capacity in any IA if PJM has already procured excess reserves. (Priority: Medium. First reported 2023. Status: Not adopted.)
- The MMU recommends changing the RPM solution method to explicitly incorporate the cost of uplift (make whole) payments in the objective function. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that the Fixed Resource Requirement (FRR) rules, including obligations and performance requirements, be revised and updated to ensure that the rules reflect current market realities and that FRR entities do not unfairly take advantage of those customers paying for capacity in the PJM capacity market. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that the value of CTRs be defined by the total MW cleared in the capacity market, the internal MW cleared and the imported

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

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

- The MMU recommends that the market clearing results be used in settlements rather than the reallocation process currently used, or that the process of modifying the obligations to pay for capacity be reviewed. (Priority: Medium. First reported 2021. Status: Not adopted.)[31]
- The MMU recommends that PJM improve the clarity and transparency of its CETL calculations. The MMU also recommends that CETL for capacity imports into PJM be based on the ability to import capacity only where PJM capacity exists and where that capacity has a must offer requirement in the PJM Capacity Market. (Priority: Medium. First reported 2021. Status: Partially adopted 2022.)

Offer Caps, Offer Floors, and Must Offer

- The MMU recommends using the lower of the cost or price-based energy market offer to calculate energy costs in the calculation of the historical net revenues which are an offset to gross ACR in the calculation of unit specific capacity resource offer caps based on net ACR. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends use of the MMU's Sustainable Market Rule (SMR) in order to protect competition in the capacity market from nonmarket revenues.[32] (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that, as part of the MOPR unit specific standard of review, all projects be required to use the same basic modeling assumptions. That is the only way to ensure that projects compete on the basis of actual costs rather than on the basis of modeling assumptions.[33] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that modifications to existing resources be subject to market power related offer caps or MOPR offer floors and not be treated as new resources and therefore exempt. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the RPM market power mitigation rule be modified to apply offer caps in all cases when the three pivotal supplier test is failed and the sell offer is greater than the offer cap. This will ensure that market power does not result in an increase in uplift (make whole) payments for seasonal products. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that any combined seasonal resources be required to be in the same LDA and at the same location, in order for the energy market and capacity market to remain synchronized and reliability metrics correctly calculated. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that the definition of avoidable costs in the tariff be corrected to be consistent with the economic definition. Avoidable costs are costs that are neither short run marginal costs, like fuel or consumables, nor fixed costs like depreciation and rate of return. Avoidable costs are the marginal costs of capacity and therefore the competitive offer level for capacity resources and therefore the market seller offer cap. Avoidable costs are the marginal costs of capacity whether a new

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

32 Brief of the Independent Market Monitor for PJM, Docket No. EL16-49, ER18-1314-000,-001; EL18-178 (October 2, 2018).

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

resource or an existing resource. (Priority: Medium. First reported 2017. Status: Not adopted.)[34]

- The MMU recommends that major maintenance costs be included in the definition of avoidable costs and removed from energy offers because such costs are avoidable costs and not short run marginal costs. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that capacity market sellers be required to explicitly request and support the use of minimum MW quantities (inflexible sell offer segments) and that the requests only be permitted for defined physical reasons. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that relatively small proposed increases in the capability of a Generation Capacity Resource be treated as an existing resource and subject to the corresponding market power mitigation rules and no longer be treated as planned and exempt from offer capping. (Priority: Medium. First reported 2012. Status: Not adopted.)[35]

Performance Incentive Requirements of RPM

- The MMU recommends that any unit not capable of supplying energy equal to its day-ahead must offer requirement (ICAP) be required to reflect an appropriate outage. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that retroactive replacement transactions associated with a failure to perform during a PAI not be allowed and that, more generally, retroactive replacement capacity transactions not be permitted. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that there be an explicit requirement that capacity resource offers in the day-ahead energy market be competitive, where competitive is defined to be the short run marginal cost of the units, including flexible operating parameters. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that Capacity Performance resources be required to perform without excuses. Resources that do not perform should not be paid regardless of the reason for nonperformance. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that the market data posting rules be modified to allow the disclosure of expected performance, actual performance, shortfall and bonus MW during a PAI by area without the requirement that more than three market participants' data be aggregated for posting. (Priority: Low. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM require actual seasonal tests as part of the Summer/Winter Capability Testing rules, that the number of tests be limited, and that the ambient conditions under which the tests are performed be defined to reflect seasonal extreme conditions. (Priority: Medium. First reported Q1 2022. Status: Not adopted.)
- The MMU recommends that PJM select the time and day that a unit undergoes Net Capability Verification Testing, not the unit owner, and that this information not be communicated in advance to the unit owner. (Priority: Medium. First reported Q2 2022. Status: Not adopted.)

Capacity Imports and Exports

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

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

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

Deactivations/Retirements

- The MMU recommends that the notification requirement for deactivations be extended from 90 days prior to the date of deactivation to 12 months prior to the date of deactivation and that PJM and the MMU be provided 60 days rather than 30 days to complete their reliability and market power analyses. (Priority: Low. First reported 2012. Status: Partially adopted.)
- The MMU recommends elimination of both the cost of service recovery rate option and the deactivation avoidable cost rate option for providing Part V reliability service (RMR), and their replacement with clear language that provides for the recovery of 100 percent of the actual incremental costs required to operate to provide the service plus an incentive. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that units recover all and only the incremental costs, including incremental investment costs without a cap, required to provide Part V reliability service (RMR service) that the unit owner would not have incurred if the unit owner had deactivated its unit as it proposed, plus a defined incentive payment. Customers should bear no responsibility for paying previously incurred (sunk) costs, including a return on or of prior investments. (Priority: High. First reported 2010. Status: Not adopted.)
- The MMU recommends that the same reliability standard be used in capacity auctions as is used by PJM transmission planning. One result of the current design is that a unit may fail to clear in a BRA, decide to retire as a result, but then be found to be needed for reliability by PJM planning and paid under Part V of the OATT (RMR) to remain in service while transmission upgrades are made. (Priority: High. First reported Q3 2023. Status: Not adopted.)
- The MMU recommends that units that are paid under Part V of the OATT (RMR) not be included in the calculation of CETO or reliability in the relevant LDA, in order to ensure that the capacity market price signal reflects the appropriate supply and demand conditions. (Priority: High. First reported Q3 2023. Status: Not adopted.)
- The MMU recommends that all CIRs be returned to the pool of available interconnection capability on the retirement date of generation resources in order to facilitate competitive entry into the PJM markets, open access to the transmission system and maintain the priority order defined by the queue process. (Priority: High. First reported Q3 2023. Status: Not adopted.)

Conclusion

The analysis of PJM Capacity Markets begins with market structure, which provides the framework for the actual behavior or conduct of market participants. The analysis examines participant behavior within that market structure. In a competitive market structure, market participants are constrained to behave competitively. In a market with endemic structural market power like the PJM Capacity Market, effective market power mitigation rules are required in order to constrain market participants to behave competitively. The analysis examines market performance, measured by price and the relationship between price and marginal cost, that results from the interaction of market structure and participant behavior.

The 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 can and do 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 in future capacity markets, or in other 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. The demand for capacity includes expected peak load plus a reserve margin, and points on the demand curve, called the Variable Resource Requirement (VRR) curve, exceed peak load plus the reserve margin. The shape of the VRR curve results in the purchase of excess capacity and higher payments by customers. The impact of the VRR curve shape used in the 2024/2025 BRA compared to a vertical demand curve was a significant increase in customer payments for load as a result of buying more capacity than needed for reliability and paying a price above the competitive level as a result. The defined reliability goal is to have total supply greater than or equal to the defined demand for capacity. The level of purchased demand under RPM has generally exceeded expected peak load plus the target reserve margin, resulting in reserve margins that exceed the target. Demand for capacity is almost entirely inelastic because the market rules require loads to purchase their share of the system capacity requirement. The VRR demand curve is everywhere inelastic. The result is that any supplier that owns more capacity than the typically small difference between total supply and the defined demand is individually pivotal and therefore has structural market power. Any supplier that, jointly with two other suppliers, owns more capacity than the difference between supply and demand either in aggregate or for a local market is jointly pivotal and therefore has structural market power.

For the 2024/2025 RPM Base Residual Auction, the level of committed demand resources (8,083.9 MW UCAP) almost equals the entire level of excess capacity (8,086.8 MW). This is consistent with PJM effectively not relying on demand response for reliability in actual operations. The excess is a result of the flawed rules permitting the participation of inferior demand side resources in the capacity market. Maintaining the persistent excess has meant that PJM markets have never experienced the results of reliance on demand side resources as part of the required reserve margin, rather than as excess above the required reserve margin. PJM markets have never experienced the implications of the definition of demand side resources as a purely emergency capacity resource that triggers a PAI whenever called and can set prices at shortage levels simply by being called, when demand side resources are a significant share of required reserves. Rule changes implemented following Winter Storm Elliott eliminated the automatic triggering of a PAI when demand resources are called.[36]

The market design for capacity leads 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. 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. 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.[37] [38] 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 a noncompetitive outcome. The market power rules were corrected by the Commission in an order issued on September 2, 2021, but the modified market power rules were not implemented in the 2022/2023 BRA.[39] [40] The result was that capacity market prices were above the competitive level in the 2022/2023 BRA. In addition, the inclusion of offers that were not consistent with the defined terms of the Minimum Offer Price Rule (MOPR) based on the MMU's review, but were accepted by PJM, had a significant impact on the auction results in the 2022/2023 BRA.

The implementation of the market power mitigation rules effective September 2, 2021, that corrected the definition of the market seller offer cap in the 2023/2024 BRA resolved the market power issues from the prior two BRAs. The results of the 2023/2024 BRA and the 2024/2025 BRA were competitive.

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.

36 Letter Order, FERC Docket No. ER23-1996-001 (October 2, 2023).

37 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).

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

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

40 176 FERC ¶ 61,137 (2021); 178 FERC ¶ 61,121 (2022); *appeal denied*, Vistra Corp., et al. v. FERC, Case No. 21-1214 (D.C. Cir. October 10, 2023); *cert. pending*.

The definition of the market seller offer cap was changed with the introduction of the Capacity Performance (CP) rules, from offer caps based on the marginal cost of capacity to offer caps based on Net CONE. But the CP market seller offer cap was based on strong assumptions that are not correct. The derivation of the CP market seller offer cap was based on PJM's assertion that the target price of the capacity market should be Net CONE, and simply assumed the answer. The logic underlying the CP market seller offer cap was circular. The CP market seller offer cap was incorrectly and significantly overstated as a result.

PJM's filing of the CP design made clear that PJM was abandoning offer caps that were based on verifiable calculations of the marginal cost of providing capacity in favor of an approach that explicitly relied on wishful thinking about competitive forces resulting in competitive offers, despite the fact that the filing elsewhere recognized the high levels of concentration and the need to protect against market power in the capacity market.[41] PJM ignored the economic logic of marginal cost. PJM simply asserted that Net CONE was the target clearing price of the capacity market. PJM's filing explicitly stated that "By design, over time the marginal offer needed to clear the market will be priced at Net CONE, and all other resources that clear the market will be compensated at that Net CONE price."[42] PJM did not include a derivation of the offer cap in its CP filing, but simply asserted that Net CONE was the definition of a competitive offer.[43] There was not a single reference to opportunity cost as the basis for the market seller offer cap in the PJM filing.

In subsequent filings, PJM included the mathematical derivation of the market seller offer cap.[44] But the circular logic of the derivation inevitably concluded that Net CONE times B was the competitive offer. There were two key assumptions that led to that result. The derivation started by assuming that Net CONE was the target clearing price for the capacity market. PJM stated, in explaining the penalty rate, "Net CONE is the proper measure of the value of capacity."[45] That assumption/assertion was the basis for using Net CONE as the penalty rate. The penalty rate, adjusted for the reduced obligation defined by B, became the market seller offer cap. In addition to assuming the answer by setting the penalty rate based on net CONE, the second key counterfactual assumption was that capacity resources have the ability to costlessly switch between capacity resource status and energy only status.

The mathematical derivation also included some additional unsupported and incorrect assumptions: there are a reasonably expected number of PAI; the number of PAI used in the calculation of the nonperformance charge rate is the same as the expected PAI (360); the number of performance intervals that define the total payments must equal the denominator of the performance penalty rate; the bonus payment rate for units that overperform equals the penalty rate for units that underperform; and penalties are imposed by PJM for all cases of noncompliance as defined in the tariff and there are no excuses.

Those assumptions were not even close to being correct for the 2022/2023 BRA and Net CONE times B was not the correct offer cap as a result.

The MMU supported the modified CP filing and prepared the mathematical appendix.[46] However, after evaluating the offer behavior and results of the capacity market auctions under CP and the actual PAI evidence and the failure to include updated PAI data in the definition of the offer cap, it became clear to the MMU that the CP model was a mistake.[47] The market seller offer cap of Net CONE times B was ultimately a failed experiment based on the third demonstrably false assumption that competitive forces in the PJM Capacity Market would produce competitive outcomes despite an offer cap that was above the competitive level. The structure of the PJM Capacity Market is not competitive and the purpose of market power mitigation is to produce competitive results despite that fact. The Net CONE times B offer cap assumed competition where it did not exist and led to noncompetitive outcomes and led to customers being overcharged by a combined $1.454 billion in the

41 See "Reforms to the Reliability Pricing Market ("RPM") and Related Rules in the PJM Open Access Transmission Tariff ("Tariff") and Reliability Assurance Agreement Among Load Serving Entities ("RAA")," ("CP Filing"), Docket No. ER15-623, December 12, 2014; See, for example, page 54 and page 58.

42 See page 55 of CP Filing.

43 PJM did not multiply Net CONE by B in its CP filing of December 12, 2014.

44 For a detailed derivation, *see* Errata to February 25, 2015 Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM Interconnection, L.L.C., Docket No. ER15-623, et al. (February 27, 2015).

45 See page 43 of CP Filing.

46 See PJM Response to Deficiency Notice, ER15-623-001, et al. (April 10, 2015); Comments of the Independent Market Monitor for PJM, Docket No. ER15-623-001, et al. (April 15, 2015).

47 Brief of the Independent Market Monitor for PJM, EL19-47-000 (April 28, 2021); see also Comments of the Independent Market Monitor, Docket No. ER15-623, EL15-29 and EL19-47 (December 13, 2019); Comments of the Independent Market Monitor, Docket No. ER15-623, EL15-29 and EL19-47 (December 17, 2020).

2021/2022 and 2022/2023 BRAs.[48] The logical circularity of the argument as well as the fact that key assumptions are incorrect, means that the CP market seller offer cap was not based on economics or logic or math.

The correct definition of a competitive offer is the marginal cost of capacity, net ACR, where ACR includes an explicit accounting for the costs of mitigating risk, including the risk associated with capacity market nonperformance penalties, and the relevant costs of acquiring fuel, including natural gas. In response to a complaint filed by the MMU, the Commission replaced the Net CONE times B market seller offer cap with an ACR offer cap in the September 2nd Order.[49] [50]

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). This is a positive performance incentive based on the market price of capacity rather than a penalty based on an arbitrary assumption. This would mean that capacity resources are paid to provide energy and reserves based on their full ICAP and are not paid a bonus for doing so. The reduced payments for capacity would directly reduce customers' bills for capacity. This would also end the pretense that there will be penalty payments to fund bonus payments. This would also end the need for complex CPQR calculations based on the penalty rate and assumptions about the number and timing of PAI. CP has not worked as the theory suggested. PAI events are high impact low probability events. The failure of the PAI incentives to prevent a very high level of outages illustrates the weakness of incentives based on this type of event. The actual performance standards were unacceptably weakened in the CP model. The standard of performance in the CP model is B * (1 – EFORd) for a unit, where B is the balancing ratio and EFORd is the forced outage rate. For example, if B were 80 percent, the actual required performance for a unit with a 10 percent EFORd would be only 72 percent of ICAP (.80 * .90). For units with high historical forced outage rates, the required performance is even lower. The obligation to perform should equal the full ICAP value of a unit, consistent with the associated must offer obligation in the energy market for capacity resources.

The fundamental mistake of the CP design was to attempt to recreate energy market incentives in the capacity market. The CP model was an explicit attempt to bring energy market shortage pricing into the capacity market design. The CP model was designed on the unsupported assumption that shortage prices in the energy market were not high enough and needed to be increased via the capacity market. The CP design focused on a small number of critical hours (performance assessment hours or PAH, translated into five minute intervals as PAI) and imposed large penalties on generators that failed to produce energy only during those hours. But the use of capacity market penalties rather than energy market incentives created a new risk. While there are differences of opinion about how to value the risk, this CP risk is not risk that is fundamental to the operation of a wholesale power market. This is risk created by the CP design in order, in unsupported concept, to provide an incentive to produce energy during high demand hours that is even higher than the energy market incentive, amplified by an operating reserve demand curves (ORDC). The risk created by CP is not limited to risk for individual generators, but extends to the viability of the market. If penalties create bankruptcies that threaten the viability of required energy output from the affected units, there is a risk to the market.

The Commission rejected a more recent attempt by PJM to undermine the Market Seller Offer Cap rules in its two part ELCC filing by order issued February 6, 2024.[51]

48 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>.

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

50 176 FERC ¶ 61,137 (2021), *order on reh'g*, 178 FERC ¶ 61,121 (2022), *appeal denied*, EPSA, et al. v. FERC, Case No. 21-1214, et al. (DC Cir. October 10, 2023).

51 186 FERC ¶ 61,097, *reh'g denied*, 187 FERC ¶ 62,016 (2024).

Winter storm Elliott provided the first real test of the CP design. Elliott showed that the CP design 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 that included Elliott. In addition, it has been clear from prior, very brief and local PAI events that the process of defining excuses and retroactive replacement transactions, imposing penalties and paying bonuses is complex and very difficult to administer, and includes substantial subjective elements. PAI incentives are not effective market incentives. PAI incentives are administrative and nonmarket incentives that are not compatible with an effective market design. The energy market clearing, in contrast, is transparent and efficient and timely. While there are issues with the details of energy market pricing that must be addressed, including shortage pricing, the energy market does not include or create the significant and long lasting uncertainty created by the PAI rules as exhibited most dramatically by the results of Elliott. The PAI design creates an administrative process that adds unacceptable uncertainty to the process and that can never approach the effectiveness of the energy market in providing price signals and timely settlement.

The MMU recommends that the must offer rule in the capacity market apply to all capacity resources.[52] Prior to the implementation of the capacity performance design, all existing capacity resources, except DR, were subject to the must offer requirement. There is no reason to exempt intermittent and capacity storage resources, including hydro, 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, and therefore that the energy market works, based on the inclusion of all demand and all supply, to ensure competitive entry, to ensure open access to the transmission system, and to prevent the exercise of market power via withholding of capacity supply. The purpose of the must offer requirement is also to ensure equal access to the transmission system through CIRs (capacity interconnection rights). If a resource has CIRs that provide access to the transmission system required for the deliverability of energy, but do not offer, those resources are exercising market power by blocking access to the transmission system that could be used by a resource willing to offer into the capacity market. For these reasons, existing resources are required to return CIRs to the market within one year after retirement. The MMU recommends that resources return CIRs to the market on the day of retirement. The same logic should be applied to intermittent and storage resources. The failure to apply the must offer requirement will create increasingly significant market design issues, issues of open access to the transmission system, and market power issues in the capacity market as the level of capacity from intermittent and storage resources increases. The failure to apply the must offer requirement consistently could also result in very significant changes in supply from auction to auction which would create price volatility and uncertainty in the capacity market and put PJM's reliability margin at risk. 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.

It is not clear why intermittents and storage were exempted from the must offer obligation to date, and no explicit reason stated, but as the role of intermittents and storage grows it is essential to reestablish the must offer obligation for all resources. The capacity market has included balanced must buy and must sell obligations from its inception.

The MMU concludes that the results of the 2024/2025 RPM Base Residual Auction were competitive. A competitive offer in the capacity market is equal to net ACR.[53] The ACR values were based on data provided by the participants and were consistent with competitive offers for the relevant capacity.

The MMU also concludes that market prices were significantly affected by flaws in the capacity market rules and in the application of the capacity market rules by PJM, including the shape of the VRR curve; the overstatement

52 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>.

53 174 FERC ¶ 61,212 ("March 18th Order") at 65.

of intermittent MW offers; the inclusion of sell offers from DR; and capacity imports.

The MMU also concludes that, although not an issue in the 2024/2025 Base Residual 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.[54] Although the impact did not arise in the 2024/2025 Base Residual Auction, the issue should be addressed immediately in order to prevent the impact from increasing and because the solution is simple.

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 capacity market design be strengthened. The MMU had recommended that generation capacity resources pay penalties if they fail to produce energy when called upon during any of the hours defined as critical. 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.

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

The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[55] [56] [57] [58] [59] [60] [61] [62] [63] [64] [65] In the first three months of 2024, the MMU prepared a number of RPM related reports and testimony, shown in Table 5-2.

The PJM markets have worked to provide incentives to entry and to retain capacity. PJM had excess reserves of 5,979.8 ICAP MW (5,693.8 MW UCAP) on June 1, 2023, and will have excess reserves of 8,899.4 ICAP MW (8,442.2 MW UCAP) on June 1, 2024, based on current positions.[66] A majority of capacity investments in PJM were financed by market sources.[67] Of the 51,857.2 MW of additional capacity that cleared in RPM auctions for the 2007/2008 through 2022/2023 Delivery Years, 39,471.5 MW (76.1 percent) were based on market funding. Of the 4,071.9 MW of additional capacity that cleared in RPM auctions for the 2023/2024 through 2024/2025 Delivery Years, 3,493.7 MW

55 See "Analysis of the 2018/2019 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20182019_RPM_Base_Residual_Auction_20160706.pdf> (July 6, 2016).
56 See "Analysis of the 2019/2020 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20192020_RPM_BRA_20160831-Revised.pdf> (August 31, 2016).
57 See "Analysis of the 2020/2021 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Analysis_of_the_20202021_RPM_BRA_20171117.pdf> (November 11, 2017).
58 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).
59 See "Analysis of the 2022/2023 RPM Base Residual Auction," <https://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20222023_RPM_BRA_20220222.pdf> (February 22, 2022).
60 See "Analysis of the 2023/2024 RPM Base Residual Auction," <https://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf> (October 28, 2022).
61 See the "Analysis of the 2024/2025 RPM Base Residual Auction," <https://www.monitoringanalytics.com/reports/Reports/2023/IMM_Analysis_of_the_20242025_RPM_Base_Residual_Auction_20231030.pdf> (October 30, 2023).
62 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2017," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Report_on_Capacity_Replacement_Activity_4_20171214.pdf> (December 14, 2017).
63 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).
64 See "Analysis of the 2023/2024 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf> (October 28, 2022).
65 See the "Analysis of the 2024/2025 RPM Base Residual Auction," <https://www.monitoringanalytics.com/reports/Reports/2023/IMM_Analysis_of_the_20242025_RPM_Base_Residual_Auction_20231030.pdf> (October 30, 2023).
66 The calculated reserve margin for June 1, 2024, does not account for cleared buy bids that have not been used in replacement capacity transactions.
67 "2020 PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf> (September 15, 2020).

(85.8 percent) were based on market funding. Those investments were made based on the assumption that markets would be allowed to work and that inefficient units would exit.

It is essential that any approach to the PJM markets incorporate a consistent view of how the preferred market design is expected to provide competitive results in a sustainable market design over the long run. A sustainable market design means a market design that results in appropriate incentives to competitive market participants to retire units and to invest in new units over time such that reliability is ensured as a result of the functioning of the market.

A sustainable competitive wholesale power market must recognize three salient structural elements: state nonmarket revenues for renewable energy; a significant level of generation resources subject to cost of service regulation; and the structure and performance of the existing market based generation fleet.

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

Price suppression below the competitive level in the capacity market should not be acceptable and is not consistent with a competitive market design. Harmonizing means that the integrity of each paradigm is maintained and respected. Harmonizing permits nonmarket resources to have an unlimited impact on energy markets and energy prices. Harmonizing means designing a capacity market to account for these energy market impacts, clearly limiting the impact of nonmarket revenues on the capacity market and ensuring competitive outcomes in the capacity market and thus in the entire market.

Table 5-2 RPM related MMU reports: January through March, 2024

Date	Name
January 12, 2024	IMM Answer to PJM Answer re PJM CIFP Docket No. ER24-99 https://www.monitoringanalytics.com/filings/2024/IMM_Answer_to_PJM_Answer_Docket_No_ER24-99_20240112.pdf
January 14, 2024	Data Submission Window Opening for the 2025/2026 RPM Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Opening_-_2025-2026_Base_Residual_Auction_20240114.pdf
January 16, 2024	IMM Answer and Motion for Leave to Answer re PJM MSOC Docket No. ER24-98 https://www.monitoringanalytics.com/filings/2024/IMM_Answer_to_PJM_Answer_Docket_No_ER24-98_20240116.pdf
January 24, 2024	IMM Answer to PJM Def Answer re PJM CIFP Docket No. ER24-99 https://www.monitoringanalytics.com/filings/2024/IMM_Answer_to_PJM_Def_Answer_Docket_No_ER24-99_20240124.pdf
January 25, 2024	IMM Answer and Motion for Leave to Answer re PJM MSOC Docket No. ER24-98 https://www.monitoringanalytics.com/filings/2024/IMM_Answer_to_PJM_Def_Answer_Docket_No_ER24-98_20240125.pdf
February 26, 2024	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2024/2025 and 2025/2026 Delivery Years https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Notice_re_RPM_Must_Offer_Obligations_20240226.pdf
February 29, 2024	IMM Request for Rehearing re PJM CIFP Docket No. ER24-99-000, -001 https://www.monitoringanalytics.com/filings/2024/IMM_Request_for_Rehearing_Docket_No_ER24-99_20240229.pdf
February 29, 2024	Data Submission Window Opening for the 2025/2026 RPM Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Opening_2025-2026_RPM_Base_Residual_Auction_Revised_20240229.pdf

Installed Capacity

On January 1, 2024, RPM installed capacity was 178,375.0 MW (Table 5-3).[68] Over the next three months, new generation, unit deactivations, facility reratings, plus import and export shifts resulted in RPM installed capacity of 178,449.1 MW on March 31, 2024, an increase of 74.1 MW or 0.0 percent from the January 1 level.[69] [70] The 74.1 MW increase was the net result of new or reactivated generation (113.3 MW), decreases in exports (40.6 MW), derates (1,927.4 MW), and net capacity modifications (4.4 MW), partially offset by deactivations or changes in capacity resource status (84.2 MW).

At the beginning of the new delivery year on June 1, 2023, RPM installed capacity was 176,984.4 MW, a decrease of 5,368.0 MW or 2.9 percent from the May 31, 2023, level of 182,352.4 MW. This change occurs as a result of deactivations, derates, capacity modifications, and import/export contracts beginning and/or ending at the start of the new delivery year.

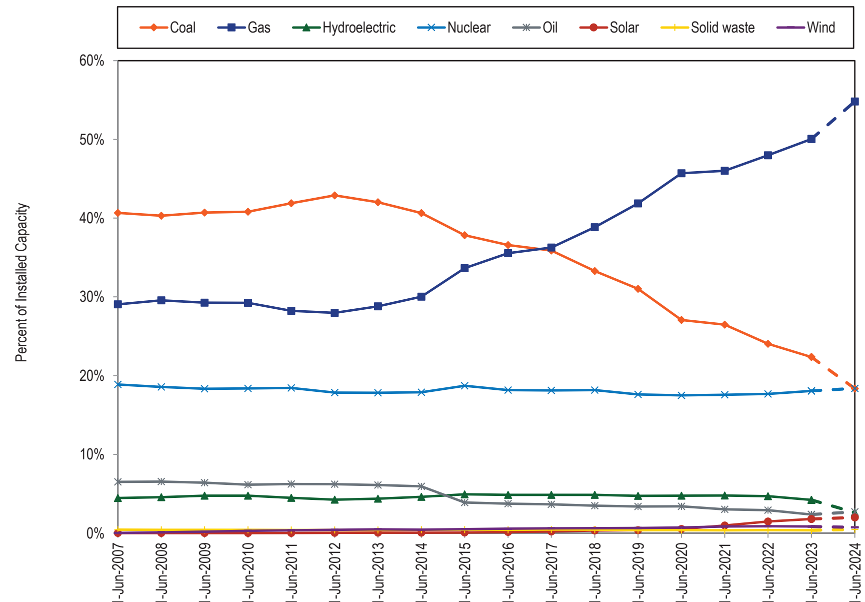
Table 5-3 Installed capacity (By fuel source): January 1, January 31, February 29, and March 31, 2024[71]

	01-Jan-24		31-Jan-24		29-Feb-24		31-Mar-24	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Battery	21.9	0.0%	21.9	0.0%	21.9	0.0%	21.9	0.0%
Coal	37,936.3	21.3%	37,936.3	21.3%	37,911.6	21.3%	37,912.3	21.2%
Gas	88,868.7	49.8%	88,870.5	49.8%	88,826.5	49.8%	88,826.5	49.8%
Hybird	10.2	0.0%	10.2	0.0%	10.2	0.0%	10.2	0.0%
Hydroelectric	7,507.2	4.2%	7,507.2	4.2%	7,507.2	4.2%	7,507.2	4.2%
Nuclear	32,183.0	18.0%	32,183.0	18.0%	32,180.5	18.0%	32,180.5	18.0%
Oil	4,295.6	2.4%	4,295.6	2.4%	4,285.2	2.4%	4,285.2	2.4%
Solar	3,603.3	2.0%	3,648.1	2.0%	3,672.8	2.1%	3,716.6	2.1%
Solid waste	627.4	0.4%	627.4	0.4%	627.4	0.4%	627.4	0.4%
Wind	3,321.4	1.9%	3,321.4	1.9%	3,321.4	1.9%	3,361.3	1.9%
Total	178,375.0	100.0%	178,421.6	100.0%	178,364.7	100.0%	178,449.1	100.0%

68 Percent values shown in Table 5-3 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.
69 Unless otherwise specified, the capacity described in this section is the summer installed capacity rating of all PJM generation capacity resources, as entered into the Capacity Exchange system, regardless of whether the capacity cleared in the RPM auctions.
70 Wind resources accounted for 3,321.4 MW, and solar resources accounted for 3,513.3 MW of installed capacity in PJM on December 31, 2023. Prior to the 2023/2024 Delivery Year, PJM administratively reduced the capabilities of all wind generators to 14.7 percent for wind farms in mountainous terrain and 17.6 percent for wind farms in open terrain, and solar generators to 42.0 percent for ground mounted fixed panel, 60.0 percent for ground mounted tracking panel, and 38.0 percent for other than ground mounted solar arrays, of nameplate capacity when determining the installed capacity because wind and solar resources cannot be assumed to be available on peak and cannot respond to dispatch requests. As data became available, unforced capability of wind and solar resources was be calculated using actual data. There are additional wind and solar resources not reflected in total capacity because they are energy only resources and do not participate in the PJM Capacity Market. See "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," Appendix B.3 Calculation Procedure, Rev. 18 (July 26, 2023). The derating approach has been replaced with ELCC starting in the 2023/2024 Delivery Year.
71 The data for hybrid solar/battery resources are included in the solar data for confidentiality reasons.

Figure 5-1 shows the share of installed capacity by fuel source for the first day of each delivery year, from June 1, 2007, to June 1, 2023, as well as the expected installed capacity for the 2024/2025 Delivery Year, based on the results of all auctions held through March 31, 2024.[72] On June 1, 2007, coal comprised 40.7 percent of the installed capacity, reached a maximum of 42.9 percent in 2012, decreased to 22.4 percent on June 1, 2023, and is projected to decrease to 18.4 percent by June 1, 2024. The share of gas increased from 29.1 percent on June 1, 2007, to 50.1 percent on June 1, 2023, and is expected to increase to 54.8 percent on June 1, 2024.

Figure 5-1 Percent of installed capacity (By fuel source): June 1, 2007 through June 1, 2024



72 Due to EFORd values not being finalized for future delivery years, the projected installed capacity is based on cleared unforced capacity (UCAP) MW using the EFORd submitted with the offer.

Table 5-4 shows the RPM installed capacity on January 1, 2024, through March 31, 2024, for the top five generation capacity resource owners, excluding FRR committed MW.

Table 5-4 Installed capacity by parent company: January 1, January 31, February 29, and March 31, 2024

	01-Jan-24			31-Jan-24			29-Feb-24			31-Mar-24		
Parent Company	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank
Constellation Energy Generation, LLC	20,288.1	13.9%	1	20,288.1	13.9%	1	20,285.6	13.9%	1	20,285.6	13.9%	1
ArcLight Capital Partners, LLC	12,115.2	8.3%	2	12,155.0	8.3%	2	12,153.0	8.3%	2	10,792.1	7.4%	3
LS Power Group	11,486.7	7.9%	3	11,486.7	7.9%	3	11,485.7	7.9%	3	11,485.7	7.9%	2
Teachers Insurance and Annuity Association of America	10,167.9	7.0%	4	10,167.9	7.0%	4	10,167.9	7.0%	4	10,167.9	7.0%	4
Vistra Energy Corp.	8,669.4	6.0%	5	8,669.4	6.0%	5	8,689.0	6.0%	5	8,289.3	5.7%	5

The sources of funding for generation owners can be categorized as one of two types: market and nonmarket. Market funding is from private investors bearing the investment risk without guarantees or support from any public sources, subsidies or guaranteed payment by ratepayers. Providers of market funding rely entirely on market revenues. Nonmarket funding is from guaranteed revenues, including cost of service rates for a regulated utility and subsidies. Table 5-5 shows the RPM installed capacity on January 1, 2024, to March 31, 2024, by funding type.

Table 5-5 Installed capacity by funding type: January 1, January 31, February 29, and March 31, 2024

	01-Jan-24		31-Jan-24		29-Feb-24		31-Mar-24	
Funding Type	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP
Market	131,927.9	74.0%	131,929.7	73.9%	131,876.5	73.9%	131,921.0	73.9%
Nonmarket	46,447.1	26.0%	46,491.9	26.1%	46,488.2	26.1%	46,528.1	26.1%
Total	178,375.0	100.0%	178,421.6	100.0%	178,364.7	100.0%	178,449.1	100.0%

Fuel Diversity

Figure 5-2 shows the fuel diversity index (FDI_c) for RPM installed capacity.[73] The FDI_c is defined as $1-\sum_{i=1}^{N} s_i^2$, where s_i is the percent share of fuel type i. The minimum possible value for the FDI_c is zero, corresponding to all capacity from a single fuel type. The maximum possible value for the FDI_c is achieved when each fuel type has an equal share of capacity. For a capacity mix of eight fuel types, the maximum achievable index is 0.875. For all FDI calculations prior to June 1, 2023, the fuel type categories used in the calculation of the FDI_c are the eight fuel sources in Table 5-3. Two additional resource types are included beginning in June 2023. Batteries were added to the resource mix on June 1, 2023, and hybrid solar resources were added on January 1, 2024. The maximum achievable index with nine fuel types is 0.889. The maximum achievable index with ten fuel types is 0.900. The FDI_c is stable and does not exhibit any long-term trends. The only significant deviation occurred with the expansion of the PJM footprint. On April 1, 2002, PJM expanded with the addition of Allegheny Power System, which added about 12,000 MW of generation.[74] The reduction in the FDI_c resulted from an increase in coal capacity resources. A similar but

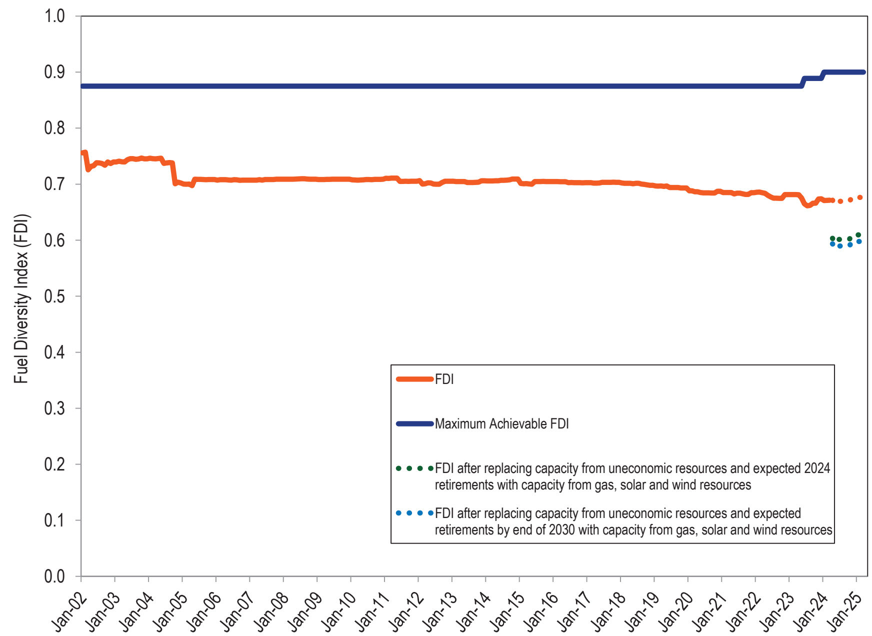
73 The MMU developed the FDI to provide an objective metric of fuel diversity. The FDI metric is similar to the HHI used to measure market concentration. The FDI is calculated separately for energy output and for installed capacity. The FDI_c includes derated capacity values for intermittent capacity subject to derating.

74 On April 1, 2002, the PJM Region expanded with the addition of Allegheny Power System under a set of agreements known as "PJM-West." See page 4 in the *2002 Annual State of the Market Report for PJM* for additional details.

more significant reduction occurred in 2004 with the expansion into the COMED, AEP, and DAY Control Zones.[75] The average FDI_c for the first three months of 2024 decreased 1.5 percent compared to the first three months of 2023. Figure 5-2 also includes the expected FDI_c through March 2025 based on cleared RPM auctions. The expected FDI_c is indicated in Figure 5-2 by the dotted orange line.

The FDI_c was used to measure the impact on fuel diversity of potential retirements of resources that the MMU has identified as being at risk of retirement. A total of 57,694 MW of capacity are at risk of retirement, consisting of 4,285 MW currently planning to retire, 19,635 MW expected to retire for regulatory reasons and 33,744 MW expected to be uneconomic.[76] The dotted green line in Figure 5-2 shows the FDI_c assuming that the capacity from the expected 2024 retirements were replaced by gas, wind and solar capacity.[77] The FDI_c under these assumptions would have been 10.1 percent lower than the actual FDI_c. The dotted blue line in Figure 5-2 shows the FDI_c assuming that the capacity from the expected retirements through 2030 were replaced by gas, wind and solar capacity.[78] The counterfactual FDI_c in this scenario is 11.8 percent lower than the actual FDI_c.

Figure 5-2 Fuel Diversity Index for installed capacity: January 1, 2002 through March 1, 2025



75 See the *2019 Annual State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for an explanation of the expansion of the PJM footprint. The integration of the COMED Control Area occurred in May 2004 and the integration of the AEP and DAY Control Zones occurred in October 2004.

76 See the *2023 Annual State of the Market Report for PJM*, Volume II, Section 7: Net Revenue.

77 It is assumed that 3,009.0 MW of replacement capacity is from solar units and 285.9 MW from wind units, with the remaining replacement capacity coming from gas units. This is the amount of derated wind and solar capacity needed to produce 3,442.7 GWh of generation in the first three months of 2024 assuming the average capacity derate factors in the Planned Generation Additions subsection of Section 12 and the average capacity factors for wind and solar capacity resources in Table 8-33 and Table 8-36. This level of GWh represents the increase in renewable generation required by RPS in 2025 over the level of renewable generation that was required by RPS in the first three months of 2024. The split between solar and wind is based on queue data.

78 It is assumed that 12,313.8 MW of replacement capacity is from solar units and 1,169.9 MW from wind units, with the remaining replacement capacity coming from gas units. This is the amount of derated wind and solar capacity needed to produce 14,088.8 GWh of generation in 2030 assuming the average capacity derate factors in the Planned Generation Additions subsection of Section 12 and the average capacity factors for wind and solar capacity resources in Table 8-33 and Table 8-36. This level of GWh represents the increase in renewable generation required by RPS in 2030 over the level of renewable generation that was required by RPS in the first three months of 2024. The split between solar and wind is based on queue data.

RPM Capacity Market

The RPM Capacity Market, implemented June 1, 2007, is a forward looking, annual, locational market, with a must offer requirement for existing generation capacity resources, except for intermittent and storage resources including hydro, and except for resources owned by entities that elect the fixed resource requirement (FRR) option, and mandatory participation by load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand side resources.

Annual base auctions are held in May for delivery years that are three years in the future. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[79] In the first three months of 2024, the 2024/2025 RPM Third Incremental Auction was conducted. The 2024/2025 RPM Base Residual Auction was conducted in 2022, but the results were not posted until February 27, 2023, due to an issue with the DPL South reliability requirement. The Commission orders addressing the issue with the DPL South reliability requirement were reversed on appeal.[80] Commission action on the matter is pending. As a result, final prices for the 2024/2025 have not been approved. The 2025/2026 RPM Base Residual Auction was scheduled for June 2023 but postponed until June 2024 and then postponed again until July 2024.[81]

Market Structure

Supply

Table 5-6 shows generation capacity changes since the implementation of the Reliability Pricing Model through the 2022/2023 Delivery Year. The 17,459.0 MW increase was the result of new generation capacity resources (42,070.0 MW), reactivated generation capacity resources (1,380.4 MW), uprates (8,406.8 MW), integration of external zones (21,967.5 MW), a net decrease in capacity exports (1,818.7 MW), offset by a net decrease in capacity imports (1,482.3 MW), deactivations (52,630.1 MW) and derates (4,072.0 MW).

Table 5-7 shows the calculated RPM reserve margin and reserve in excess of the defined installed reserve margin (IRM) for June 1, 2019, through June 1, 2024, and accounts for cleared capacity, replacement capacity, and deficiency MW for all auctions held and the most recent peak load forecast for each delivery year. The completion of the replacement process using cleared buy bids from RPM incremental auctions includes two transactions. The first step is for the entity to submit and clear a buy bid in an RPM incremental auction. The next step is for the entity to complete a separate replacement transaction using the cleared buy bid capacity. Without an approved early replacement transaction requested for defined physical reasons, replacement capacity transactions can be completed only after the EFORds for the delivery year are finalized, on November 30 in the year prior to the delivery year, but before the start of the delivery day. The calculated reserve margin for June 1, 2024, does not account for cleared buy bids that have not been used in replacement capacity transactions.

Future Changes in Generation Capacity[82]

As shown in Table 5-6, for the period from the introduction of the RPM capacity market design in the 2007/2008 Delivery Year through the 2022/2023 Delivery Year, internal installed capacity decreased by 4,844.9 MW after accounting for new capacity resources, reactivations, and uprates (51,857.2 MW) and capacity deactivations and derates (56,702.1 MW).

For the current and future delivery years (2023/2024 through 2024/2025), new generation capacity is defined as capacity that cleared an RPM auction for the first time for the specified delivery year. Based on expected completion rates of cleared new generation capacity (3,727.4 MW) and pending deactivations (1,508.7 MW), PJM capacity is expected to increase by 1,763.7 MW for the 2023/2024 through 2024/2025 Delivery Years.

79 See Letter Order, Docket No. ER10-366-000 (January 22, 2010).
80 See PJM Power Providers Grp. v. FERC, 96 F.4th 390 (3d Cir. 2024).
81 See 183 FERC ¶ 61,172 (2023) and 186 FERC ¶ 61,144 (2024).

82 For more details on future changes in generation capacity, see "2020 PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf> (September 15, 2020).

Table 5-6 Generation capacity changes: 2007/2008 through 2022/2023[83]

	ICAP (MW)								
	New	Reactivations	Uprates	Integration	Net Change in Capacity Imports	Net Change in Capacity Exports	Deactivations	Derates	Net Change
2007/2008	45.0	0.0	691.5	0.0	70.0	15.3	380.0	417.0	(5.8)
2008/2009	815.4	238.3	987.0	0.0	473.0	(9.9)	609.5	421.0	1,493.1
2009/2010	406.5	0.0	789.0	0.0	229.0	(1,402.2)	108.4	464.3	2,254.0
2010/2011	153.4	13.0	339.6	0.0	137.0	367.7	840.6	223.5	(788.8)
2011/2012	3,096.4	354.5	507.9	16,889.5	(1,183.3)	(1,690.3)	2,542.0	176.2	18,637.1
2012/2013	1,784.6	34.0	528.1	47.0	342.4	84.0	5,536.0	317.8	(3,201.7)
2013/2014	198.4	58.0	372.8	2,746.0	934.3	28.9	2,786.9	288.3	1,205.4
2014/2015	2,276.8	20.7	530.2	0.0	2,335.7	177.3	4,915.6	360.3	(289.8)
2015/2016	4,291.8	90.0	449.0	0.0	511.4	(117.8)	8,338.2	215.8	(3,094.0)
2016/2017	3,679.3	532.0	419.2	0.0	575.6	722.9	659.4	206.7	3,617.1
2017/2018	4,127.3	5.0	562.1	0.0	(1,025.1)	(695.1)	2,657.4	148.5	1,558.5
2018/2019	8,127.5	4.0	330.9	2,120.0	(3,217.0)	212.7	6,730.0	89.2	333.5
2019/2020	4,612.0	13.3	494.9	165.0	(1,196.6)	401.3	3,296.0	116.8	274.5
2020/2021	403.1	11.6	575.4	0.0	(37.9)	(111.6)	3,572.0	206.4	(2,714.6)
2021/2022	3,309.3	6.0	412.2	0.0	38.5	1,066.1	2,197.6	125.5	376.8
2022/2023	4,743.2	0.0	417.0	0.0	(469.3)	(868.0)	7,460.5	294.7	(2,196.3)
Total	42,070.0	1,380.4	8,406.8	21,967.5	(1,482.3)	(1,818.7)	52,630.1	4,072.0	17,459.0

As shown in Table 5-7, based on current positions, total reserves on June 1, 2024, will be 28,754.0 MW, of which 8,442.2 MW (UCAP) are in excess of the required level of reserves, which is 20,311.8 MW (UCAP).[84] In the 2024/2025 BRA, 18,133.0 MW were considered categorically exempt from the must offer requirement based on intermittent and capacity storage classification. Some of these resources were offered as capacity in the BRA and as part of FRR plans. The result was that 5,772.3 MW of intermittent and storage resources (31.8 percent of the categorically exempt MW and 3.9 percent of total cleared MW) were not offered in the 2024/2025 BRA.

In the 2024/2025 BRA, the sum of cleared MW that were considered categorically exempt from the must offer requirement is 8,319.3 MW, or 49.3 percent of the required reserves and 33.3 percent of total reserves. The cleared MW of DR is 8,083.9 MW, or 47.9 percent of required reserves and 32.4 percent of total reserves. The sum of cleared MW that were categorically exempt from the must offer requirement and the cleared MW of DR is 16,403.2 MW, or 97.2 percent of required reserves and 65.7 percent of total reserves.

These results suggest that the required reserve margin and the actual reserve margin be considered carefully along with the obligations of the resources that the reserve margin assumes will be available.

83 The capacity changes in this report are calculated based on June 1 through May 31.
84 The calculated reserve margin for June 1, 2024, does not account for cleared buy bids that have not been used in replacement capacity transactions.

Table 5-7 RPM reserve margin: June 1, 2019, to June 1, 2024[85][86]

	01-Jun-19	01-Jun-20	01-Jun-21	01-Jun-22	01-Jun-23	01-Jun-24	
Forecast peak load ICAP (MW)	151,643.5	148,355.3	149,482.9	149,263.6	149,382.2	151,639.1	A
FRR peak load ICAP (MW)	12,284.2	11,488.3	11,717.7	28,292.8	29,554.6	30,431.0	B
PRD ICAP (MW)	0.0	558.0	510.0	230.0	235.0	305.0	C
Installed reserve margin (IRM)	16.0%	15.5%	14.7%	14.9%	14.9%	17.7%	D
Pool wide average EFORd	6.08%	5.78%	5.22%	5.08%	4.87%	5.10%	E
Forecast pool requirement (FPR)	1.090	1.088	1.087	1.091	1.093	1.117	F=(1+D)*(1-E)
RPM committed less deficiency UCAP (MW) (generation and DR)	162,276.1	159,560.4	156,633.6	137,944.8	136,408.5	143,491.0	G
RPM committed less deficiency ICAP (MW) (generation and DR)	172,781.2	169,348.8	165,260.2	145,327.4	143,391.7	151,202.3	H=G/(1-E)
RPM peak load ICAP (MW)	139,359.3	136,309.0	137,255.2	120,740.8	119,592.6	120,903.1	J=A-B-C
Reserve margin ICAP (MW)	33,421.9	33,039.8	28,005.0	24,586.6	23,799.1	30,299.2	K=H-J
Reserve margin (%)	24.0%	24.2%	20.4%	20.4%	19.9%	25.1%	L=K/J
Reserve margin in excess of IRM ICAP (MW)	11,124.4	11,911.9	7,828.5	6,596.3	5,979.8	8,899.4	M=K-D*J
Reserve margin in excess of IRM (%)	8.0%	8.7%	5.7%	5.5%	5.0%	7.4%	N=M/J
RPM peak load UCAP (MW)	130,886.3	128,430.3	130,090.5	114,607.2	113,768.4	114,737.0	P=J*(1-E)
RPM reliability requirement UCAP (MW)	151,832.0	148,331.5	149,210.1	131,679.9	130,714.7	135,048.8	Q=J*F
Reserve margin UCAP (MW)	31,389.8	31,130.1	26,543.1	23,337.6	22,640.1	28,754.0	R=G-P
Reserve cleared in excess of IRM UCAP (MW)	10,444.1	11,228.9	7,423.5	6,264.9	5,693.8	8,442.2	S=G-Q
Projected replacement capacity UCAP (MW)	0.0	0.0	0.0	0.0	0.0	1,031.3	T
Projected reserve margin	24.0%	24.2%	20.4%	20.4%	19.9%	24.2%	U=(H-T/(1-E))/J-1

Sources of Funding[87]

Developers use a variety of sources to fund their projects, including Power Purchase Agreements (PPA), cost of service rates, and private funds (from internal sources or private lenders and investors). PPAs can be used for a variety of purposes and the use of a PPA does not imply a specific source of funding.

New and reactivated generation capacity from the 2007/2008 Delivery Year through the 2022/2023 Delivery Year totaled 43,450.4 MW (83.8 percent of all additions), with 33,507.2 MW from market funding and 9,043.2 MW from nonmarket funding. Uprates to existing generation capacity from the 2007/2008 Delivery Year through the 2022/2023 Delivery Year totaled 8,406.8 MW (16.2 percent of all additions), with 5,964.3 MW from market funding and 2,442.5 MW from nonmarket funding. In summary, of the 51,857.2 MW of additional capacity from new, reactivated, and uprated generation that cleared in RPM auctions for the 2007/2008 through 2022/2023 Delivery Years, 39,471.5 MW (76.1 percent) were based on market funding.

Of the 4,071.9 MW of the additional generation capacity (new resources, reactivated resources, and uprates) that cleared in RPM auctions for the 2023/2024 Delivery Year through the 2024/2025 Deliver Year, 2,281.9 MW are not yet in service.[88] Of those 2,281.9 MW that have not yet gone into service, 1,949.3 MW have market funding and 332.6 MW have nonmarket funding. Applying the historical completion rates, 65.0 percent of all the projects in development are expected to go into service (1,262.5 MW of the 1,949.3 MW of in development market funded projects; 219.8 MW of the 332.6 MW of in development nonmarket

85 The calculated reserve margins in this table do not include EE on the supply side or the EE addback on the demand side. The EE excluded from the supply side for this calculation includes annual EE and summer EE. This is how PJM calculates the reserve margin.
86 These reserve margin calculations do not consider Fixed Resource Requirement (FRR) load.
87 For more details on sources of funding for generation capacity, see "2020 PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf> (September 15, 2020).
88 Of the MW that cleared in RPM auctions for the 2023/2024 Delivery Year through the 2024/2025 Delivery Year, 10.5 MW have since been withdrawn from the PJM project queue.

funded projects). Together, 1,482.4 MW of the 2,281.9 MW of generation capacity that cleared MW in RPM and are not yet in service are expected to go into service in the 2023/2024 through 2024/2025 Delivery Years.[89]

Of the 1,790.0 MW of the additional generation capacity that cleared in RPM auctions for the 2023/2024 through 2024/2025 Delivery Years and are already in service, 1,544.4 MW (86.3 percent) are based on market funding and 245.6 MW (13.7 percent) are based on nonmarket funding.

In summary, 3,493.7 MW (85.8 percent) of the additional generation capacity (1,949.3 MW not yet in service and 1,544.4 MW in service) that cleared in RPM auctions for the 2023/2024 through 2024/2025 Delivery Years are based on market funding. Capacity additions based on nonmarket funding are 578.2 MW (14.2 percent) of proposed generation that cleared the RPM auctions for the 2023/2024 through 2024/2025 Delivery Years.

Demand

The MMU analyzed market sectors in the PJM Capacity Market to determine how they met their load obligations. The PJM Capacity Market was divided into the following sectors:

- **PJM EDC.** EDCs with a franchise service territory within the PJM footprint. This sector includes traditional utilities, electric cooperatives, municipalities and power agencies.
- **PJM EDC Generating Affiliate.** Affiliate companies of PJM EDCs that own generating resources.
- **PJM EDC Marketing Affiliate.** Affiliate companies of PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-PJM EDC.** EDCs with franchise service territories outside the PJM footprint.
- **Non-PJM EDC Generating Affiliate.** Affiliate companies of non-PJM EDCs that own generating resources.
- **Non-PJM EDC Marketing Affiliate.** Affiliate companies of non-PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-EDC Generating Affiliate.** Affiliate companies of non-EDCs that own generating resources.
- **Non-EDC Marketing Affiliate.** Affiliate companies of non-EDCs that sell power and have load obligations in PJM, but do not own generating resources.

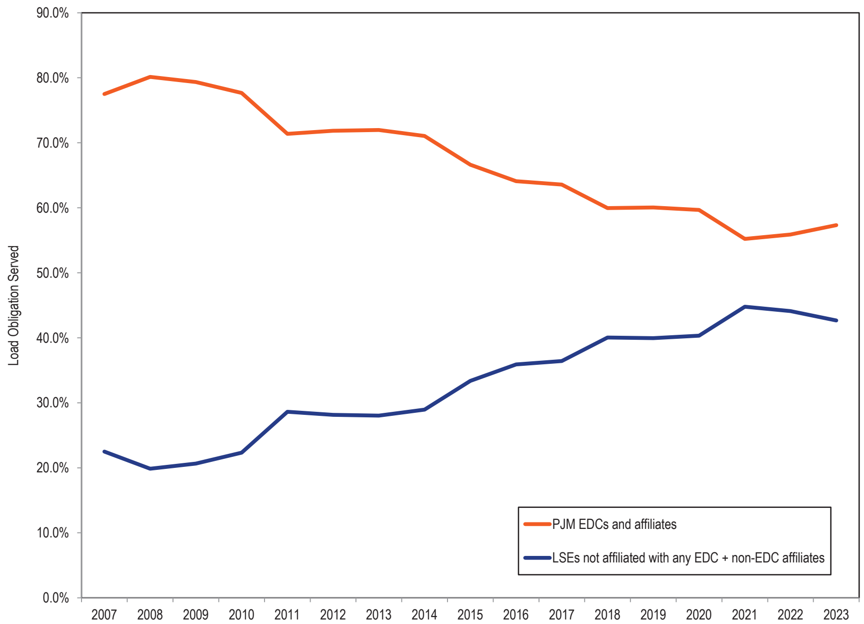
On June 1, 2023, PJM EDCs and their affiliates maintained a majority market share of load obligations under RPM, together totaling 57.3 percent (Table 5-8), up from 55.9 percent on June 1, 2022. The combined market share of LSEs not affiliated with any EDC and of non-PJM EDC affiliates was 42.7 percent, down from 44.1 percent on June 1, 2022. The share of capacity market load obligation fulfilled by PJM EDCs and their affiliates, and LSEs not affiliated with any EDC and non-PJM EDC affiliates from June 1, 2007, to June 1, 2023, is shown in Figure 5-3. PJM EDCs' and their affiliates' share of load obligation has decreased from 77.5 percent on June 1, 2007, to 57.3 percent on June 1, 2023. The share of load obligation held by LSEs not affiliated with any EDC and non-PJM EDC affiliates increased from 22.5 percent on June 1, 2007, to 42.7 percent on June 1, 2023. Prior to the 2012/2013 Delivery Year, obligation was defined as cleared and make whole MW in the Base Residual Auction and the Second Incremental Auction plus ILR forecast obligations. Effective with the 2012/2013 Delivery Year, obligation is defined as the sum of the unforced capacity obligations satisfied through all RPM auctions for the delivery year.

89 See the *2023 Annual State of the Market Report for PJM*, Volume II, Section 12: Generation and Transmission Planning.

Table 5-8 Capacity market load obligation served: June 1, 2022 and June 1, 2023

	01-Jun-22		01-Jun-23		Change	
	Obligation (MW)	Percent of total obligation	Obligation (MW)	Percent of total obligation	Obligation (MW)	Percent of total obligation
PJM EDCs and Affiliates	100,803.7	55.9%	101,469.1	57.3%	665.4	1.4%
LSEs not affiliated with any EDC + non EDC Affiliates	79,537.6	44.1%	75,548.7	42.7%	(3,989.0)	(1.4%)
Total	180,341.3	100.0%	177,017.7	100.0%	(3,323.6)	0.0%

Figure 5-3 Capacity market load obligation served: June 1, 2007 through June 1, 2023



Capacity Transfer Rights (CTRs)

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

The total required capacity in an LDA is provided by a mix of internal capacity and imported capacity. The imported capacity equals the total required capacity minus the internal capacity. The value of CTRs is based on the fact that load in an LDA pays the clearing price for all cleared capacity but that generators who provide imported capacity are paid a lower price based on the LDA in which they are located. The value of CTRs equals the imported MW times the price difference. This excess is paid by load and is returned to load using CTRs. CTRs are intended to permit customers to receive the benefit of importing cheaper capacity using transmission capability.

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

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

The CTR issue implies a broader issue with capacity market clearing and settlements. The capacity market is cleared based on a three year ahead forecast of load and offers of capacity. Payments to capacity resources in the delivery year are based on the capacity market clearing prices and quantities. But payments by customers in the delivery year are not based on market clearing prices and quantities. Payments by customers in each zone are based on the ratio of zonal forecast peak load to the RTO forecast peak load used for the Third Incremental Auction, run six months prior to the delivery year when auctions follow the traditional schedule.[90] The allocation sometimes creates significant differences between the capacity cleared to meet the reliability requirement and the capacity obligation allocated to the customers in a zone. For example, ComEd Zone, which is identical to ComEd LDA, cleared 27,932.1 MW including 5,574.0 MW of imports in the 2021/2022 RPM BRA. The ComEd Zone's capacity obligation, immediately after the clearing of the Base Residual Auction was 24,983.0 MW. The final ComEd Zone's capacity obligation for the 2021/2022 Delivery Year after the Third Incremental Auction was 22,721.2 MW.

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

For LDAs in which the RPM auctions for a delivery year resulted in a positive average weighted Locational Price Adder, an LSE with CTRs corresponding to the LDA is entitled to a payment or charge equal to the Locational Price Adder multiplied by the MW of the LSEs' CTRs. The definition of the MW does not reflect auction clearing MW.

In the 2024/2025 RPM Base Residual Auction, BGE had 4,513.2 MW of CTRs with a total value of $38,728,614 and DPL had 544.7 MW of CTRs with a total value of $120,535. EMAAC, excluding DPL, had 3,704.1 MW of CTRs with a total value of $7,381,909 and DEOK had 3,015.4 MW of CTRs with a total value of $74,093,944.

MAAC had 1,026.2 MW of customer funded ICTRs with a total value of $7,704,472, EMAAC had 40.0 MW of customer funded ICTRs with a total value of $79,716, BGE had 65.7 MW of customer funded ICTRs with a total value of $563,782 and DEOK had 155.0 MW of customer funded ICTRs with a total value of $3,808,629.

MAAC had 486.4 MW of ICTRs due to Incremental Rights-Eligible Required Transmission Enhancements with a value of $3,651,831, EMAAC had 948.0 MW of ICTRs due to Incremental Rights-Eligible Required Transmission Enhancements with a value of $1,889,269 and BGE had 306.0 MW with a value of $2,625,832.

Demand Curve

A central feature of PJM's Reliability Pricing Model (RPM) design is that the demand curve, or Variable Resource Requirement (VRR) curve, has a downward sloping segment. In the RPM market design, the supply of three year forward capacity is cleared against this VRR curve. A VRR curve is defined for each Locational Deliverability Area (LDA). This shape replaced the vertical demand curve at the reliability requirement. The downward sloping segment begins at the MW level that is approximately 1.0 percent less than the reliability requirement.[91] Figure 5-4 shows the shape of the VRR curve compared to a vertical demand curve at the reliability requirement for the 2024/2025 RPM Base Residual Auction.

In proposing the downward sloping portion of the VRR curve, PJM asserted that the sloping VRR curve recognizes the value of incremental capacity

90 See "PJM Manual 18: PJM Capacity Market," § 7.2.3 Final Zonal Unforced Capacity Obligations, Rev. 58 (Nov. 15, 2023).

91 The formula for the MW level where the VRR curve begins the downward slope is given by *(Reliability Requirement) x [1 – 1.2% / (Installed Reserve Margin)].*

above the target reserve margin providing additional reliability benefit at a declining rate.[92]

The initial VRR curve, introduced in 2007, had a maximum price equal to 1.5 times the Net Cost of New Entry (Net CONE), determined annually based on fixed cost of new generating capacity or Gross Cost of New Entry (Gross CONE), net of the three year average energy and ancillary service revenues. That VRR curve was structured to yield auction clearing prices equal to the 1.5 times Net CONE when the amount of capacity cleared was less than 99 percent of the target reserve margin and below 1.5 times Net CONE when the amount of capacity cleared was greater than 99 percent of the target reserve margin.

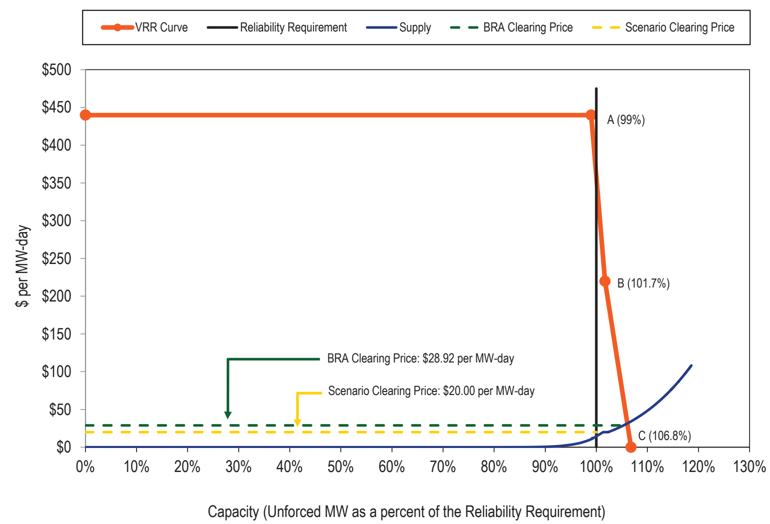
Effective for the 2018/2019 and subsequent delivery years, PJM revised the VRR curve.[93] PJM defines the reliability requirement as the capacity needed to satisfy the one event in ten years loss of load expectation (LOLE) for the RTO and capacity needed to satisfy the one event in 25 years loss of load expectation for the each LDA. The maximum price on the VRR curve is the greater of Gross CONE or 1.5 times Net CONE for all unforced capacity MW between 0 and 99 percent of the reliability requirement. The first downward sloping segment is from 99 percent and 101.7 percent of the reliability requirement. The second downward sloping segment is from 101.7 percent and 106.8 percent of the reliability requirement (Figure 5-4).

The downward sloping shape of the demand curve, the VRR curve, had a significant impact on the outcome of the 2024/2025 BRA. As a result of the downward sloping VRR demand curve, more capacity cleared in the market than would have cleared with a vertical demand curve set equal to the reliability requirement.

Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2024/2025 RPM Base Residual Auction were $2,198,835,999. If PJM had used a vertical demand curve set equal to the reliability requirement for 2024/2025 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2024/2025 RPM Base Residual Auction would have been $1,381,442,645, a decrease of $817,393,354, or 37.2 percent, compared to the actual results. From another perspective, clearing the auction using a downward sloping VRR curve resulted in a 59.2 percent increase in RPM revenues for the 2024/2025 RPM Base Residual Auction compared to what RPM revenues would have been with a vertical demand curve set equal to the reliability requirement.

The PJM definition of the VRR curve means the clearing price and cleared quantity will be higher, almost without exception, using the current VRR curve than using a vertical demand curve at the reliability requirement. As a result, payments for capacity will be higher. Figure 5-4 shows the RTO VRR curve and RTO reliability requirement for the 2024/2025 RPM BRA. The clearing price and cleared quantity would have been lower if a vertical VRR curve set at the reliability requirement had been used in place of the existing VRR curve. In the 2024/2025 BRA, the RTO clearing price would have decreased from $28.92 per MW-day to $20.00 per MW-day, and the clearing quantity would have decreased from 147,478.9 MW to 139,121.6 MW.

Figure 5-4 Shape of the VRR curve relative to the reliability requirement: 2024/2025 Delivery Year



92 See 117 FERC ¶ 61,331 (2006).
93 "Third Triennial Review of PJM's Variable Resource Requirement Curve," The Brattle Group, May 15, 2014, <http://www.pjm.com//media/library/reports-notices/reliability-pricing-model/20140515-brattle-2014-pjm-vrr-curvereport.ashx?la=en>.

Market Concentration

Auction Market Structure

As shown in Table 5-9, in the 2024/2025 RPM Third Incremental Auction all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[94] Offer caps were applied to all sell offers for resources which were subject to mitigation when the capacity market seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[95] [96] [97]

In applying the market structure test, the relevant supply for the RTO market includes all supply offered at less than or equal to 150 percent of the RTO cost-based clearing price. The relevant supply for the constrained LDA markets includes the incremental supply inside the constrained LDAs which was offered at a price higher than the unconstrained clearing price for the parent LDA market and less than or equal to 150 percent of the cost-based clearing price for the constrained LDA. The relevant demand consists of the MW needed inside the LDA to relieve the constraint.

Table 5-9 presents the results of the TPS test. A generation owner or owners are pivotal if the capacity of the owners' generation facilities is needed to meet the demand for capacity. The results of the TPS are measured by the residual supply index (RSI_x). The RSI_x is a general measure that can be used with any number of pivotal suppliers. The subscript denotes the number of pivotal suppliers included in the test. If the RSI_x is less than or equal to 1.0, the supply owned by the specific generation owner, or owners, is needed to meet market demand and the generation owners are pivotal suppliers with a significant ability to influence market prices. If the RSI_x is greater than 1.0, the supply of the specific generation owner or owners is not needed to meet market demand and those generation owners have a reduced ability to unilaterally influence market price.

94 The market definition used for the TPS test includes all offers with costs less than or equal to 1.50 times the clearing price. See *MMU Technical Reference for PJM Markets*, at "Three Pivotal Supplier Test" for additional discussion.
95 See OATT Attachment DD § 6.5.
96 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 at P 30 (2009).
97 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for planned generation capacity resource and creating a new definition for existing generation capacity resource for purposes of the must offer requirement and market power mitigation, and treating a proposed increase in the capability of a generation capacity resource the same in terms of mitigation as a planned generation capacity resource. See 134 FERC ¶ 61,065 (2011).

Table 5-9 RSI results: 2021/2022 through 2024/2025 RPM Auctions[98]

RPM Markets	$RSI_{1,\,1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
2021/2022 Base Residual Auction				
RTO	0.80	0.68	122	122
EMAAC	0.71	0.22	14	14
PSEG	0.20	0.01	5	5
ATSI	0.01	0.00	2	2
ComEd	0.08	0.02	5	5
BGE	0.23	0.00	3	3
2021/2022 First Incremental Auction				
RTO	0.57	0.48	26	26
EMAAC	0.00	0.82	5	3
PSEG	0.00	0.00	1	1
PSEG North	0.00	0.00	2	2
BGE	0.00	0.00	1	1
2021/2022 Second Incremental Auction				
RTO	0.19	0.12	19	19
EMAAC	0.05	0.23	7	5
PSEG	0.00	0.00	2	2
BGE	0.00	0.00	0	0
2021/2022 Third Incremental Auction				
RTO	0.57	0.41	59	59
EMAAC	1.00	0.19	6	6
PSEG	0.00	0.00	1	1
BGE	0.00	-0.00	2	2
2022/2023 Base Residual Auction				
RTO	0.81	0.73	130	130
MAAC	0.69	0.37	25	25
EMAAC	1.25	0.64	7	7
ComEd	0.43	0.36	14	14
BGE	0.00	0.00	1	1
DEOK	0.00	0.00	1	1
2022/2023 Third Incremental Auction				
RTO	0.68	0.50	43	43
MAAC	0.40	0.05	9	9
2023/2024 Base Residual Auction				
RTO	0.78	0.68	134	134
MAAC	0.78	0.40	11	11
DPL South	0.00	0.00	1	1
BGE	0.00	0.00	1	1
2023/2024 Third Incremental Auction				
RTO	0.77	0.76	51	15
MAAC	0.41	0.76	17	9
EMAAC	0.45	0.18	10	10
BGE	0.00	0.00	1	1
2024/2025 Base Residual Auction				
RTO	0.77	0.64	133	133
MAAC	0.59	0.11	9	9
EMAAC	0.48	0.00	2	2
DPL South	0.00	0.00	1	1
BGE	0.00	0.00	1	1
DEOK	0.00	0.00	1	1
2024/2025 Third Incremental Auction				
RTO	0.82	0.59	63	63
MAAC	0.35	0.19	15	15
EMAAC	0.00	0.00	1	1
BGE	0.00	0.00	1	1

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

Locational Deliverability Areas (LDAs)

Under the PJM Tariff, PJM determines, in advance of each BRA, whether defined Locational Deliverability Areas (LDAs) will be modeled in the auction. Effective with the 2012/2013 Delivery Year, an LDA is modeled as a potentially constrained LDA for a delivery year if the Capacity Emergency Transfer Limit (CETL) is less than 1.15 times the Capacity Emergency Transfer Objective (CETO), such LDA had a locational price adder in one or more of the three immediately preceding BRAs, or such LDA is determined by PJM in a preliminary analysis to be likely to have a locational price adder based on historic offer price levels. The rules also provide that starting with the 2012/2013 Delivery Year, EMAAC, SWMAAC, and MAAC LDAs are modeled as potentially constrained LDAs regardless of the results of the above three tests.[99] In addition, PJM may establish a constrained LDA even if it does not qualify under the above tests if PJM finds that "such is required to achieve an acceptable level of reliability."[100] A reliability requirement and a Variable Resource Requirement (VRR) curve are established for each modeled LDA. Effective for the 2014/2015 through 2016/2017 Delivery Years, a Minimum Annual and a Minimum Extended Summer Resource Requirement were established for each modeled LDA. Effective for the 2017/2018 Delivery Year, Sub-Annual and Limited Resource Constraints, replacing the Minimum Annual and a Minimum Extended Summer Resource Requirements, were established for each modeled LDA.[101] [102] Effective for the 2018/2019 and the 2019/2020 Delivery Years, a Base Capacity Demand Resource Constraint and a Base Capacity Resource Constraint, replacing the Sub-Annual and Limited Resource Constraints, were established for each modeled LDA.

Imports and Exports

Units external to the metered boundaries of PJM can qualify as PJM capacity resources if they meet the requirements to be capacity resources. Generators on the PJM system that do not have a commitment to serve PJM loads in the given delivery year as a result of RPM auctions, FRR capacity plans, locational UCAP transactions, and/or are not designated as a replacement resource, are eligible to export their capacity from PJM.[103]

The market rules in other balancing authorities should also not create inappropriate barriers to the import or export of capacity. The PJM market rules should ensure that the definition of capacity is enforced including physical deliverability, recallability and the obligation to make competitive offers into the PJM Day-Ahead Energy Market equal to ICAP MW. Physical deliverability can only be assured by requiring that all imports are deliverable to PJM load to ensure that they are full substitutes for internal capacity resources. Selling capacity into the PJM Capacity Market but making energy offers daily of $999 per MWh would not fulfill the requirements of a capacity resource to make a competitive offer, but would constitute economic withholding. This is one of the reasons that the rules governing the obligation to make a competitive offer in the day-ahead energy market should be clarified for both internal and external resources. The PJM market rules should also not create inappropriate barriers to either the import or export of capacity.

The calculation of CETL should only include capacity imports into PJM where the capacity has an explicit must offer requirement in the PJM Capacity Market. These could include pseudo tied units or resources with a grandfathered obligation. The external capacity that does not have a must offer requirement in the PJM capacity market is not obligated to serve PJM load under all conditions and therefore should not be assumed to be a source of capacity. This capacity should not be included in PJM's power flow calculations used to deriver CETL values between PJM's LDAs. PJM has modified its CETL calculations to exclude such capacity.

The establishment of a pseudo tie is one requirement for an external resource to be eligible to participate in the PJM Capacity Market. Pseudo tied external resources, regardless of their location, are treated as only meeting the reliability requirements of the rest of RTO and not the reliability requirements of any specific locational deliverability area (LDA). All imports offered in the auction from areas external to PJM are modeled as supply in the rest of RTO and not in any specific zonal or subzonal LDA. The fact that pseudo tied external

99 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.
100 OATT Attachment DD § 5.10 (a) (ii).
101 146 FERC ¶ 61,052 (2014).
102 Locational Deliverability Areas are shown in maps in the *2021 Annual State of the Market Report for PJM*, Volume II, Section 5, "Capacity Market" at "Locational Deliverability Areas (LDAs)".
103 OATT Attachment DD § 5.6.6(b).

resources cannot be identified as equivalent to resources internal to specific LDAs illustrates a fundamental issue with capacity imports. Capacity imports are not equivalent to, nor substitutes for, internal resources. All internal resources are internal to a specific LDA.[104]

Effective May 9, 2017, significantly improved pseudo tie requirements for external generation capacity resources were implemented.[105] The rule changes include: defining coordination with other Balancing Authorities when conducting pseudo tie studies; establishing an electrical distance requirement; establishing a market to market flowgate test to establish limits on the number of coordinated flowgates PJM must add in order to accommodate a new pseudo tie; a model consistency requirement; the requirement for the capacity market seller to provide written acknowledgement from the external Balancing Authority Areas that such pseudo tie does not require tagging and that firm allocations associated with any coordinated flowgates applicable to the external Generation Capacity Resource under any agreed congestion management process then in effect between PJM and such Balancing Authority Area will be allocated to PJM; the requirement for the capacity market seller to obtain long-term firm point to point transmission service for transmission outside PJM with rollover rights and to obtain network external designated transmission service for transmission within PJM; establishing an operationally deliverable standard; and modifying the nonperformance penalty definition for external generation capacity resources to assess performance at subregional transmission organization granularity.

Generation external to the PJM region is eligible to be offered into an RPM auction if it meets specific requirements.[106] [107] [108] Firm transmission service must be acquired from all external transmission providers between the unit and border of PJM and generation deliverability into PJM must be demonstrated prior to the start of the delivery year. In order to demonstrate generation deliverability into PJM, external generators must obtain firm point to point transmission service on the PJM OASIS from the PJM border into the PJM transmission system or by obtaining network external designated transmission service. In the event that transmission upgrades are required to establish deliverability, those upgrades must be completed by the start of the delivery year. The following are also required: the external generating unit must be in the resource portfolio of a PJM member; 12 months of NERC/GADs unit performance data must be provided to establish an EFORd; the net capability of each unit must be verified through winter and summer testing; and a letter of non-recallability must be provided to assure PJM that the energy and capacity from the unit is not recallable to any other balancing authority.

All external generation resources that have an RPM commitment or FRR capacity plan commitment or that are designated as replacement capacity must be offered in the PJM day-ahead energy market.[109]

Planned External Generation Capacity Resources are eligible to be offered into an RPM Auction if they meet specific requirements.[110] [111] 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.[112] An External Generation Capacity Resource becomes an Existing Generation Capacity Resource as of the earlier of the date that interconnection service commences or the resource has cleared an RPM Auction for a prior delivery year.[113]

104 External resources are not assigned to any of the five global LDAs or 22 zonal and subzonal LDAs. PJM's current practice is to model external resources in the rest of RTO. The practice is not currently documented by PJM. It was previously documented in "PJM Manual 18: PJM Capacity Market," § 2.3.4 Capacity Import Limits, Rev. 39 (Dec. 21, 2017).
105 161 FERC ¶ 61,197 (2017).
106 See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 9 & 10.
107 "PJM Manual 18: PJM Capacity Market," § 4.2.2 Existing Generation Capacity Resources – External, Rev. 58 (Nov. 15, 2023).
108 "PJM Manual 18: PJM Capacity Market," § 4.6.4 Importing an External Generation Resource, Rev. 58 (Nov. 15, 2023).
109 OATT Schedule 1 § 1.10.1A.
110 See "Reliability Assurance Agreement among Load Serving Entities in the PJM Region," Section 1.69A.
111 "PJM Manual 18: PJM Capacity Market," § 4.2.4 Planned Generation Capacity Resources – External, Rev. 58 (Nov. 15, 2023).
112 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).
113 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation. See 134 FERC ¶ 61,065 (2011).

As shown in Table 5-10, of the 1,527.1 MW of imports offered in the 2024/2025 RPM Base Residual Auction, 1,397.6 MW cleared. Of the cleared imports, 820.4 MW (58.7 percent) were from MISO.

Table 5-10 RPM imports: 2007/2008 through 2024/2025 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

Demand Resources

The level of DR products that buy out of their positions after the BRA means that the treatment of DR has a negative impact on generation investment incentives and that the rules governing the requirement to be a physical resource should be more clearly stated and enforced.[114] 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.

There are two categories of demand side products included in the RPM market design.[115] Demand Resources (DR) are interruptible load resources that offer in an RPM Auction as capacity and receive the relevant LDA or RTO resource clearing price. Energy Efficiency (EE) Resources are load resources that offer in an RPM Auction and receive the relevant LDA or RTO resource clearing price but EE resources are not capacity resources.

Effective with the 2020/2021 Delivery Year, DR and EE include annual and summer products. Annual Demand Resources are required to be available on any day during the Delivery Year for an unlimited number of interruptions between the hours of 10:00 a.m. and 10:00 p.m. EPT for the months of June through October and the following May and between the hours of 6:00 a.m. and 9:00 p.m. EPT for the months of November through April unless there is a PJM approved maintenance outage during the October through April period. Annual Energy Efficiency Resources are projects designed to achieve a continuous (during summer and winter peak periods) reduction in electric energy consumption during peak periods that is not reflected in the peak load forecast for the relevant delivery year, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention. EE resources are fully reflected in PJM load forecasts starting with the 2016 load forecast for the 2019/2020 delivery year, and EE resources should not be included in the capacity resources in any way as a result.

114 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).

115 See *2023 Annual State of the Market Report for PJM*, Volume II, Section 6: Demand Response for more details on the definitions of DR and EE.

Summer-Period Demand Resources are required to be available on any day from June through October and the following May of the delivery year for an unlimited number of interruptions between the hours of 10:00 a.m. to 10:00 p.m. EPT. Summer-Period Energy Efficiency Resources are projects designed to achieve a continuous (during summer peak periods) reduction in electric energy consumption during peak periods that is not reflected in the peak load forecast for the delivery year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention. The peak period definition for the Summer-Period Efficiency Resource type includes the period from the HE 1500 EPT and the HE 1800 EPT from June through August, excluding weekends and federal holidays. EE resources are fully reflected in PJM load forecasts starting with the 2016 load forecast for the 2019/2020 Delivery Year, and EE resources should not be included in the capacity resources in any way as a result.

As shown in Table 5-11, Table 5-12, and Table 5-13, committed DR was 7,707.9 MW for June 1, 2023, as a result of cleared capacity for demand resources in RPM auctions for the 2023/2024 Delivery Year (8,174.1 MW) less replacement capacity (466.2 MW). Committed EE was 5,891.1 MW for June 1, 2023, as a result of cleared MW in RPM auctions for the 2023/2024 Delivery Year (5,896.4 MW) less replacement MW (5.3 MW).

Table 5-11 RPM load management statistics by LDA: June 1, 2020 to June 1, 2024[116 117 118]

		UCAP (MW)														
		RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ATSI Cleveland	ComEd	BGE	PPL	DAY	DEOK
01-Jun-20	DR cleared	9,445.7	2,829.1	1,168.9	485.8	72.6	339.0	152.7	236.3	951.7	231.9	1,657.3	249.5	616.6	241.5	184.7
	EE cleared	3,569.5	1,288.8	700.3	394.5	28.8	246.1	111.3	196.2	356.0	72.9	852.0	198.3	111.4	79.5	105.6
	DR net replacements	(2,399.5)	(858.7)	(369.0)	(176.5)	(29.7)	(136.5)	(89.0)	(53.3)	(121.1)	(36.2)	(314.5)	(123.2)	(171.0)	(66.1)	(27.5)
	EE net replacements	(29.7)	(0.5)	(0.3)	5.9	0.0	(6.3)	12.0	(0.6)	(0.2)	0.0	(0.1)	6.5	(5.2)	0.0	(5.0)
	RPM load management	10,586.0	3,258.7	1,499.9	709.7	71.7	442.3	187.0	378.6	1,186.4	268.6	2,194.7	331.1	551.8	254.9	257.8
01-Jun-21	DR cleared	11,427.7	3,454.1	1,381.5	624.9	66.3	410.5	188.6	345.9	1,196.8	272.8	2,073.7	279.0	697.7	227.7	220.5
	EE cleared	4,806.2	1,810.5	979.1	501.1	42.0	353.1	136.0	275.9	420.5	95.7	982.7	225.2	186.7	111.0	135.5
	DR net replacements	(4,111.0)	(1,302.8)	(568.4)	(160.8)	(28.1)	(195.8)	(100.2)	(106.5)	(483.2)	(137.4)	(609.5)	(54.3)	(235.1)	(50.9)	(90.2)
	EE net replacements	(7.0)	0.0	0.0	(1.1)	0.1	0.0	34.9	(2.6)	80.0	7.0	10.6	1.5	(1.7)	8.0	(17.5)
	RPM load management	12,115.9	3,961.8	1,792.2	964.1	80.3	567.8	259.3	512.7	1,214.1	238.1	2,457.5	451.4	647.6	295.8	248.3
01-Jun-22	DR cleared	8,866.2	2,821.3	1,139.9	489.2	48.4	294.6	93.8	325.3	949.4	191.8	1,521.9	163.9	661.7	210.5	185.1
	EE cleared	5,734.8	2,303.6	1,265.3	499.4	53.5	431.0	201.6	287.5	485.0	55.9	792.6	211.9	312.4	129.4	186.8
	DR net replacements	(570.0)	(395.4)	(138.0)	(12.6)	1.7	(49.4)	(12.6)	(21.5)	(99.6)	(28.2)	127.5	8.9	(165.2)	(24.1)	24.3
	EE net replacements	(4.0)	11.8	7.0	14.9	0.0	(2.1)	15.4	8.7	(22.2)	(0.5)	0.0	6.2	(9.8)	(13.0)	0.0
	RPM load management	14,027.0	4,741.3	2,274.2	990.9	103.6	674.1	298.2	600.0	1,312.6	219.0	2,442.0	390.9	799.1	302.8	396.2
01-Jun-23	DR cleared	8,174.1	2,411.4	975.9	343.6	52.2	272.7	126.1	175.2	916.2	189.4	1,253.2	168.4	583.4	209.3	175.4
	EE cleared	5,896.4	2,438.6	1,341.4	569.5	59.3	443.4	210.4	298.6	451.8	46.3	961.2	270.9	306.1	102.4	164.3
	DR net replacements	(466.2)	(229.5)	(3.8)	(4.9)	22.8	3.4	2.6	(25.0)	47.2	(63.4)	160.7	20.1	(123.3)	(24.0)	25.0
	EE net replacements	(5.3)	(2.2)	(1.0)	7.6	9.0	11.6	13.7	7.6	(15.3)	(0.5)	(20.9)	0.0	(6.2)	(7.9)	0.7
	RPM load management	13,599.0	4,618.3	2,312.5	915.8	143.3	731.1	352.8	456.4	1,399.9	171.8	2,354.2	459.4	760.0	279.8	365.4
01-Jun-24	DR cleared	8,065.2	2,505.1	1,001.0	362.6	42.1	285.7	98.2	164.5	682.6	141.6	1,552.1	198.1	608.7	192.9	221.9
	EE cleared	7,717.5	3,545.0	2,064.9	787.4	99.9	802.9	392.0	398.9	587.6	54.9	1,063.4	388.5	392.9	128.3	188.1
	DR net replacements	(48.5)	(11.6)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(3.6)	0.0	(4.4)	0.0	(7.2)
	EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	RPM load management	15,734.2	6,038.5	3,065.9	1,150.0	142.0	1,088.6	490.2	563.4	1,270.2	196.5	2,611.9	586.6	997.2	321.2	402.8

116 See OATT Attachment DD § 8.4. The reported DR cleared MW may reflect reductions in the level of committed MW due to relief from Capacity Resource Deficiency Charges.
117 Pursuant to OA § 15.1.6(c), PJM Settlement shall attempt to close out and liquidate forward capacity commitments for PJM Members that are declared in collateral default. The reported replacement transactions may include transactions associated with PJM members that were declared in collateral default.
118 See OATT Attachment DD § 5.14E. The reported DR cleared MW for the 2016/2017, 2017/2018, and 2018/2019 Delivery Years reflect reductions in the level of committed MW due to the Demand Response Legacy Direct Load Control Transition Provision.

Table 5-12 RPM commitments, replacements, and registrations for demand resources: June 1, 2007 to June 1, 2024[119 120 121]

	UCAP (MW)						Registered DR		
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM Commitment Shortage	RPM Commitments Less Commitment Shortage	ICAP (MW)	UCAP Conversion Factor	UCAP (MW)
01-Jun-07	127.6	0.0	0.0	127.6	0.0	127.6	0.0	1.033	0.0
01-Jun-08	559.4	0.0	(40.0)	519.4	(58.4)	461.0	488.0	1.034	504.7
01-Jun-09	892.9	0.0	(474.7)	418.2	(14.3)	403.9	570.3	1.033	589.2
01-Jun-10	962.9	0.0	(516.3)	446.6	(7.7)	438.9	572.8	1.035	592.6
01-Jun-11	1,826.6	0.0	(1,052.4)	774.2	0.0	774.2	1,117.9	1.035	1,156.5
01-Jun-12	8,752.6	(11.7)	(2,253.6)	6,487.3	(34.9)	6,452.4	7,443.7	1.037	7,718.4
01-Jun-13	10,779.6	0.0	(3,314.4)	7,465.2	(30.5)	7,434.7	8,240.1	1.042	8,586.8
01-Jun-14	14,943.0	0.0	(6,731.8)	8,211.2	(219.4)	7,991.8	8,923.4	1.042	9,301.2
01-Jun-15	15,774.8	(321.1)	(4,829.7)	10,624.0	(61.8)	10,562.2	10,946.0	1.038	11,360.0
01-Jun-16	13,284.7	(19.4)	(4,800.7)	8,464.6	(455.4)	8,009.2	8,961.2	1.042	9,333.4
01-Jun-17	11,870.7	0.0	(3,870.8)	7,999.9	(30.3)	7,969.6	8,681.4	1.039	9,016.3
01-Jun-18	11,435.4	0.0	(3,182.4)	8,253.0	(1.0)	8,252.0	8,512.0	1.091	9,282.4
01-Jun-19	10,703.1	0.0	(2,138.8)	8,564.3	(0.4)	8,563.9	9,229.9	1.090	10,056.0
01-Jun-20	9,445.7	0.0	(2,399.5)	7,046.2	(0.1)	7,046.1	7,867.6	1.088	8,561.5
01-Jun-21	11,427.7	0.0	(4,111.0)	7,316.7	0.0	7,316.7	7,754.2	1.087	8,429.6
01-Jun-22	8,866.2	0.0	(570.0)	8,296.2	(52.1)	8,244.1	8,518.5	1.091	9,290.2
01-Jun-23	8,174.1	0.0	(466.2)	7,707.9	(161.5)	7,546.4	7,383.0	1.093	8,069.6
01-Jun-24	8,065.2	0.0	(48.5)	8,016.7	0.0	8,016.7	112.7	1.117	125.9

119 See OATT Attachment DD § 8.4. The reported DR adjustments to cleared MW include reductions in the level of committed MW due to relief from Capacity Resource Deficiency Charges.
120 See OATT Attachment DD § 5.14C. The reported DR adjustments to cleared MW for the 2015/2016 and 2016/2017 Delivery Years include reductions in the level of committed MW due to the Demand Response Operational Resource Flexibility Transition Provision.
121 See OATT Attachment DD § 5.14E. The reported DR adjustments to cleared MW for the 2016/2017, 2017/2018, and 2018/2019 Delivery Years include reductions in the level of committed MW due to the Demand Response Legacy Direct Load Control Transition Provision.

Table 5-13 RPM commitments and replacements for energy efficiency resources: June 1, 2007 to June 1, 2024[122] [123]

	UCAP (MW)					
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM Commitment Shortage	RPM Commitments Less Commitment Shortage
01-Jun-07	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-08	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-09	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-10	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-11	76.4	0.0	0.2	76.6	0.0	76.6
01-Jun-12	666.1	0.0	(34.9)	631.2	(5.1)	626.1
01-Jun-13	904.2	0.0	120.6	1,024.8	(13.5)	1,011.3
01-Jun-14	1,077.7	0.0	204.7	1,282.4	(0.2)	1,282.2
01-Jun-15	1,189.6	0.0	335.9	1,525.5	(0.9)	1,524.6
01-Jun-16	1,723.2	0.0	61.1	1,784.3	(0.5)	1,783.8
01-Jun-17	1,922.3	0.0	195.6	2,117.9	(7.4)	2,110.5
01-Jun-18	2,296.3	0.0	248.8	2,545.1	0.0	2,545.1
01-Jun-19	2,528.5	0.0	(50.0)	2,478.5	0.0	2,478.5
01-Jun-20	3,569.5	0.0	(29.7)	3,539.8	(0.1)	3,539.7
01-Jun-21	4,806.2	0.0	(7.0)	4,799.2	0.0	4,799.2
01-Jun-22	5,734.8	0.0	(4.0)	5,730.8	0.0	5,730.8
01-Jun-23	5,896.4	0.0	(5.3)	5,891.1	(30.1)	5,861.0
01-Jun-24	7,717.5	0.0	0.0	7,717.5	0.0	7,717.5

Capacity Value of Intermittent Resources (ELCC)

Given that states have increasingly aggressive renewable energy targets, a core goal of a competitive market design should be to ensure that the resources required to provide reliability receive appropriate competitive market incentives for entry and for ongoing investment and for exit when uneconomic. A significant level of renewable resources, operating with zero or near zero marginal costs, will result in very low energy prices at times of high intermittent output. Since renewable resources are intermittent, the contribution of renewables to meeting reliability targets must be analyzed carefully to ensure that the capacity value of renewables is calculated correctly.

The contribution of intermittent and storage resources to reliability has been addressed in the PJM capacity market using derating factors in order to help ensure that MW of capacity are comparable, regardless of the source. Derating factors based on average generation during summer peak hours were used prior to the 2023/2024 Delivery Year to determine capacity values for wind and solar generators.[124] On July 30, 2021, FERC approved new rules in PJM for determining the capacity value of intermittent generators based on the effective load carrying capability (ELCC) method.[125] The MMU opposed PJM's ELCC rules because they relied on significant counterfactual behavioral assumptions for storage and demand response resources, did not apply to all resource types, used invented (putative) data, used average technology values, were not locational, and provided for a long term guarantee of high average ELCC values for existing resources, among other issues.[126] PJM's ELCC approach is an ex ante, administrative determination by PJM based on a black box model, of the capacity value of resources. The ELCC values are on a class average technology class basis with no recognition of locational differences and no opportunity to recognize actual performance in the delivery year. PJM does not check the actual cleared capacity in capacity market auctions to verify if the cleared capacity is expected to provide the target reliability. Capacity values determined by the PJM average ELCC approach are being used for the 2023/2024 and 2024/2025 Delivery Years.

The ELCC approach is not an appropriate way to define the MW capacity value for intermittent and storage resources, or for thermal resources, in a market. ELCC was developed as, and remains, a utility planning tool rather than a market design tool. ELCC was attractive as a possible analytical basis for the derating of intermittent and storage resources to a MW level consistent with their actual availability and consistent with a perfect resource, or at least a thermal resource. The impetus made sense but the actual application of the ELCC planning tool cannot work in markets that include intermittent or thermal resources. The underlying logic makes sense. Neither intermittent nor thermal resources are the perfect resource. There are thermal resources,

122 Pursuant to the OA § 15.1.6(c), PJM Settlement shall close out and liquidate all forward positions of PJM members that are declared in default. The replacement transactions reported for the 2014/2015 Delivery Year included transactions associated with RTP Controls, Inc., which was declared in collateral default on March 9, 2012.

123 Effective with the 2019/2020 Delivery Year, available capacity from an EE Resource can be used to replace only EE Resource commitments. This rule change and related EE addback rule changes were endorsed at the December 17, 2015, meeting of the PJM Markets and Reliability Committee.

124 *Class Average Capacity Factors – Wind and Solar Resources*, PJM Interconnection L.L.C. (June 1, 2017).

125 See 176 FERC ¶ 61,056 (2021). There are multiple ways to apply the ELCC method. There is not a single ELCC method.

126 182 FERC ¶ 61,109 (2023).

currently credited with full capacity value, that are much less available than some intermittent resources that are derated.

PJM's approach to ELCC is based on correct insights about the need to calculate the availability of different resource types but the actual implementation results in a set of illogical implications. For example, PJM assigned penalties to solar resources during Winter Storm Elliott in December 2022 when solar resources did not generate power after dark.

Under the PJM ELCC approach a solar resource is assigned a derating factor, the derated MW are equivalent to a perfect resource accredited at that MW level. PJM assigned penalties to solar resources during Elliott when they did not generate power after dark. This is clearly not correct and illustrates one of the flaws in the ELCC logic. The solar resource is available for sunny hours and not for unsunny hours. A solar resource is not expected to generate at night and should not face penalties for failing to do what it obviously cannot. ELCC does not convert intermittent resources, or any resource, into a perfect resource, or even the equivalent of a perfect resource. This illogical implication of PJM's ELCC means that there is a significant flaw in the ELCC approach. The penalties were assessed because the ELCC method determined that 1 MW of solar nameplate capacity was equivalent to 0.54 MW of perfect capacity, meaning capacity that is always available at the derated level, even in the middle of the night.[127] As a result of all these issues, the MMU has concluded that ELCC is not a viable method for determining the reliability contributions of intermittent and storage resources, or for thermal resources. The MMU has proposed a replacement for the PJM ELCC approach that is based on the actual hourly availability of all individual generators.[128]

On January 30, 2024, FERC accepted PJM's latest version of ELCC that will apply beginning with the 2025/2026 Delivery Year.[129] This latest version is a marginal ELCC approach in which the ELCC class rating should represent the carrying capability of an additional MW of ICAP for the resource class. In addition to intermittent and storage resources, the approach is used to determine the capacity values for thermal resources and demand resources. Most of the issues with the prior average ELCC approach also apply to the new marginal approach. The new marginal approach relies on significant counterfactual behavioral assumptions for storage and demand resources, uses invented (putative) data, is not locational, and is an ex ante approach that must assume a capacity resource fleet for determining the ELCC marginal class ratings. Once the capacity auction reveals the actual capacity resource fleet, PJM simply assumes the resources that cleared the auction will have the same marginal ratings. As in the previous average ELCC implementation, there are no plans to recalculate the ELCC ratings for the cleared capacity fleet. The underlying flaws of the ELCC approach have not been resolved and in fact cannot be resolved. Solar resources will still be penalized for not generating at night if there is a performance assessment event. To compensate for this clearly illogical and unfair rule, solar and other intermittent resources are not required to participate in the capacity market. Thus PJM has come full circle. One of the primary reasons for moving to the ELCC approach was in anticipation of increased reliance on intermittent resources for capacity. PJM has now implemented a new, complicated capacity accreditation process, which works so badly for intermittent resources that they are not required to participate in the capacity market.

The capacity derating factors applied to intermittent nameplate capacity the 2022/2023 Delivery Year and the ELCC calculations used for the 2023/2024 and the 2024/2025 Delivery Years are based on the assumption that the intermittent resources provide reliable output in excess of their CIRs. But that output is not deliverable when needed for reliability because it is in excess of the defined deliverability rights (CIRs) and therefore should not be included in the definition of intermittent capacity. The preferable solution is to require intermittent resources to purchase CIRs equal to the maximum energy output assumed in the derating calculation. That is the solution reached in the PJM stakeholder process.[130] The corresponding performance obligation of an intermittent resource is to produce at its corresponding maximum energy

127 "ELCC Class Ratings for 2024-2025 BRA," PJM Interconnection L.L.C. (December 28, 2021) <https://www.pjm.com/planning/resource-adequacy-planning/effective-load-carrying-capability>.
128 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>.
129 186 FERC ¶ 61,080 (2024).
130 ELCC/CIR discussions were held throughout 2022 during the PC Special Session – CIRs for ELCC Resources as well as the MC and the MRC <https://www.pjm.com/committees-and-groups/issue-tracking/issue-tracking-details.aspx?Issue=83aadda8-b6c1-4630-9483-025b6b93fc28>.

output level when it is possible, based on wind and solar conditions. After a lengthy stakeholder process, on April 7, 2023, FERC approved updates to PJM's ELCC method that cap the level of an intermittent generator's output used to calculate the generator's reliability contribution (ELCC derated MW) at the generator's CIR level.[131]

The definition of intermittent capacity is thus not consistent with the way that capacity is defined. This results in an overstatement of the supply of capacity and reduces the clearing price in the capacity market. The MMU recommends that intermittent resources, including storage, not be permitted to offer capacity MW based on energy delivery that exceeds their defined deliverability rights (CIRs). Only energy output for such resources below the designated CIR/deliverability level should be recognized in the definition of capacity. There is the related issue of ensuring that intermittent resources, like all other resources, are required to pay their own interconnection costs in order to meet their attributed capacity value, consistent with the longstanding PJM market design, or reduce their capacity value.

Generation owners of intermittent resources and environmentally limited resources can request winter capacity interconnection rights (CIRs).[132] 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. 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

131 183 FERC ¶61,009.
132 OATT Part VII, Subpart E § 332.

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.

Market Conduct

Offer Caps

Market power mitigation measures were applied to capacity resources such that the sell offer was set equal to the defined offer cap when the capacity market seller failed the market structure test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would have increased the market clearing price.[133] [134] [135] For Capacity Performance Resources, for RPM auctions prior to September 2, 2021, offer caps are defined in the PJM Tariff as the applicable zonal Net Cost of New Entry (CONE) times (B) where B is the average of the Balancing Ratios (B) during the Performance Assessment Hours in the three consecutive calendar years that precede the base residual auction for such delivery year, unless net avoidable costs exceed this level, or opportunity costs based on the potential sale of capacity in an external market exceed this level. The Commission issued an order eliminating the prior offer cap and establishing a competitive market seller offer cap set at Net ACR, effective September 2, 2021.[136] The Commission rejected a more recent attempt to undermine the Market Seller Offer Cap rules by order issued February 6, 2024.[137]

For RPM Third Incremental Auctions prior to September 2, 2021, capacity market sellers may elect an offer cap equal to the greater of the Net CONE for the relevant LDA and delivery year or 1.1 times the BRA clearing price for the relevant LDA and delivery year. For RPM Third Incremental Auctions after September 2, 2021, capacity market sellers may elect an offer cap of 1.1 times the BRA clearing price for the relevant LDA and delivery year.

133 See OATT Attachment DD § 6.5.
134 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 at P 30 (2009).
135 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).
136 176 FERC ¶ 61,137 (2021), *order denying reh'g*, 178 FERC ¶ 61,121 (2022), *appeal denied*, EPSA, et al. v. FERC, Case No. 21-1214, et al. (DC Cir. October 10, 2023), *cert. pending*.
137 186 FERC ¶ 61,097, *reh'g denied*, 187 FERC ¶ 62,016 (2024).

Avoidable costs are costs that are neither short run marginal costs, like fuel or consumables, nor fixed costs like depreciation and rate of return. Avoidable costs are the costs that a generation owner incurs as a result of operating a generating unit for one year, in particular the delivery year.[138] As a result, the tariff defines avoidable costs as the costs that a generation owner would not incur if the generating unit did not offer for one year. Although the term mothball is used in the tariff to modify the term ACR, the term mothball is not defined in the tariff. Mothball is an informal term better understood as a metaphor for the cost to operate for one year. Avoidable costs are the costs to operate the unit for one year, regardless of whether the unit plans to retire. Although the tariff includes different mothball and retirement values, the distinction is based on a misunderstanding of the meaning of avoidable costs and should be eliminated. PJM never explained exactly how it calculated mothball and retirement avoidable cost levels. The MMU recommends that major maintenance costs be included in the definition of avoidable costs and removed from energy offers because such costs are avoidable costs and not short run marginal costs.[139] The tariff states that avoidable costs may also include annual capital recovery associated with investments required to maintain a unit as a Generation Capacity Resource, termed Avoidable Project Investment Recovery (APIR), despite the fact that these are not actually avoidable costs, particularly after the first year.

Avoidable cost based offer caps are defined to be net of revenues from all other PJM markets and unit-specific bilateral contracts, including RECs, and expected bonus performance payments/nonperformance charges.[140] 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.[141]

138 OATT Attachment DD § 6.8 (b).
139 *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).
140 For details on the competitive offer of a capacity performance resource, see "Analysis of the 2023/2024 RPM Base Residual Auction," <https://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf> (October 28, 2022).
141 OATT Attachment DD § 6.8(a).

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).[142] AFAE is available for Capacity Performance Resources. AFAE is defined to include expenses related to fuel availability and delivery. CPQR is available for Capacity Performance Resources and, for the 2018/2019 and 2019/2020 Delivery Years, Base Capacity Resources. CPQR is defined to be the quantifiable and reasonably supported cost of mitigating the risks of nonperformance associated with submission of an offer.

The opportunity cost option allows capacity market sellers to offer based on a documented price available in a market external to PJM, subject to export limits. If the relevant RPM market clears above the opportunity cost, the generation capacity resource is sold in the RPM market. If the opportunity cost is greater than the clearing price and the generation capacity resource does not clear in the RPM market, it is available to sell in the external market.

Competitive Offers

The competitive offer of a capacity resource is based, regardless of tariff requirements, on a market seller's expectations of a number of variables, some of which are resource specific: the resource's net going forward costs (net ACR), the resource's gross ACR, and the resource's forward looking net revenues. The gross ACR includes the cost to mitigate the resource's risk of incurring performance assessment penalties.

The competitive offer is based on a forward looking energy and ancillary services (E&AS) net revenue offset rather than the backward looking E&AS net revenue offset currently in the tariff. Forward prices for energy prices and fuel prices are a better guide to market expectations than historical energy and fuel prices. This is particularly important in years, like 2022, when there is a significant change from the historical level of energy market prices. The actual prices in 2022 are about 120 percent higher through the end of September than prices for the same period in 2021. The forward curves reflect this change, but the historical prices do not.

142 151 FERC ¶ 61,208 (2015).

PJM had a forward looking net revenue calculation in the tariff that applied to RPM Auctions for the 2022/2023 Delivery Year.[143] FERC subsequently reversed its approval of that method as part of rejecting PJM's ORDC filing.[144] PJM's method for calculating forward looking E&AS net revenues was flawed for several reasons. PJM's method included an adjustment based on the prices of long term FTRs for the planning period closest in time to the delivery year which requires an adjustment for monthly average day-ahead congestion price differentials and an adjustment for loss component differentials of historical LMPs. Use of the adjustment based on the prices of long term FTRs adds unnecessary complexity, fails to make the result more accurate, makes the results less transparent, and in some cases make the results less accurate. PJM's use of long term FTRs in the forward energy market price calculation does not use the FTR auction for the desired delivery year as a result of the timing of capacity auctions and FTR auctions when PJM is on its defined three year capacity market auction schedule. It would be simpler, more accurate and more transparent to use forward LMPs calculated using real-time monthly on and off peak forward prices for the delivery year at the PJM Western Hub, adjusted to the zone and hour using the historical zonal, nodal and hourly real-time price differentials for each of the last three years. The MMU and PJM have been implementing this method for years in the calculation of the opportunity costs associated with environmental limits on the operation of generating units.[145]

More fundamentally, PJM's forward looking net revenue calculation tends to overestimate forward net revenues. The PJM method is based on a theoretical, unit by unit perfect dispatch based on unit parameters and forward fuel costs and LMPs. The PJM method fails to account for the realities of committing and dispatching units. Nonetheless, it remains correct that generation owners look forward and not backwards when calculating net revenues. The goal is an approach that retains the reality of historical commitment and dispatch while recognizing that future conditions will be different. A better approach would calculate unit forward looking expected energy and ancillary services net revenues using historical revenues that are scaled based on a comparison of forward prices for energy and fuel to the historical prices for energy and fuel.

The competitive offer of a capacity resource is based on a market seller's expectations of market variables during the delivery year, the impact of these variables on the resource's risk, and the cost to mitigate that risk. These market variables are: the number of performance assessment intervals (PAI) in a delivery year where the resource is located; the level of performance required to meet its capacity obligation during those performance assessment intervals, measured as the average Balancing Ratio (B); and the level of the bonus performance payment rate (CPBR) compared to the nonperformance charge rate (PPR). The total capacity revenues earned by a resource are the sum of revenues earned in the forward capacity auctions and additional bonus revenues earned (or penalties paid) during the delivery year, which are a function of unit performance during PAI (A). The level of the bonus performance payment rate depends on the level of underperforming MW net of the underperforming MW excused by PJM during performance assessment intervals for reasons defined in the PJM OATT.[146]

Under the original Capacity Performance design, the competitive offer of a resource was the larger of the asserted opportunity cost of taking on a CP obligation (the default offer cap), or a unit specific offer cap based on its net ACR. But the default offer cap defined in the PJM tariff was based on strong assumptions that are not correct.

The circular logic of the offer cap derivation inevitably concluded that Net CONE times B was the competitive offer. The derivation is based on the assumption that Net CONE is the target clearing price for the capacity market. That assumption is the basis for using Net CONE as the penalty rate. The penalty rate, adjusted for the reduced obligation defined by B, equals the market seller offer cap. The derivation is also based on the assumption that capacity resources have the ability to costlessly switch between capacity resource status and energy only status. That assumption is the basis for

143 171 FERC ¶ 61,153 (May 21, 2020) and 173 FERC ¶ 61,134 (November 12, 2020).
144 Forward energy and ancillary services (E&AS) revenue offsets were applicable from November 12, 2020, as approved in the FERC Order on compliance in Docket Nos. EL19-58-002 and EL19-58-003 until December 22, 2021, when the Commission issued an Order on Voluntary Remand in Docket Nos. EL19-58-006 and ER19-1486-003 reversing its prior determination that PJM should use a forward looking energy E&AS revenue offset and directing PJM to submit a compliance filing restoring the tariff provisions defining the historical E&AS revenue offset.
145 *See* "PJM Manual 15: Cost Development Guidelines," § 12.7 IMM Opportunity Cost Calculator, Rev. 44 (Aug. 1, 2023).
146 OATT Attachment DD § 10A (d).

the assertion that an offer in the capacity market has an opportunity cost associated with the ability to be an energy only resource. But there is no such opportunity cost. The use of the offer cap is also based on a third demonstrably false assumption that competitive forces in the PJM Capacity Market would produce competitive outcomes despite an offer cap that was above the competitive level.

The offer cap derivation also included some additional unsupported and incorrect assumptions: there are a reasonably expected number of PAI; the number of PAI used in the calculation of the nonperformance charge rate is the same as the expected PAI (360); the number of performance intervals that define the total payments must equal the denominator of the performance penalty rate; the bonus payment rate for units that overperform equals the penalty rate for units that underperform; and penalties are imposed by PJM for all cases of noncompliance as defined in the tariff and there are no excuses.

The PJM Capacity Market has a must offer requirement for a reason; it is required in order to ensure that the market can work, given the must buy obligation of load. A key ancillary benefit is that the must offer requirement helps prevent the exercise of market power by preventing withholding. The purpose of the must offer requirement is also to ensure equal and open access to the 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. If a capacity market seller wants to convert to energy only status, the owner must give up its CIRs. Such CIRs are likely to be expensive and difficult to reacquire if the capacity market seller decided to reenter the capacity market.

Net CONE times B was clearly well in excess of a competitive offer in the 2021/2022 BRA and 2022/2023 BRA whether compared to net ACR offers or compared to the actual offers of market participants. While the offer cap provided almost unlimited optionality to generation owners in setting offers, the actual clearing prices based on actual offers were generally about half of the offer caps. But some generation owners did successfully exercise market power within this design.

The September 2, 2021, Commission order addressed the definition of the market seller offer cap by eliminating the net CONE times B offer cap and establishing a competitive market seller offer cap of net ACR.[147]

The Commission rejected a more recent attempt to undermine the Market Seller Offer Cap rules by order issued February 6, 2024.[148]

2024/2025 RPM Third Incremental Auction

As shown in Table 5-14, 316 generation resources submitted Capacity Performance offers in the 2024/2025 RPM Third Incremental Auction. Unit specific offer caps were calculated for seven generation resources (2.2 percent). Of the 316 generation resources, 216 generation resources elected the offer cap option of 1.1 times the BRA clearing price (68.4 percent), 62 generation resources had default ACR based offer caps (19.6 percent), five generation resources had unit specific ACR based offer caps (1.5 percent), two generation resource had a unit specific opportunity cost based offer cap (0.6 percent), two Planned Generation Capacity Resources had uncapped offers (0.6 percent), and the remaining 29 generation resources were price takers (9.2 percent). Market power mitigation was applied to six Capacity Performance sell offers. The 2024/2025 RPM Third Incremental Auction may be rerun.[149]

147 176 FERC ¶ 61,137 (2021), *order denying reh'g*, 178 FERC ¶ 61,121 (2022), *appeal denied*, EPSA, et al. v. FERC, Case No. 21-1214, et al. (DC Cir. October 10, 2023).
148 186 FERC ¶ 61,097, *reh'g denied*, 187 FERC ¶ 62,016 (2024).
149 The Commission orders addressing the issue with the DPL South reliability requirement were reversed on appeal. PJM proposed to the Commission that PJM withdraw the auction results under the rejected rules, calculate the results under the prior flawed rules, and rerun an incremental auction to adjust to the new results. Commission action on the matter is pending.

Table 5-14 ACR statistics: RPM auctions held in first quarter, 2024

	2024/2025 Third Incremental Auction	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	62	19.6%
Unit specific ACR (APIR)	3	0.9%
Unit specific ACR (APIR and CPQR)	0	0.0%
Unit specific ACR (non-APIR)	2	0.6%
Unit specific ACR (non-APIR and CPQR)	0	0.0%
Opportunity cost input	2	0.6%
Default ACR and opportunity cost	0	0.0%
Net CONE times B	NA	NA
Offer cap of 1.1 times BRA clearing price elected	216	68.4%
Uncapped planned uprate and default ACR	0	0.0%
Uncapped planned uprate and opportunity cost	0	0.0%
Uncapped planned uprate and Net CONE times B	NA	NA
Uncapped planned uprate and price taker	0	0.0%
Uncapped planned uprate and 1.1 times BRA clearing price elected	0	0.0%
Uncapped planned generation resources	2	0.6%
Existing generation resources as price takers	29	9.2%
Total Generation Capacity Resources offered	316	100.0%

MOPR

By order issued December 19, 2019, the RPM Minimum Offer Price Rule (MOPR) was modified.[150] The rules applying to natural gas fired capacity resources without state subsidies were retained. The changes included expanding the MOPR to new or existing state subsidized capacity resources; establishing a competitive exemption for new and existing resources other than natural gas fired resources while also allowing a resource specific exception process for those that do not qualify for the competitive exemption; defining limited categorical exemptions for renewable resources participating in renewable portfolio standards (RPS) programs, self supply, DR, EE, and capacity storage; defining the region subject to MOPR for capacity resources with state subsidy as the entire RTO; and defining the default offer price floor for capacity resources with state subsidies as 100 percent of the applicable Net CONE or net ACR values.

The Commission convened a Technical Conference on March 23, 2021, in order to consider whether MOPR should be retained and to consider possible alternative approaches.[151] The MMU testified at the Technical Conference and provided comments and responses to the Commission's questions following the conference.[152]

On September 29, 2021, PJM's FPA section 205 filing in Docket No. ER21-2582-000 revising the Minimum Offer Price Rule (MOPR) was made effective by operation of law.[153] 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 would 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 has defined it.[154]

The Commission approved PJM's proposed revisions to the PJM market rules to implement a forward looking E&AS offset to include forward looking energy and ancillary services revenues rather than historical.[155] The change in the offset affected MOPR floor prices and the results of unit specific reviews under

150 169 FERC ¶ 61,239 (2019), *order denying reh'g*, 171 FERC ¶ 61,035 (2020), *aff'd* PJM Power Providers Group, et al. v. FERC, Case No. 21-3068 (December 1, 2023), *cert pending.*

151 Technical Conference regarding Resource Adequacy in the Evolving Electricity Sector, Docket No. AD21-10 (March 23, 2021).
152 *Modernizing Electricity Market Design*, Comments of the Independent Market Monitor for PJM, Docket No. AD21-10 (April 26, 2021).
153 *PJM Interconnection, L.L.C*, Notice of Filing Taking Effect by Operation of Law, Docket No. ER21-2582 (September 29, 2021).
154 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).
155 173 FERC ¶ 61,134 (2020).

MOPR in the 2023/2024 BRA. This decision was reversed in the Commission's order related to the ORDC matter.[156]

MOPR Statistics

Under the applicable MOPR rules, market power mitigation measures were applied to MOPR Screened Generation Resources such that the sell offer is set equal to the MOPR Floor Offer Price when the submitted sell offer is less than the MOPR Floor Offer Price and an exemption or exception was not granted, or the sell offer is set equal to the agreed upon minimum level of sell offer when the sell offer is less than the agreed upon minimum level of sell offer based on a Unit-Specific Exception or Resource-Specific Exception.

As shown in Table 5-15, there were no unit specific exception requests for MOPR under OATT Attachment DD § 5.14(h-2) for the 2024/2025 RPM Third Incremental Auction. Of the 734.0 MW offered in the 2024/2025 RPM Third Incremental Auction that were subject to MOPR, 673.3 MW cleared and 60.7 MW did not clear.

Table 5-15 MOPR statistics: RPM auctions held in first quarter, 2024

				ICAP (MW)			UCAP (MW)	
	MOPR Type	Calculation Type	Number of Requests	Requested	MMU Agreed	Offered	Offered	Cleared
2024/2025 Third Incremental Auction	OATT Attachment DD § 5.14(h-2)	Unit Specific Exception	0	0.0	0.0	0.0	0.0	0.0
	OATT Attachment DD § 5.14(h-2)	Default	NA	NA	NA	833.3	734.0	673.3
	Total		0	0.0	0.0	833.3	734.0	673.3

Replacement Capacity[157]

When a capacity resource is not available for a delivery year, the owner of the capacity resource may purchase replacement capacity. Replacement capacity is the vehicle used to offset any reduction in capacity from a resource which is not available for a delivery year. But the replacement capacity mechanism may also be used to manipulate the market.

Table 5-16 shows the committed and replacement capacity for all capacity resources for June 1 of each year from 2007 through 2024. The 2024 numbers are not final.

Sellers of demand resources in RPM auctions disproportionately replace those commitments on a consistent basis compared to sellers of other resource types. External generation and internal generation not in service had high rates of replacement in some years and those are also of concern.

The dynamic that can result is that the speculative DR suppresses prices in the BRA and displaces physical generation assets. Those generation assets then have an incentive to offer at a low price, including offers at zero and below cost, in IAs in order to ensure some capacity market revenue for long lived physical resources which the owners expect to maintain for multiple years. The result is lower IA prices which permit the buyback of the speculative DR at prices below the BRA prices which encourages the greater use of speculative DR.

PJM's sale of capacity in IAs at very low prices, given that PJM announces the MW quantity and the sell offer price in advance of the auctions, further reduces IA prices and increases the incentive of DR sellers to speculate in the BRAs. The MMU recommends that if PJM sells capacity in incremental auctions, PJM should offer the capacity for sale at the BRA clearing price in order to avoid suppressing the IA price below the competitive level. If the PJM sell offer price is not the BRA clearing price, PJM should not reveal its proposed sell offer price or the MW quantity to be sold prior to the auction.

It has been asserted that selling at a high price in the BRA and buying back at a low price in the IA is just a market transaction and therefore does not constitute a problem. But permitting DR to be an option in the BRA rather than requiring DR to be a commitment to provide a physical asset gives DR an unfair advantage and creates a self fulfilling dynamic that incents more of the same behavior. Only DR is permitted to be an option in the BRA.

156 177 FERC ¶ 61,209 (2021).
157 For more details on replacement capacity, see "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).

Generation resources must have met physical milestones in order to offer in the BRA. It is not reasonable to permit DR capacity resources to have a different product definition than generation capacity resources. Even if DR is treated as an annual product, this unique treatment as an option makes DR an inferior resource and not a complete substitute for generation resources. The current approach to DR is also inconsistent with the history of the definition of capacity in PJM, which has always been that capacity is physical and unit specific. The current approach to DR effectively makes DR a virtual participant in the PJM Capacity Market. That option should be eliminated.

The definition of demand side resources in PJM capacity markets is flawed in a variety of ways. The current demand side definition should be replaced with a definition that includes demand on the demand side of the market. There are ways to ensure and enhance the vibrancy of demand side without negatively affecting markets for generation. There are other price formation issues in the capacity market that should also be examined and addressed.[158]

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

Table 5-16 RPM commitments and replacements for all Capacity Resources: June 1, 2007 to June 1, 2024

	UCAP (MW)					
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM Commitment Shortage	RPM Commitments Less Commitment Shortage
01-Jun-07	129,409.2	0.0	0.0	129,409.2	(8.1)	129,401.1
01-Jun-08	130,629.8	0.0	(766.5)	129,863.3	(246.3)	129,617.0
01-Jun-09	134,030.2	0.0	(2,068.2)	131,962.0	(14.7)	131,947.3
01-Jun-10	134,036.2	0.0	(4,179.0)	129,857.2	(8.8)	129,848.4
01-Jun-11	134,182.6	0.0	(6,717.6)	127,465.0	(79.3)	127,385.7
01-Jun-12	141,295.6	(11.7)	(9,400.6)	131,883.3	(157.2)	131,726.1
01-Jun-13	159,844.5	0.0	(12,235.3)	147,609.2	(65.4)	147,543.8
01-Jun-14	161,214.4	(9.4)	(13,615.9)	147,589.1	(1,208.9)	146,380.2
01-Jun-15	173,845.5	(326.1)	(11,849.4)	161,670.0	(1,822.0)	159,848.0
01-Jun-16	179,773.6	(24.6)	(16,157.5)	163,591.5	(924.4)	162,667.1
01-Jun-17	180,590.5	0.0	(13,982.7)	166,607.8	(625.3)	165,982.5
01-Jun-18	175,996.0	0.0	(12,057.8)	163,938.2	(150.5)	163,787.7
01-Jun-19	177,064.2	0.0	(12,300.3)	164,763.9	(9.3)	164,754.6
01-Jun-20	174,023.8	(335.3)	(10,582.7)	163,105.8	(5.7)	163,100.1
01-Jun-21	174,713.0	0.0	(12,963.3)	161,749.7	(316.9)	161,432.8
01-Jun-22	150,465.2	0.0	(5,576.9)	144,888.3	(1,212.7)	143,675.6
01-Jun-23	150,143.9	0.0	(5,517.6)	144,626.3	(2,356.8)	142,269.5
01-Jun-24	154,117.9	0.0	(2,909.4)	151,208.5	0.0	151,208.5

Market Performance

Figure 5-5 shows cleared MW weighted average capacity market prices on a delivery year basis including base and incremental auctions for each delivery year, and the weighted average clearing prices by LDA in each Base Residual Auction for the entire history of the PJM capacity markets.

Table 5-17 shows RPM clearing prices for the 2021/2022 through 2024/2025 Delivery Years for all RPM auctions held through the first three months of 2024, and Table 5-18 shows the RPM cleared MW for the 2021/2022 through 2024/2025 Delivery Years for all RPM auctions held through the first three months of 2024.

Figure 5-6 shows the RPM cleared MW weighted average prices for each LDA from the 2021/2022 Delivery Year to the current delivery year, and all results for auctions for future delivery years that have been held through the first three months of 2024. A summary of these weighted average prices is given in Table 5-19.

Table 5-20 shows RPM revenue by delivery year for all RPM auctions held through the first three months of 2024 based on the unforced MW cleared and the resource clearing prices. For the 2022/2023 Delivery Year, RPM revenue was $4.0 billion. For the 2023/2024 Delivery Year, RPM revenue was $2.3 billion.

Table 5-21 shows RPM revenue by calendar year for all RPM auctions held through the first three months of 2024. In 2022, RPM revenue was $6.2 billion. In 2023, RPM revenue was $3.0 billion.

Table 5-22 shows the RPM annual charges to load. For the 2022/2023 Delivery Year, annual charges to load were $4.0 billion. For the 2023/2024 Delivery Year, annual charges to load are $2.2 billion.

Table 5-17 Capacity market clearing prices: 2021/2022 through 2024/2025 RPM Auctions

		RPM Clearing Price ($ per MW-day)													
	Product Type	RTO	MAAC	APS	PPL	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	PEPCO	ATSI	COMED	BGE	DUKE
2021/2022 BRA	Capacity Performance	$140.00	$140.00	$140.00	$140.00	$165.73	$140.00	$165.73	$204.29	$204.29	$140.00	$171.33	$195.55	$200.30	$140.00
2021/2022 First Incremental Auction	Capacity Performance	$23.00	$23.00	$23.00	$23.00	$25.00	$23.00	$25.00	$45.00	$219.00	$23.00	$23.00	$23.00	$60.00	$23.00
2021/2022 Second Incremental Auction	Capacity Performance	$10.26	$10.26	$10.26	$10.26	$15.37	$10.26	$15.37	$125.00	$125.00	$10.26	$10.26	$10.26	$70.00	$10.26
2021/2022 Third Incremental Auction	Capacity Performance	$20.55	$20.55	$20.55	$20.55	$26.36	$20.55	$26.36	$31.00	$31.00	$20.55	$20.55	$20.55	$39.00	$20.55
2022/2023 BRA	Capacity Performance	$50.09	$96.42	$50.09	$96.42	$97.75	$95.97	$97.75	$97.75	$97.75	$95.97	$50.09	$67.17	$107.92	$59.38
2022/2023 Third Incremental Auction	Capacity Performance	$50.05	$96.61	$50.05	$96.61	$97.93	$96.15	$97.93	$97.93	$97.93	$96.15	$50.05	$66.23	$108.22	$59.75
2023/2024 BRA	Capacity Performance	$34.13	$49.49	$34.13	$49.49	$49.49	$49.49	$69.95	$49.49	$49.49	$49.49	$34.13	$34.13	$69.95	$34.13
2023/2024 Third Incremental Auction	Capacity Performance	$37.53	$49.49	$37.53	$49.49	$146.03	$49.49	$146.03	$146.03	$146.03	$49.49	$37.53	$37.53	$79.03	$37.53
2024/2025 BRA	Capacity Performance	$28.92	$49.49	$28.92	$49.49	$54.95	$49.49	$90.64	$54.95	$54.95	$49.49	$28.92	$28.92	$73.00	$96.24
2024/2025 Third Incremental Auction	Capacity Performance	$53.52	$75.50	$53.52	$75.50	$221.23	$75.50	$221.23	$221.23	$221.23	$75.50	$53.52	$53.52	$153.76	$53.52

Table 5-18 Capacity market cleared MW: 2021/2022 through 2024/2025 RPM Auctions[159]

		UCAP (MW)													
Delivery Year	Auction	RTO	MAAC	APS	PPL	EMAAC	DPL South	PSEG	PSEG North	PEPCO	ATSI	COMED	BGE	DUKE	TOTAL
2021/2022	BASE	52,896.5	12,565.1	10,136.1	15,368.6	19,857.3	1,673.8	4,667.2	3,134.1	6,546.1	8,010.5	22,358.1	3,667.8	2,746.1	163,627.3
2021/2022	FIRST	194.1	200.4	45.9	27.2	119.0	15.3	18.3	79.1	207.9	739.3	360.4	48.7	87.6	2,143.2
2021/2022	SECOND	1,242.5	335.8	30.3	55.4	129.9	39.3	97.0	98.1	75.7	1,216.8	205.9	115.5	65.3	3,707.5
2021/2022	THIRD	1,638.4	168.7	231.6	127.8	911.0	18.3	227.7	244.8	67.2	942.7	221.7	275.9	159.2	5,235.0
2022/2023	BASE	37,732.2	12,804.7	10,147.4	14,118.7	23,658.8	1,305.3	1,914.3	2,531.1	3,621.8	10,550.7	19,223.7	4,750.9	2,117.7	144,477.3
2022/2023	THIRD	1,099.0	338.9	84.2	105.7	572.2	9.4	244.3	402.0	27.4	358.0	2,292.3	409.7	44.8	5,987.9
2023/2024	BASE	36,908.8	10,098.5	8,145.5	14,352.7	22,942.3	1,383.1	2,497.1	3,344.9	3,521.8	9,535.9	25,368.9	5,001.0	1,966.4	145,066.9
2023/2024	THIRD	315.7	1,786.4	395.0	79.3	671.0	24.2	32.4	43.8	15.3	355.8	1,050.0	240.0	68.4	5,077.0
2024/2025	BASE	37,406.8	10,855.5	8,874.0	14,184.9	23,151.1	1,444.7	2,665.3	3,494.3	3,433.8	9,720.6	25,156.1	5,056.5	2,062.1	147,505.6
2024/2025	THIRD	527.3	744.8	800.2	665.2	707.3	33.2	48.7	60.2	78.7	245.6	2,388.4	222.5	90.2	6,612.3

159 The MW values in this table refer to rest of LDA or RTO values, which are net of nested LDA values.

Table 5-19 Weighted average clearing prices by zone: 2021/2022 through 2024/2025

	Weighted Average Clearing Price ($ per MW-day)			
LDA	2021/2022	2022/2023	2023/2024	2024/2025
RTO				
AEP	$133.84	$49.35	$34.21	$29.62
APS	$133.84	$49.35	$34.21	$29.62
ATSI	$142.59	$48.89	$34.26	$29.67
Cleveland	$90.81	$49.41	$34.21	$28.92
COMED	$189.54	$63.70	$34.27	$31.05
DAY	$132.69	$49.16	$34.17	$29.10
DUKE	$127.66	$70.57	$34.24	$94.38
DUQ	$133.84	$49.35	$34.21	$29.62
DOM	$133.84	$49.35	$34.21	$29.62
EKPC	$133.84	$49.35	$34.21	$29.62
MAAC				
EMAAC				
ACEC	$158.72	$96.31	$52.21	$59.87
DPL	$158.72	$96.31	$52.21	$59.87
DPL South	$159.65	$97.41	$71.26	$93.57
JCPLC	$158.72	$96.31	$52.21	$59.87
PECO	$158.72	$96.31	$52.21	$59.87
PSEG	$184.82	$90.67	$50.71	$57.62
PSEG North	$190.48	$89.21	$50.73	$57.53
REC	$158.72	$96.31	$52.21	$59.87
SWMAAC				
BGE	$174.43	$119.73	$70.65	$77.79
PEPCO	$133.37	$94.75	$49.46	$50.02
WMAAC				
MEC	$134.56	$94.49	$49.49	$50.83
PE	$134.56	$94.49	$49.49	$50.83
PPL	$138.51	$95.29	$49.49	$50.93

Table 5-20 RPM revenue by delivery year: 2007/2008 through 2024/2025[160]

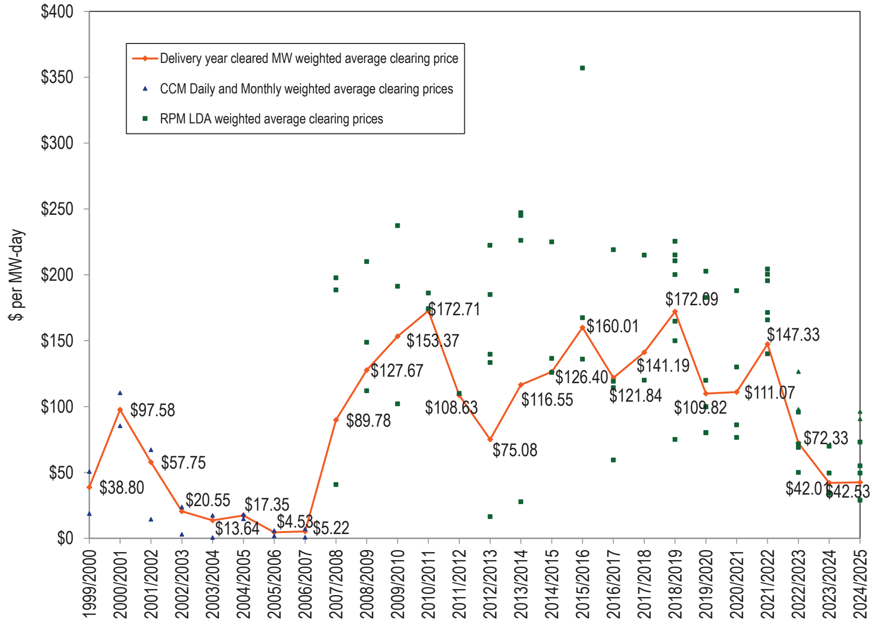
Delivery Year	Weighted Average RPM Price ($ per MW-day)	Weighted Average Cleared UCAP (MW)	Days	RPM Revenue
2007/2008	$89.78	129,409.2	366	$4,252,287,381
2008/2009	$127.67	130,629.8	365	$6,087,147,586
2009/2010	$153.37	134,030.2	365	$7,503,218,157
2010/2011	$172.71	134,036.2	365	$8,449,652,496
2011/2012	$108.63	134,182.6	366	$5,335,087,023
2012/2013	$75.08	141,283.9	365	$3,871,714,635
2013/2014	$116.55	159,844.5	365	$6,799,778,047
2014/2015	$126.40	161,205.0	365	$7,437,267,646
2015/2016	$160.01	173,519.4	366	$10,161,726,902
2016/2017	$121.84	179,749.0	365	$7,993,888,695
2017/2018	$141.19	180,590.5	365	$9,306,676,719
2018/2019	$172.09	175,996.0	365	$11,054,943,851
2019/2020	$109.82	177,064.2	366	$7,116,815,360
2020/2021	$111.07	173,688.5	365	$7,041,524,517
2021/2022	$147.33	174,713.0	365	$9,395,567,946
2022/2023	$72.33	150,465.2	365	$3,972,428,671
2023/2024	$42.01	150,143.9	366	$2,308,670,914
2024/2025	$42.53	154,117.9	365	$2,392,282,294

Table 5-21 RPM revenue by calendar year: 2007 through 2025[161]

Year	Weighted Average RPM Price ($ per MW-day)	Weighted Average Cleared UCAP (MW)	Effective Days	RPM Revenue
2007	$89.78	75,665.5	214	$2,486,310,108
2008	$111.93	130,332.1	366	$5,334,880,241
2009	$142.74	132,623.5	365	$6,917,391,702
2010	$164.71	134,033.7	365	$8,058,113,907
2011	$135.14	133,907.1	365	$6,615,032,130
2012	$89.01	138,561.1	366	$4,485,656,150
2013	$99.39	152,166.0	365	$5,588,442,225
2014	$122.32	160,642.2	365	$7,173,539,072
2015	$146.10	168,147.0	365	$9,018,343,604
2016	$137.69	177,449.8	366	$8,906,998,628
2017	$133.19	180,242.4	365	$8,763,578,112
2018	$159.31	177,896.7	365	$10,331,688,133
2019	$135.58	176,338.6	365	$8,734,613,179
2020	$110.55	175,368.7	366	$7,084,072,778
2021	$132.33	174,289.2	365	$8,421,703,404
2022	$103.36	160,496.5	365	$6,215,973,960
2023	$54.56	150,036.3	365	$2,993,266,921
2024	$42.31	152,714.4	366	$2,361,390,678
2025	$42.53	63,758.4	151	$989,683,908

160 The results for the ATSI Integration Auctions are not included in this table.
161 The results for the ATSI Integration Auctions are not included in this table.

Figure 5-5 History of capacity prices: 1999/2000 through 2024/2025[162]



162 The 1999/2000 through 2006/2007 capacity prices are CCM combined market, weighted average prices. The 2007/2008 through 2024/2025 capacity prices are RPM weighted average prices. The CCM data points plotted are cleared MW weighted average prices for the daily and monthly markets by delivery year. The RPM data points plotted are RPM LDA clearing prices. For the 2014/2015 and subsequent delivery years, only the prices for Annual Resources or Capacity Performance Resources are plotted.

Figure 5-6 Map of RPM capacity prices: 2021/2022 through 2024/2025

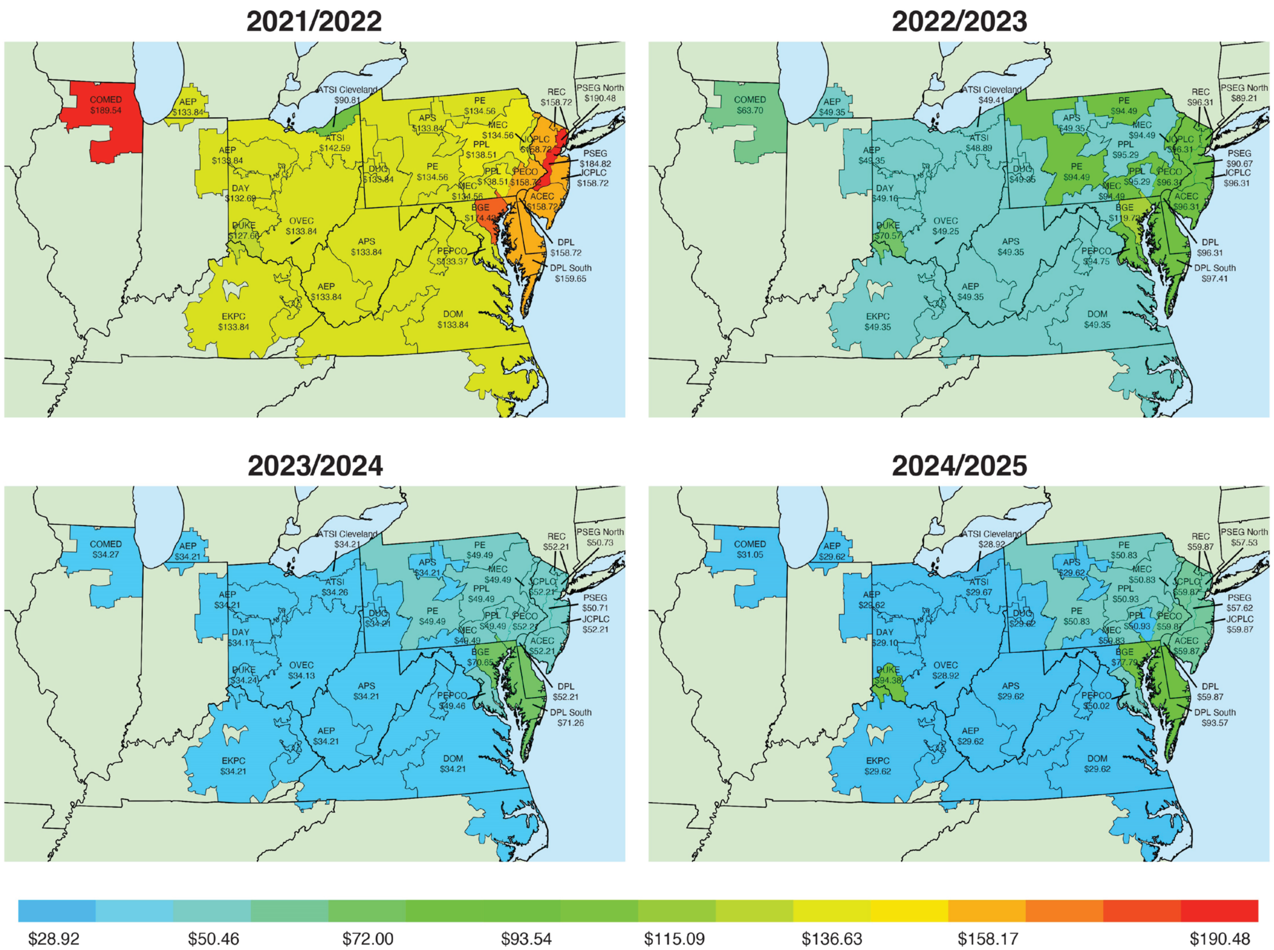


Table 5-22 RPM cost to load: 2022/2023 through 2024/2025 RPM Auctions[163 164 165]

	Net Load Price ($ per MW-day)	UCAP Obligation (MW)	Annual Charges
2022/2023			
Rest of RTO	$50.05	50,750.7	$927,101,691
EMAAC	$97.93	35,388.1	$1,264,867,389
WMAAC	$96.61	15,072.2	$531,498,382
BGE	$108.22	7,457.7	$294,575,131
COMED	$66.23	24,064.5	$581,774,443
DEOK	$59.75	5,090.6	$111,011,442
PEPCO	$96.15	6,870.5	$241,111,291
Total		144,694.3	$3,951,939,768
2023/2024			
Rest of RTO	$34.18	78,896.5	$986,982,057
EMAAC	$50.96	30,972.7	$577,657,195
WMAAC	$49.58	22,401.9	$406,535,572
Rest of EMAAC	$57.19	4,375.0	$91,582,753
BGE	$59.38	7,496.6	$162,936,916
Total		144,142.8	$2,225,694,492
2024/2025			
Rest of RTO	$29.40	77,303.0	$829,412,363
EMAAC	$58.23	32,230.4	$684,994,217
WMAAC	$50.11	22,843.9	$417,794,566
Rest of EMAAC	$69.42	4,584.4	$116,166,049
BGE	$61.53	7,716.5	$173,302,830
DEOK	$57.86	5,247.9	$110,826,582
Total		149,926.1	$2,332,496,607

FRR

The states have authority over their generation resources and can choose to remain in PJM capacity markets or to create FRR entities. The existing FRR approach remains an option for utilities with regulated revenues based on cost of service rates, including both privately and publicly owned (including public power entities and electric cooperatives) utilities. Such regulated utilities have had and continue to have the ability to opt out of the capacity market and provide their own capacity. The existing FRR rules were created in 2007 primarily for the specific circumstances of AEP as part of the original RPM capacity market design settlement. The MMU recommends that the FRR rules be revised and updated to ensure that the rules reflect current market realities and that FRR entities do not unfairly take advantage of those customers paying for capacity in the PJM Capacity Market.

The MMU has prepared reports with analysis of the potential impacts on states pursuing the FRR option. In separate reports for Illinois, Maryland, New Jersey, Ohio, Virginia, and the District of Columbia, the cost impacts of the state choosing the FRR option are computed under different FRR capacity price assumptions and different assumptions regarding the composition of the FRR service area.[166 167 168 169 170 171] The reports showed that the FRR approach is likely to lead to significant increases in payments by customers if it were to replace participation in the PJM markets. The impact on the remaining PJM capacity market footprint is also computed for each scenario. In all but a few scenarios the MMU finds that the FRR leads to higher costs for load included in the FRR service area. In all scenarios the MMU finds that prices in what remains of the PJM Capacity Market would be significantly lower.

Both FERC and the states have significant and overlapping authority affecting wholesale power markets. While the FERC MOPR approach was designed to ensure that subsidies did not affect the wholesale power markets, the states have ultimate authority over the generation choices made in the states. The FRR explorations by multiple states illustrated a possible path forward. Under that path, the FERC regulated markets would be unaffected by subsidies but many states would withdraw from the FERC regulated markets and create higher cost nonmarket solutions rather than be limited by MOPR. That would

163 The RPM annual charges are calculated using the rounded, net load prices as posted in the PJM RPM auction results.

164 There is no separate obligation for DPL South as the DPL South LDA is completely contained within the DPL Zone. There is no separate obligation for PSEG North as the PSEG North LDA is completely contained within the PSEG Zone. There is no separate obligation for ATSI Cleveland as the ATSI Cleveland LDA is completely contained within the ATSI Zone.

165 The net load prices and obligation MW for 2024/2025 are not final.

166 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of a ComEd FRR," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Potential_Impacts_of_the_Creation_of_a_ComEd_FRR_20191218.pdf> (December 18, 2020).

167 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of Maryland FRRs," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_Maryland_FRRs_20200416.pdf> (April 16, 2020).

168 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of New Jersey FRRs," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_New_Jersey_FRRS_20200513.pdf> (May 13, 2020).

169 *In the Matter of the Investigation of Resource Adequacy Alternatives*, New Jersey Board of Public Utilities, Docket No. EO20030203. Monitoring Analytics, LLC Comments, <http://www.monitoringanalytics.com/filings/2020/IMM_Comments_Docket_No_EO20030203_20200520.pdf> (May 20, 2020). Monitoring Analytics, LLC, Reply Comments <http://www.monitoringanalytics.com/filings/2020/IMM_Reply_Comments_Docket_No_EO20030203_20200624.pdf>. (June 24, 2020). Monitoring Analytics, Answer to Exelon and PSEG, <http://www.monitoringanalytics.com/filings/2020/IMM_Answer_to_Exelon_PSEG_Docket_No_EO20030203_20200715.pdf> (July 15, 2020).

170 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of Ohio FRRs," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of%20Ohio_FRRs_20200717.pdf> (July 17, 2020).

171 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of Virginia FRRs," <https://www.monitoringanalytics.com/reports/Reports/2021/IMM_VA_FRR_Report_20210518.pdf> (May 18, 2021).

not be an efficient outcome and would not serve the interests of customers or generators.

With the elimination of the current MOPR rules, the capacity market design must accommodate the choices made by states to subsidize renewable resources in a way that maximizes the role of competition to ensure that customers pay the lowest amount possible, consistent with state goals and the costs of providing the desired resources. Such an approach can take several forms, but none require the dismantling of the PJM capacity market design. The PJM capacity market design can adapt to a wide range of state supported resources and state programs. As a simple starting point, states can continue to support selected resources using a range of payment structures and those resources could participate in the capacity auctions. As a broader and more comprehensive option, PJM could create a central PJM RECs market to facilitate the competitive sale and purchase of RECs.

CRF Issue[172]

As a result of the significant changes to the federal tax code in December 2017, the capital recovery factor (CRF) tables in PJM OATT Attachment DD § 6.8(a) and Schedule 6A were not correct. These tables should have been updated in 2018. Correct CRFs ensure that offer caps and offer floors in the capacity market are correct. On May 4, 2021, PJM filed updates to the OATT under FPA Section 205.[173] In the filing, PJM proposed new CRFs based on the new tax law and new financial assumptions. The new financial assumptions are identical to the assumptions used in the PJM quadrennial review for the calculation of the cost of new entry (CONE) for the PJM reference resource. The MMU, in comments to the Commission, asked that the following formula be included in the tariff as an efficient alternative to use of tables which require updates whenever tax laws or financial assumptions change:[174] [175]

$$\mathrm{CRF} = \frac{r(1+r)^N\left[1 - \frac{sB}{\sqrt{1+r}} - s(1-B)\sqrt{1+r}\sum_{j=1}^{L}\frac{\mathrm{m_j}}{(1+\mathrm{r})^{\mathrm{j}}}\right]}{(1-s)\sqrt{1+\mathrm{r}}\,[(1+r)^N - 1]}$$

The MMU also proposed that PJM discontinue the practice of using an average state tax rate in the CRF calculation. The CRF formula allows for the quick and efficient calculation of a unit's CRF using the state tax rate that is applicable to a specific unit.

FERC accepted PJM's filing but also required that the CRF formula be included in the tariff.[176] FERC rejected the MMU's unit specific state tax recommendation. Going forward, PJM will post the CRFs on their website. Table 5-24 shows the CRFs that are currently posted. The values in Table 5-24 were calculated using the formula above and the financial assumptions in Table 5-25. Bonus depreciation assumptions vary by delivery year with 100 percent bonus depreciation assumed in the 2022/2023 Delivery Year. The bonus depreciation in each subsequent delivery year is reduced by 20 percent.

Table 5-23 Variable descriptions for the CRF formula

Formula Symbol	Description
r	After tax weighted average cost of capital (ATWACC)
s	Effective tax rate
B	Bonus depreciation percent
N	Cost Recovery Period (years)
L	Lesser of N or 16 (years)
mj	Modified Accelerated Cost Recovery System (MACRS) depreciation factor for year j = 1, ..., 16

The MMU supports the changes to the tariff to correct the application of CRF to the capacity market but there are still unresolved issues. The tariff revisions lack clarity about how CRF values will be determined in the future and to which projects they apply, and lack clarity about how CRF values would be applied to APIR for project costs that are currently being recovered. For

172 See related filing on CRF issue in black start: Comments of the Independent Market Monitor for PJM, Docket No. ER21-1635 (April 28, 2021).
173 "Revisions to Capital Recovery Factor for Avoidable Project Investment Cost Determinations and Request for Waiver of Sixty-Day Notice Requirement," PJM Interconnection L.L.C., Docket No. ER21-1844-000 (May 4, 2021).
174 See "Comments of the Independent Market Monitor for PJM," Docket No. ER21-1844-000 (May 25, 2021).
175 The formula was first introduced in a related Section 205 filing regarding CRFs for black start service. See "Comments of the Independent Market Monitor for PJM" (April 28, 2021) and "Answer and Motion to Answer of the Independent Market Monitor for PJM" (May 19, 2021) in Docket No. ER21-1635-000.
176 Order 176 FERC ¶61,003 (July 2, 2021).

example, Table 5-24, which is identical to the table posted by PJM, includes CRF values for projects that go into service for four identified delivery years but fails to note that these CRF values for a later delivery year would not apply for investments made in prior delivery years that will still be in service in the later delivery year.[177] For example, a project that can use the depreciation provisions relevant for the 2023/2024 Delivery Year uses the depreciation provisions once and those provisions affect the project's CRF for its entire life, regardless of the CRF values in the table for subsequent delivery years. However, changes in the tax rate apply each year and if the tax rate changes the applicable CRF values would change for all projects, regardless of vintage. As a result, the CRF values in Table 5-24 for delivery years after 2023/2024 would not apply to the calculation of APIR values for projects that go into service for the 2023/2024 Delivery Year. A similar issue exist for projects that were assigned a CRF under the previous tariff rules. The change in the tax rate should be reflected in the CRF going forward. PJM does not plan to do this and the Commission stated that the issue is beyond the scope of the PJM filing.[178]

Table 5-24 Levelized CRF values: 2023/2024 Delivery Year through 2026/2027 Delivery Year

Age of Existing Units (Years)	Remaining Life of Plant	Levelized CRF 2023/2024	Levelized CRF 2024/2025	Levelized CRF 2025/2026	Levelized CRF 2026/2027
1 to 5	30	0.091	0.094	0.096	0.099
6 to 10	25	0.096	0.098	0.101	0.104
11 to 15	20	0.104	0.107	0.110	0.113
16 to 20	15	0.119	0.122	0.126	0.129
21 to 25	10	0.152	0.158	0.164	0.169
25 Plus	5	0.258	0.271	0.283	0.296
Mandatory CapEx	4	0.312	0.328	0.345	0.361
40 Plus Alternative	1	1.100	1.100	1.100	1.100

Table 5-25 Financial parameter and tax rate assumptions for CRF calculations

Financial Parameter	Parameter Value
Equity Funding Percent	45.000%
Debt Funding Percent	55.000%
Equity Rate	13.000%
Debt Interest Rate	6.000%
Federal Tax Rate	21.000%
State Tax Rate	9.300%
Effective Tax Rate	28.347%
After tax Weighted Average Cost of Capital	8.215%

The 2021 update to the CRF values was calculated using the weighted average cost of capital (WACC) model. The original CRF values, prior to 2021, were calculated using a flow to equity (FTE) model. The WACC model assumes a constant debt to equity ratio during the capital recovery period and therefore assumes that debt holders are paid more quickly than is required. The FTE model recognizes that the debt is repaid according to a predetermined payment schedule with all revenue in excess of taxes and debt payments going to the equity investor. The FTE model accurately reflects the cash flows that occur during capital recovery. Table 5-26 compares CRFs calculated under the two approaches using the assumptions in Table 5-25. The difference between the WACC CRF and FTE CRF is dependent upon the capital recovery term and the level of bonus depreciation. The WACC CRF exceeds the FTE CRF by 16.4 percent under 100 percent bonus depreciation with a 30 year cost recovery term. The FTE model is the correct approach because it accurately captures the cash flows during capital recovery over the defined financial life of the asset.

177 See "Capital Recovery Factors ("CRF") for Avoidable Project Investment Cost ("APIR") Determinations," <https://pjm.com/-/media/markets-ops/rpm/rpm-auction-info/crf-values-for-apir-determination.ashx>.
178 Order 176 FERC ¶61,003 (July 2, 2021) at 28.

Table 5-26 Comparison of FTE and WACC CRFs

Capital Recovery Term (years)	WACC CRF						FTE CRF					
	Bonus Percent						Bonus Percent					
	100%	80%	60%	40%	20%	0%	100%	80%	60%	40%	20%	0%
4	0.296	0.312	0.328	0.345	0.361	0.377	0.289	0.307	0.324	0.342	0.360	0.377
5	0.246	0.258	0.271	0.283	0.296	0.308	0.238	0.252	0.266	0.280	0.294	0.308
10	0.147	0.152	0.158	0.164	0.169	0.175	0.138	0.145	0.153	0.160	0.168	0.175
15	0.116	0.119	0.122	0.126	0.129	0.132	0.105	0.111	0.116	0.122	0.127	0.133
20	0.101	0.104	0.107	0.110	0.113	0.115	0.090	0.095	0.100	0.105	0.110	0.115
25	0.093	0.096	0.098	0.101	0.104	0.106	0.081	0.086	0.091	0.096	0.100	0.105
30	0.088	0.091	0.094	0.096	0.099	0.101	0.076	0.081	0.085	0.090	0.095	0.099
Capital Recovery Term (years)	Absolute Change (WACC CRF less FTE CRF)						Relative Change					
	Bonus Percent						Bonus Percent					
	100%	80%	60%	40%	20%	0%	100%	80%	60%	40%	20%	0%
4	0.007	0.005	0.004	0.003	0.001	0.000	2.3%	1.8%	1.2%	0.8%	0.3%	(0.1%)
5	0.007	0.006	0.004	0.003	0.001	0.000	3.1%	2.3%	1.6%	1.0%	0.4%	(0.1%)
10	0.009	0.007	0.005	0.003	0.002	0.000	6.5%	4.9%	3.4%	2.1%	0.9%	(0.2%)
15	0.010	0.008	0.006	0.004	0.002	0.000	9.5%	7.2%	5.0%	3.1%	1.3%	(0.3%)
20	0.011	0.009	0.007	0.005	0.003	0.000	12.2%	9.3%	6.7%	4.4%	2.3%	0.4%
25	0.012	0.010	0.007	0.005	0.003	0.001	14.4%	11.2%	8.2%	5.6%	3.2%	1.1%
30	0.012	0.010	0.008	0.006	0.004	0.002	16.4%	12.8%	9.6%	6.7%	4.1%	1.7%

Timing of Unit Retirements

Generation owners that want to deactivate a unit, either to mothball or permanently retire, must provide notice to PJM and the MMU prior to the proposed deactivation date. Prior to September 2022, generation owners were required to provide deactivation notices at least 90 days before the proposed deactivation date. Beginning in September 2022, PJM and the MMU began reviewing deactivation requests quarterly, and the desired deactivation date is now based on the quarter the request was submitted (Table 5-27). The result is no change to the effective period between the notice and the retirement, if notice is provided on the last day of the submittal period, and an increase to six months notice, if notice is given on the first day of the submittal period.

Table 5-27 Earliest deactivation dates allowed based on quarterly submission

Date Request Submitted	Earliest Deactivation Date Permitted
January 1 to March 31	July 1
April 1 to June 30	October 1
July 1 to September 30	January 1 (following calendar year)
October 1 to December 31	April 1 (following clendar year)

Generation owners seeking a capacity market must offer exemption for a delivery year must submit their deactivation request no later than the December 1 preceding the Base Residual Auction or 120 days before the start of an Incremental Auction for that delivery year.[179] If no reliability issues are found during PJM's analysis of the retirement's impact on the transmission system, and the MMU finds no market power issues associated with the proposed deactivation, the unit may deactivate at any time thereafter.[180]

Table 5-28 shows the timing of actual deactivation dates and the initially requested deactivation date, for all deactivation requests submitted from January 2018 through March 2024. Of the 171 deactivation requests submitted, 31 units (18.1 percent) deactivated an average of 157 days earlier than their initially requested date; 29 units (17.0 percent) deactivated an average of 106 days later than the originally requested deactivation date; and 67 units (39.2 percent) deactivated on their initially requested date. Nineteen (11.1 percent) of the unit deactivations were cancelled an average of 272 days before their scheduled deactivation date, and 25 (14.6 percent) of the unit deactivations have not yet reached their target retirement date. Table 5-29 shows this information broken out by fuel types.

Table 5-28 Timing of actual unit deactivations compared to requested deactivation date: Requests submitted January 2018 through March 2024

Status	Number of Units	Percent	Average Days Deviation from Originally Requested Date
Early	31	18.1%	(157)
Late	29	17.0%	106
On time	67	39.2%	0
Cancelled	19	11.1%	(272)
Pending	25	14.6%	-
Total	171	100.0%	-

179 OATT Attachment DD § 6.6(g).
180 OATT Part V §113.

Table 5-29 Timing of actual unit deactivations compared to requested deactivation date by fuel type: Requests submitted January 2018 through March 2024

Fuel Type	Status	Number of Units	Percent	Average Days Deviation from Originally Requested Date
Biomass	Early	2	66.7%	(4)
	Late	0	0.0%	-
	On time	0	0.0%	-
	Cancelled	0	0.0%	-
	Pending	1	33.3%	-
Total		3	100.0%	-
Coal	Early	15	31.3%	(169)
	Late	9	18.8%	78
	On time	15	31.3%	0
	Cancelled	4	8.3%	(371)
	Pending	5	10.4%	-
Total		48	100.0%	-
Diesel	Early	0	0.0%	-
	Late	0	0.0%	-
	On time	5	83.3%	-
	Cancelled	0	0.0%	-
	Pending	1	16.7%	-
Total		6	100.0%	-
Methane	Early	4	16.0%	(107)
	Late	7	28.0%	71
	On time	11	44.0%	0
	Cancelled	2	8.0%	(190)
	Pending	1	4.0%	-
Total		25	100.0%	-
Natural Gas	Early	4	14.3%	(197)
	Late	6	21.4%	94
	On time	9	32.1%	0
	Cancelled	1	3.6%	-
	Pending	8	28.6%	-
Total		28	100.0%	-
Nuclear	Early	0	0.0%	-
	Late	0	0.0%	-
	On time	0	0.0%	-
	Cancelled	10	100.0%	(312)
	Pending	0	0.0%	-
Total		10	100.0%	-
Oil	Early	3	7.1%	(218)
	Late	7	16.7%	188
	On time	22	52.4%	0
	Cancelled	1	2.4%	(105)
	Pending	9	21.4%	-
Total		42	100.0%	-
Solid Waste	Early	0	0.0%	-
	Late	0	0.0%	-
	On time	1	100.0%	0
	Cancelled	0	0.0%	-
	Pending	0	0.0%	-
Total		1	100.0%	-
Storage	Early	3	37.5%	-
	Late	0	0.0%	-
	On time	4	50.0%	0
	Cancelled	1	12.5%	-
	Pending	0	0.0%	-
Total		8	100.0%	-

Part V Reliability Service

PJM must make out of market payments to units that want to retire (deactivate) but that PJM requires to remain in service, for limited operation, for a defined period because the unit is needed for reliability.[181] This provision has been known as Reliability Must Run (RMR) service but RMR is not defined in the PJM tariff. Here the term Part V reliability service is used. The need to retain uneconomic units in service reflects a flawed market design and/or planning process problems. It is essential that the deactivation provisions of the tariff be evaluated and modified. The current approach to RMR service tends to suppress locational capacity market prices and provide the wrong price signal for either investing in the existing resource or investing in new resources to provide locational reliability.

To address that issue, the MMU recommends that the same reliability standard be used in capacity auctions as is used by PJM transmission planning. One result of the current design is that a unit may fail to clear in a BRA, decide to retire as a result, but then be found to be needed for reliability by PJM planning and paid under Part V of the OATT (RMR) to remain in service while transmission upgrades are made.

If a unit is needed for reliability, the market should reflect a locational value consistent with that need which would result in the unit remaining in service or being replaced by a competitor unit. To address that issue, the MMU recommends that units that are paid under Part V of the OATT (RMR) not be included in the calculation of CETO or reliability in the relevant LDA, in order to ensure that the capacity market price signal reflects the appropriate supply and demand conditions.

The planning process should, to the extent possible, evaluate the impact of the loss of units at risk and determine in advance whether transmission upgrades are required.[182] It is essential that PJM look forward and attempt to plan for foreseeable unit retirements, whether for economic or regulatory reasons. While not all retirements are completely foreseeable, improvement is needed in the process for ensuring that planning is looking at the probability of retirements, especially of resources that are critical to locational reliability in order to minimize the duration of any RMR requirement.

The actual implementation of Part V provision of the tariff has resulted in overpayment of the RMR resources. It is essential that the compensation provisions of Part V of the tariff be modified to ensure payment of all but only the actual costs incurred by the generation owner to provide the service, plus an incentive.

When notified of an intended deactivation, the MMU performs a market power study to ensure that the deactivation is economic, not an exercise of market power through withholding, and consistent with competition.[183] PJM performs a system study to determine whether the system can accommodate the deactivation on the desired date, and if not, when it could.[184] If PJM determines that it needs a unit for a period beyond the intended deactivation date, PJM will request a unit to remain in service, generally only as an option in the event the unit is needed for reliability.[185] The PJM market rules do not require an owner to remain in service, but owners must provide advance notice of a proposed deactivation (See Table 5-27).[186] The owner of a generation capacity resource must provide notice of a proposed deactivation in order to avoid a requirement to offer in RPM auctions.[187] In order to avoid submitting an offer for a unit in the next three-year forward RPM base residual auction, an owner must show "a documented plan in place to retire the resource," including a notice of deactivation filed with PJM, 120 days prior to such auction.[188]

Under the current rules, a unit remaining in service at PJM's request can recover its costs of continuing to operate under either the deactivation avoidable cost rate (DACR), which is a formula rate, or the cost of service

181 OATT Part V §114.

182 *See, e.g.*, 140 FERC ¶ 61,237 at P 36 (2012) ("The evaluation of alternatives to an SSR designation is an important step that deserves the full consideration of MISO and its stakeholders to ensure that SSR Agreements are used only as a 'limited, last-resort measure.'"); 118 FERC ¶ 61,243 at P 41 (2007) ("the market participants that pay for the agreements pay out-of-market prices for the service provided under the RMR agreements, which broadly hinders market development and performance.[footnote omitted] As a result of these factors, we have concluded that RMR agreements should be used as a last resort."); 110 FERC ¶ 61,315 at P 40 (2005) ("The Commission has stated on several occasions that it shares the concerns . . . that RMR agreements not proliferate as an alternative pricing option for generators, and that they are used strictly as a last resort so that units needed for reliability receive reasonable compensation.").

183 OATT § 113.2; OATT Attachment M § IV.1.

184 OATT § 113.2.

185 *Id.*

186 OATT § 113.1.

187 OATT Attachment DD § 6.6(g).

188 *Id.*

recovery rate. The deactivation avoidable cost rate is designed to permit the recovery of the costs of the unit's "continued operation," termed "avoidable costs," plus an incentive adder.[189] Avoidable costs are defined to mean "incremental expenses directly required for the operation of a generating unit." [190] The incentives escalate for each year of service (first year, 10 percent; second year, 20 percent; third year, 35 percent; fourth year, 50 percent).[191] The rules provide terms for the repayment of project investment by owners of units that choose to keep units in service after the defined period ends.[192] Project investment is capped at $2 million, above which FERC approval is required.[193] The cost of service rate is designed to permit the recovery of the unit's "cost of service rate to recover the entire cost of operating the generating unit" if the generation owner files a separate rate schedule at FERC.[194]

The DACR is unnecessarily prescriptive about the nature of the incremental costs needed to provide service, includes unsupported escalation to extremely high incentive rates, and unnecessarily caps incremental investment at an arbitrary level.

Table 5-30 shows units that have provided Part V reliability service to PJM, including the Indian River 4 unit, which began providing RMR service on June 1, 2022. Only two of nine owners have used the deactivation avoidable cost rate approach. The other seven owners used the cost of service recovery rate. For units using the cost of service recovery rate option, revenues have averaged about 4.1 times the corresponding market price of capacity while for units using the deactivation avoidable cost rate, revenues have averaged about 1.6 times the corresponding market price of capacity.[195]

Table 5-30 Part V reliability service summary

Unit Names	Owner	Fuel Type	ICAP (MW)	Cost Recovery Method	Docket Numbers	Start of Term	End of Term
Brandon Shores 1	Talen Energy Corporation	Coal	635.0	Cost of Service Recovery Rate	ER24-1790	01-Jun-25	31-Dec-28
Brandon Shores 2	Talen Energy Corporation	Coal	638.0	Cost of Service Recovery Rate	ER24-1790	01-Jun-25	31-Dec-28
Wagner 3	Talen Energy Corporation	Coal	305.0	Cost of Service Recovery Rate	ER24-1787	01-Jun-25	31-Dec-28
Wagner 4	Talen Energy Corporation	Oil	397.0	Cost of Service Recovery Rate	ER24-1787	01-Jun-25	31-Dec-28
Indian River 4	NRG Power Marketing LLC	Coal	410.0	Cost of Service Recovery Rate	ER22-1539	01-Jun-22	31-Dec-26
B.L. England 2	RC Cape May Holdings, LLC	Coal	150.0	Cost of Service Recovery Rate	ER17-1083	01-May-17	01-May-19
Yorktown 1	Dominion Virginia Power	Coal	159.0	Deactivation Avoidable Cost Rate	ER17-750	06-Jan-17	13-Mar-18
Yorktown 2	Dominion Virginia Power	Coal	164.0	Deactivation Avoidable Cost Rate	ER17-750	06-Jan-17	13-Mar-18
B.L. England 3	RC Cape May Holdings, LLC	Oil	148.0	Cost of Service Recovery Rate	ER17-1083	01-May-17	24-Jan-18
Ashtabula	FirstEnergy Service Company	Coal	210.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	11-Apr-15
Eastlake 1	FirstEnergy Service Company	Coal	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Eastlake 2	FirstEnergy Service Company	Coal	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Eastlake 3	FirstEnergy Service Company	Coal	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Lakeshore	FirstEnergy Service Company	Coal	190.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Elrama 4	GenOn Power Midwest, LP	Coal	171.0	Cost of Service Recovery Rate	ER12-1901	01-Jun-12	01-Oct-12
Niles 1	GenOn Power Midwest, LP	Coal	109.0	Cost of Service Recovery Rate	ER12-1901	01-Jun-12	01-Oct-12
Cromby 2 and Diesel	Exelon Generation Company, LLC	Natural gas/oil, Diesel	203.7	Cost of Service Recovery Rate	ER10-1418	01-Jun-11	01-Jan-12
Eddystone 2	Exelon Generation Company, LLC	Coal	309.0	Cost of Service Recovery Rate	ER10-1418	01-Jun-11	01-Jun-12
Brunot Island CT2A, CT2B, CT3 and CC4	Orion Power MidWest, L.P.	Natural gas	244.0	Cost of Service Recovery Rate	ER06-993	16-May-06	05-Jul-07
Hudson 1	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	Natural gas	355.0	Cost of Service Recovery Rate	ER05-644, ER11-2688	25-Feb-05	08-Dec-11
Sewaren 1-4	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	Natural gas	453.0	Cost of Service Recovery Rate	ER05-644	25-Feb-05	01-Sep-08

189 OATT § 114 (Deactivation Avoidable Credit = ((Deactivation Avoidable Cost Rate + Applicable Adder) * MW capability of the unit * Number of days in the month) – Actual Net Revenues).
190 OATT § 115.
191 *Id.*
192 OATT § 118.
193 OATT §§ 115, 117.
194 OATT § 119.
195 The final rate for the Indian River 4 has not been established. The final rate could be lower or higher. The rate in the table is the actual cost to date of the RMR service. The final rates for Brandon Shores and Wagner have not been established. RMR service for these plants has not started.

Table 5-31 Part V reliability service cost summary

		Initial Filing		Actual		Weighted Average
Unit Names	Owner	Total Cost	Cost per MW-day	Total Cost	Cost per MW-day	RPM Clearing Price ($ per MW-day)
Brandon Shores 1	Talen Energy Corporation	$327,039,342	$393.45	NA	NA	NA
Brandon Shores 2	Talen Energy Corporation	$328,584,409	$393.45	NA	NA	NA
Wagner 3	Talen Energy Corporation	$64,791,528	$162.29	NA	NA	NA
Wagner 4	Talen Energy Corporation	$84,335,202	$162.29	NA	NA	NA
Indian River 4	NRG Power Marketing LLC	$357,065,662	$520.25	$145,896,740	$556.88	$52.28
B.L. England 2	RC Cape May Holdings, LLC	$35,953,561	$328.34	$51,779,892	$472.88	$154.51
Yorktown 1	Dominion Virginia Power	$9,739,434	$142.12	$8,427,011	$122.97	$134.64
Yorktown 2	Dominion Virginia Power	$10,045,705	$142.12	$9,529,149	$134.81	$134.64
B.L. England 3	RC Cape May Holdings, LLC	$28,710,481	$723.84	$10,058,665	$253.60	$138.95
Ashtabula	FirstEnergy Service Company	$35,236,541	$176.25	$25,177,042	$125.94	$107.91
Eastlake 1	FirstEnergy Service Company	$20,842,416	$257.01	$18,484,399	$227.93	$102.73
Eastlake 2	FirstEnergy Service Company	$20,182,025	$248.87	$17,683,994	$218.06	$102.73
Eastlake 3	FirstEnergy Service Company	$20,192,938	$249.00	$17,391,797	$214.46	$102.73
Lakeshore	FirstEnergy Service Company	$33,993,468	$240.47	$20,532,969	$145.25	$102.73
Elrama 4	GenOn Power Midwest, LP	$15,435,472	$739.88	$7,576,435	$363.17	$75.08
Niles 1	GenOn Power Midwest, LP	$9,510,580	$715.19	$4,829,423	$363.17	$75.08
Cromby 2 and Diesel	Exelon Generation Company, LLC	$20,213,406	$463.70	$17,776,658	$407.80	$108.63
Eddystone 2	Exelon Generation Company, LLC	$165,993,135	$1,467.74	$85,364,570	$754.81	$108.63
Brunot Island CT2A, CT2B, CT3 and CC4	Orion Power MidWest, L.P.	$60,933,986	$601.76	$23,507,795	$232.15	$89.78
Hudson 1	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	$28,934,341	$32.90	$62,364,359	$70.92	$132.72
Sewaren 1-4	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	$47,633,115	$81.89	$79,580,435	$136.82	$97.39

In each of the cost of service recovery rate filings for Part V reliability service, the scope of recovery permitted under the cost of service approach defined in Section 119 has been a significant issue. Owners have sought to recover fixed costs, incurred prior to the noticed deactivation date, in addition to the cost of operating the generating unit. Owners have cited the cost of service reference to mean that the unit is entitled to file to recover costs that it was unable to recover in the competitive markets, in addition to recovery of costs of actually providing the Part V reliability service.

The cost of service recovery rate approach has been interpreted by the companies using that approach to allow the company to develop the type of rate case filing used by regulated utilities, using a test year with adjustments, to establish a rate base including investment in the existing plant and new investment necessary to remain in service and to earn a return on that rate base and receive depreciation of that rate base, plus guarantee recovery of estimated operation and maintenance expenses. Companies developing the cost of service recovery rate have ignored the tariff's limitation to the costs of operating the unit during the Part V reliability service period and have included costs incurred prior to the decision to deactivate and costs associated with closing the unit that would have been incurred regardless of the Part V reliability service period.[196] In some cases, the filing included costs that already had been written off, or impaired, on the company's public books.[197] [198] The requested cost of service recovery rates substantially exceed the actual costs of operating to provide the reliability required by PJM.

196 See, e.g., FERC Dockets Nos. ER10-1418-000, ER12-1901-000 and ER17-1083-000.
197 See GenOn Filing, Docket No. ER12-1901-000 (May 31, 2012) at Exh. No. GPM-1 at 9:16–21.
198 See NRG Filing, Docket No. ER22- 1539-000 (April 1, 2022).

Because such units are needed by PJM for reliability reasons, and the provision of the service is voluntary in PJM, owners of units that PJM needs to remain in service after the desired retirement date have significant market power in establishing the terms of this reliability service which have generally been set through settlements.

This reliability service should be provided to PJM customers at reasonable rates, which reflect the relatively low risk nature of providing such service to owners, the reliability need for such service and the opportunity for owners to be guaranteed recovery of 100 percent of the actual incremental costs required to operate to provide the service plus an incentive.

The MMU recommends elimination of both the cost of service recovery rate in OATT Section 119 and the deactivation avoidable cost rate in Part V, and their replacement with clear language that provides for the recovery of 100 percent of the actual incremental costs required to operate to provide the service plus an incentive.

The MMU recommends that units recover all and only the incremental costs, including incremental investment costs without a cap, required to provide Part V reliability service (RMR service) that the unit owner would not have incurred if the unit owner had deactivated its unit as it proposed, plus a defined incentive payment. Customers should bear no responsibility for paying previously incurred (sunk) costs, including a return on or of prior investments.

Generator Performance

Generator performance results from the interaction between the physical characteristics of the units and the level of expenditures made to maintain the capability of the units, which in turn is a function of incentives from energy, ancillary services and capacity markets. Generator performance indices include those based on total hours in a period (generator performance factors) and those based on hours when units are needed to operate by the system operator (generator forced outage rates).

Capacity Factor

Capacity factor measures the actual output of a power plant over a period of time compared to the potential output of the unit had it been running at full nameplate capacity for every hour during that period. Table 5-32 shows the capacity factors by unit type for the first three months of 2023 and 2024. In the first three months of 2024, nuclear units had a capacity factor of 97.0 percent, compared to 96.3 percent in the first three months of 2023; combined cycle units had a capacity factor of 69.1 percent in the first three months of 2024, compared to a capacity factor of 67.9 percent in the first three months of 2023; coal units had a capacity factor of 36.2 percent in the first three months of 2024, compared to 30.0 percent in the first three months of 2023.

Table 5-32 Capacity factor (By unit type (GWh)): January through March, 2023 and 2024[199 200 201]

	2023 (Jan-Mar)		2024 (Jan-Mar)		Change in 2024
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor	from 2023
Battery	6.0	1.0%	14.9	2.1%	1.0%
Combined Cycle	81,824.4	67.9%	86,947.5	69.1%	1.2%
Single Fuel	72,421.4	75.8%	75,523.4	74.9%	(0.9%)
Dual Fuel	9,403.0	37.5%	11,424.1	45.5%	8.0%
Combustion Turbine	2,137.0	3.3%	3,449.3	5.4%	2.1%
Single Fuel	1,513.6	3.6%	2,251.5	5.2%	1.6%
Dual Fuel	623.4	2.8%	1,197.8	6.0%	3.2%
Diesel	100.6	11.4%	48.6	7.5%	(3.9%)
Single Fuel	96.6	12.2%	44.1	7.7%	(4.5%)
Dual Fuel	4.0	4.5%	4.5	6.0%	1.5%
Diesel (Landfill gas)	267.5	46.0%	239.8	50.0%	4.0%
Fuel Cell	48.3	80.3%	53.6	89.7%	9.3%
Nuclear	67,873.9	96.3%	69,118.8	97.0%	0.7%
Pumped Storage Hydro	1,484.0	12.4%	1,775.8	15.7%	3.3%
Run of River Hydro	2,602.3	44.7%	2,954.9	63.2%	18.5%
Solar	1,898.7	15.7%	2,863.4	14.1%	(1.5%)
Steam	31,636.7	25.4%	32,459.1	31.7%	6.3%
Biomass	1,294.1	64.5%	1,329.6	68.8%	4.3%
Coal	29,083.2	30.0%	29,545.2	36.2%	6.2%
Single Fuel	29,083.2	32.3%	29,545.2	36.2%	4.0%
Dual Fuel	0.0	0.0%	0.0	0.0%	0.0%
Natural Gas	1,028.8	42.7%	1,314.9	46.0%	3.3%
Single Fuel	96.0	55.9%	107.2	56.0%	0.0%
Dual Fuel	932.7	16.4%	1,207.7	23.0%	6.5%
Oil	230.7	2.3%	269.4	3.5%	1.2%
Wind	9,928.5	39.8%	9,994.2	37.9%	(1.9%)
Total	199,808.0	45.7%	209,919.8	49.1%	3.4%

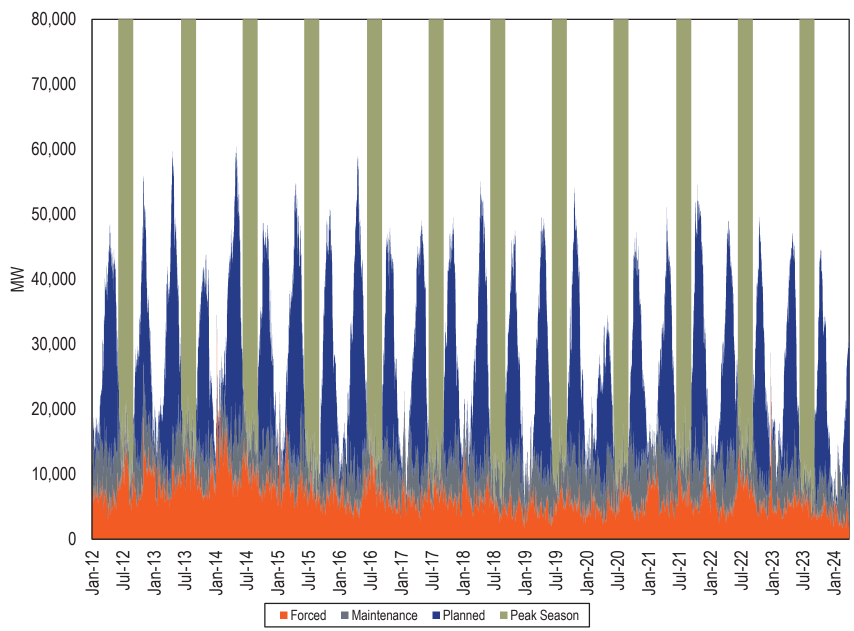
Generator Performance Factors

Generator outages fall into three categories: planned, maintenance, and forced. The scheduling of planned and maintenance outages must be approved by PJM. The approval may be withdrawn in order to maintain system reliability.[202] The PJM Market Rules do not specify any consequences if the planned outage continues after PJM withdraws approval. If PJM withdraws approval for a maintenance outage during the outage and the unit cannot operate, the outage is defined to be a forced outage.[203] Outages that are approved by PJM may be extended. An extension to a planned outage that enters the peak period is treated as a forced outage. A maintenance outage that is extended to more than nine days during the peak period is treated as a forced outage.

199 The capacity factors in this table are based on nameplate capacity values, and are calculated based on when the units come on line.
200 The subcategories of steam units are consolidated consistent with confidentiality rules. Coal is comprised of coal and waste coal. Natural gas is comprised of natural gas and propane. Oil is comprised of both heavy and light oil. Biomass is comprised of biomass, landfill gas, and municipal solid waste.
201 Hours in which batteries have net negative generation do not count toward their runtime.
202 "PJM Manual 10: Pre-Scheduling Operations," § 2.3.2 Maintenance Outage Rules, Rev. 40 (Dec. 15, 2021).
203 OATT, Attachment K (Appendix) § 1.9.3 (b).

The MW on outage vary during the year. For example, the MW on planned outage are generally highest in the spring and fall, as shown in Figure 5-7, as a result of restrictions on planned outages during the winter and summer. The Peak Period Maintenance Season, shown in Figure 5-7, runs from the weeks containing the twenty-fourth through thirty-sixth Wednesdays of the year. Planned outages cannot start in nor extend into this period. In 2024, the period runs from Monday, June 10 until Friday, September 6. The effect of the seasonal variation in outages can be seen in the monthly generator performance metrics in Figure 5-10.

Figure 5-7 Outages (MW): 2012 through March 2024



In the first three months of 2024, forced outages were 27.1 percent lower, planned outages were 0.4 percent lower, and maintenance outages were 29.4 percent lower than in the first three months of 2023.

Performance factors include the equivalent availability factor (EAF), the equivalent maintenance outage factor (EMOF), the equivalent planned outage factor (EPOF) and the equivalent forced outage factor (EFOF). These four factors add to 100 percent for any generating unit. The EAF is the proportion of hours in a year when a unit is available to generate at full capacity while the three outage factors include all the hours when a unit is unavailable. The EMOF is the proportion of hours in a year when a unit is unavailable because of maintenance outages and maintenance deratings. The EPOF is the proportion of hours in a year when a unit is unavailable because of planned outages and planned deratings. The EFOF is the proportion of hours in a year when a unit is unavailable because of forced outages and forced deratings.

The PJM aggregate EAF, EFOF, EPOF, and EMOF are shown in Figure 5-8. Metrics by unit type are shown in Table 5-33.

Figure 5-8 Equivalent outage and availability factors: January through March, 2007 to 2024

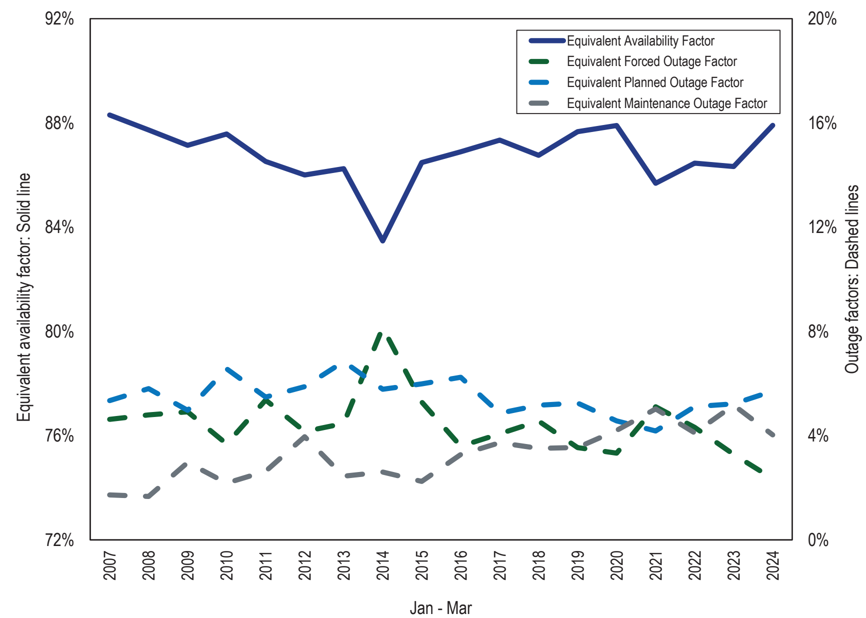


Table 5-33 EFOF, EPOF, EMOF and EAF by unit type: January through March, 2007 to 2024

	Coal				Combined Cycle				Combustion Turbine				Diesel			
Jan-Mar	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF
2007	7%	7%	2%	84%	2%	6%	1%	91%	6%	2%	3%	90%	8%	0%	2%	90%
2008	8%	6%	2%	84%	2%	2%	1%	95%	4%	4%	1%	91%	10%	0%	1%	89%
2009	7%	6%	4%	84%	4%	5%	3%	88%	2%	3%	2%	93%	7%	0%	2%	91%
2010	7%	8%	4%	82%	1%	6%	2%	91%	3%	2%	1%	94%	4%	1%	1%	94%
2011	10%	7%	4%	79%	3%	7%	2%	87%	2%	2%	2%	94%	3%	0%	4%	94%
2012	8%	8%	8%	77%	2%	6%	2%	90%	2%	2%	1%	95%	2%	0%	1%	97%
2013	7%	10%	4%	80%	2%	10%	3%	85%	6%	3%	1%	91%	4%	0%	1%	95%
2014	11%	5%	4%	80%	4%	10%	2%	85%	15%	3%	1%	80%	15%	0%	2%	82%
2015	9%	5%	4%	82%	3%	7%	2%	89%	4%	4%	1%	91%	10%	0%	2%	88%
2016	7%	7%	7%	79%	2%	5%	2%	92%	2%	3%	2%	94%	6%	0%	3%	91%
2017	10%	6%	8%	76%	2%	4%	2%	92%	1%	3%	2%	95%	5%	0%	1%	94%
2018	11%	7%	7%	75%	2%	4%	1%	94%	2%	3%	1%	94%	6%	1%	3%	90%
2019	9%	4%	7%	81%	1%	6%	1%	91%	2%	5%	2%	92%	6%	1%	3%	90%
2020	4%	4%	11%	82%	5%	5%	1%	88%	2%	4%	1%	93%	7%	0%	3%	90%
2021	9%	5%	11%	75%	3%	4%	3%	90%	1%	4%	3%	91%	6%	0%	3%	91%
2022	10%	7%	9%	75%	2%	6%	3%	89%	2%	4%	2%	92%	10%	1%	5%	85%
2023	7%	5%	11%	78%	4%	4%	2%	90%	2%	4%	2%	92%	13%	0%	4%	83%
2024	4%	6%	10%	80%	2%	5%	2%	91%	2%	4%	2%	93%	10%	0%	3%	87%

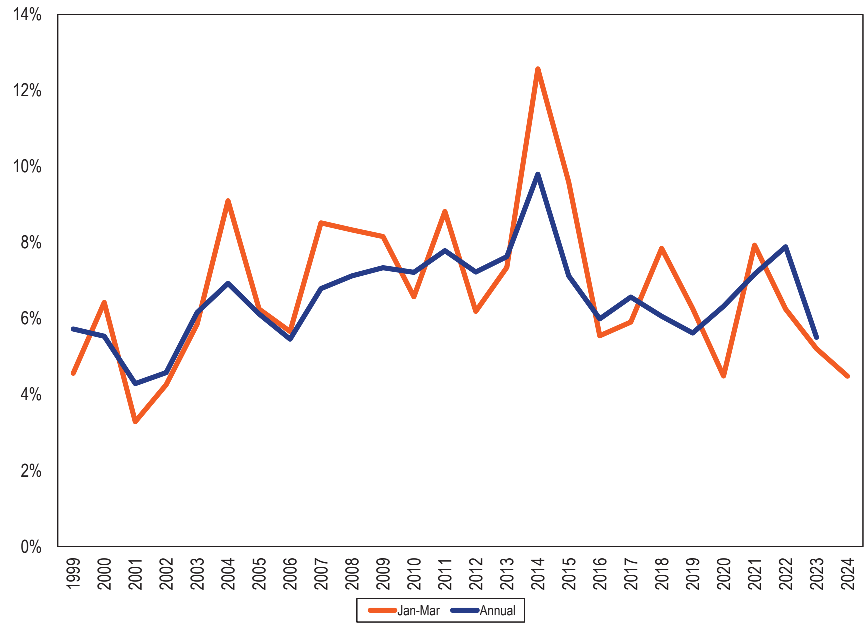
	Hydroelectric				Nuclear				Other				Total			
Jan-Mar	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF
2007	1%	8%	2%	89%	0%	5%	0%	94%	8%	4%	3%	85%	5%	5%	2%	88%
2008	1%	9%	1%	89%	2%	7%	1%	91%	4%	7%	3%	86%	5%	6%	2%	88%
2009	2%	11%	1%	87%	4%	3%	1%	91%	5%	6%	7%	82%	5%	5%	3%	87%
2010	1%	9%	1%	89%	1%	7%	0%	92%	4%	7%	2%	87%	4%	7%	2%	88%
2011	2%	10%	1%	87%	2%	3%	1%	94%	4%	5%	3%	88%	5%	5%	3%	87%
2012	2%	4%	1%	93%	1%	6%	1%	93%	5%	6%	4%	86%	4%	6%	4%	86%
2013	0%	4%	2%	93%	0%	3%	0%	96%	8%	7%	2%	83%	4%	7%	2%	86%
2014	1%	9%	6%	84%	1%	5%	0%	94%	11%	8%	5%	77%	8%	6%	3%	83%
2015	2%	10%	1%	87%	2%	5%	1%	93%	9%	11%	4%	76%	5%	6%	2%	86%
2016	2%	5%	4%	89%	0%	5%	0%	94%	4%	15%	4%	77%	4%	6%	3%	87%
2017	2%	6%	4%	88%	0%	5%	1%	94%	3%	5%	5%	88%	4%	5%	4%	87%
2018	3%	4%	2%	90%	0%	5%	0%	95%	5%	8%	6%	81%	5%	5%	4%	87%
2019	1%	6%	3%	90%	0%	5%	1%	94%	3%	8%	7%	81%	4%	5%	4%	88%
2020	3%	4%	2%	91%	2%	4%	1%	93%	3%	8%	4%	85%	3%	5%	4%	88%
2021	16%	1%	2%	81%	0%	4%	2%	94%	13%	6%	2%	79%	5%	4%	5%	86%
2022	5%	3%	2%	90%	0%	4%	1%	94%	4%	6%	4%	86%	4%	5%	4%	86%
2023	2%	17%	6%	75%	0%	4%	2%	94%	5%	8%	9%	78%	3%	5%	5%	86%
2024	3%	19%	3%	76%	1%	3%	2%	94%	3%	11%	2%	84%	2%	6%	4%	88%

Generator Outage Rates

The most fundamental forced outage rate metric is the equivalent demand forced outage rate (EFORd). EFORd is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate. EFORd measures the forced outage rate during periods of demand, and does not include planned or maintenance outages. A period of demand is a period during which a generator is running or needed to run. EFORd calculations use historical performance data, including equivalent forced outage hours, service hours, average forced outage duration, average run time, average time between unit starts, available hours and period hours.[204] The EFORd metric includes all forced outages, regardless of the reason for those outages.

The average PJM EFORd in the first three months of 2024 was 4.5 percent, a decrease from 5.2 percent in the first three months of 2023. Figure 5-9 shows the average EFORd since 1999 for all units in PJM.[205]

Figure 5-9 Equivalent demand forced outage rates (EFORd): 1999 to 2024



204 Equivalent forced outage hours are the sum of all forced outage hours in which a generating unit is fully inoperable and all partial forced outage hours in which a generating unit is partially inoperable, prorated to full hours.

205 The universe of units in PJM changed as the PJM footprint expanded and as units retired from and entered PJM markets. See the *2023 Annual State of the Market Report for PJM*, Appendix A: "PJM Overview" for details.

Table 5-34 shows the class average EFORd by unit type.

Table 5-34 EFORd by unit type: January through March, 2007 to 2024

	Jan-Mar																	
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Coal	7.6%	8.9%	8.1%	8.2%	11.8%	9.7%	8.1%	11.7%	9.8%	9.0%	12.1%	13.3%	11.8%	5.7%	12.2%	11.4%	10.8%	6.6%
Combined Cycle	10.7%	5.9%	5.9%	3.8%	4.5%	2.5%	2.4%	7.0%	4.9%	2.8%	2.8%	3.2%	3.1%	5.5%	3.1%	2.9%	4.1%	2.8%
Combustion Turbine	21.8%	18.1%	15.6%	14.3%	13.0%	8.7%	18.5%	32.2%	20.4%	8.1%	4.8%	10.7%	9.0%	4.9%	4.7%	6.5%	5.9%	8.5%
Diesel	9.1%	10.1%	8.3%	6.3%	5.2%	2.8%	3.8%	15.9%	11.1%	7.0%	6.0%	6.7%	6.7%	7.5%	6.5%	10.4%	14.6%	12.4%
Hydroelectric	1.6%	3.0%	2.0%	0.9%	2.2%	2.8%	0.6%	1.5%	2.4%	3.2%	3.1%	3.6%	1.2%	4.2%	16.9%	6.4%	1.6%	3.8%
Nuclear	0.4%	1.6%	4.0%	0.8%	1.7%	0.8%	0.2%	1.1%	1.6%	0.5%	0.5%	0.4%	0.3%	2.3%	0.2%	0.5%	0.1%	0.7%
Other	10.8%	10.2%	10.6%	5.6%	13.2%	4.6%	10.5%	19.1%	17.6%	6.4%	6.4%	12.6%	6.2%	2.7%	28.0%	10.6%	4.7%	4.8%
Total	8.5%	8.3%	8.2%	6.6%	8.8%	6.2%	7.3%	12.6%	9.6%	5.5%	5.9%	7.8%	6.3%	4.5%	7.9%	6.3%	5.2%	4.5%

EFORd vs EAF

EFORd is not an adequate measure of units' availability because EFORd measures only forced outages and does not account for planned or maintenance outages. Forced outage rates can be managed under the existing outage rules. A unit with significant planned and/or maintenance outages is considered to have identical reliability properties in capacity planning, transmission planning and in the sale of capacity in the capacity market.[206] The EAF (Equivalent Availability Factor), which reflects all forced, planned, and maintenance outages, is a more accurate measure of the capacity actually available to meet load.

Table 5-35 shows the differences between EFORd and EAF by unit type.

Table 5-35 EFORd and EAF by unit type: January through March, 2012 to 2024

	Unit Types															
	Coal		Combined Cycle		Combustion Turbine		Diesel		Hydroelectric		Nuclear		Other		All	
Jan-Mar	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF
2012	9.7%	23.0%	2.5%	9.8%	8.7%	4.7%	2.8%	2.8%	2.8%	7.2%	0.8%	7.3%	4.6%	13.6%	6.2%	14.0%
2013	8.1%	20.4%	2.4%	15.4%	18.5%	9.4%	3.8%	5.0%	0.6%	6.6%	0.2%	3.8%	10.5%	17.2%	7.3%	13.8%
2014	11.7%	19.7%	7.0%	15.4%	32.2%	19.9%	15.9%	17.6%	1.5%	16.5%	1.1%	5.8%	19.1%	23.2%	12.6%	16.5%
2015	9.8%	17.5%	4.9%	11.1%	20.4%	9.1%	11.1%	12.3%	2.4%	13.5%	1.6%	6.8%	17.6%	24.1%	9.6%	13.5%
2016	9.0%	20.8%	2.8%	8.2%	8.1%	6.5%	7.0%	8.9%	3.2%	11.3%	0.5%	6.0%	6.4%	23.1%	5.5%	13.1%
2017	12.1%	23.9%	2.8%	8.4%	4.8%	5.4%	6.0%	6.3%	3.1%	11.5%	0.5%	5.7%	6.4%	12.1%	5.9%	12.7%
2018	13.3%	24.7%	3.2%	6.4%	10.7%	6.5%	6.7%	9.8%	3.6%	9.6%	0.4%	5.5%	12.6%	18.8%	7.8%	13.2%
2019	11.8%	19.3%	3.1%	9.2%	9.0%	8.5%	6.7%	10.2%	1.2%	9.9%	0.3%	6.3%	6.2%	18.5%	6.3%	12.3%
2020	5.7%	18.4%	5.5%	11.6%	4.9%	7.1%	7.5%	9.7%	4.2%	8.9%	2.3%	7.3%	2.7%	15.5%	4.5%	12.1%
2021	12.2%	24.9%	3.1%	9.9%	4.7%	8.9%	6.5%	9.3%	16.9%	19.1%	0.2%	5.5%	28.0%	20.9%	7.9%	14.3%
2022	11.4%	25.3%	2.9%	10.8%	6.5%	7.9%	10.4%	15.4%	6.4%	10.5%	0.5%	5.7%	10.6%	13.6%	6.3%	13.5%
2023	10.8%	22.5%	4.1%	10.2%	5.9%	7.7%	14.6%	17.2%	1.6%	24.8%	0.1%	5.6%	4.7%	22.3%	5.2%	13.7%
2024	6.6%	20.1%	2.8%	9.0%	8.5%	7.5%	12.4%	13.0%	3.8%	24.4%	0.7%	6.2%	4.8%	16.4%	4.5%	12.1%
Average	10.2%	21.6%	3.6%	10.4%	11.0%	8.4%	8.6%	10.6%	3.9%	13.4%	0.7%	6.0%	10.3%	18.4%	6.9%	13.5%

206 OATT, Attachment DD (Reliability Pricing Model) § 10A (d).

Outage Analysis

The MMU analyzed the causes of outages for the PJM system. The metric used was lost generation, which is the product of the duration of the outage and the size of the outage reduction. Lost generation can be converted into lost system equivalent availability.[207] On a system wide basis, the resultant lost equivalent availability from forced outages is equal to the equivalent forced outage factor (EFOF), the resultant lost equivalent availability from maintenance outages is equal to the equivalent maintenance outage factor (EMOF), and the resultant lost equivalent availability from planned outages is equal to the equivalent planned outage factor (EPOF).

The PJM EFOF was 2.4 percent in the first three months of 2024. Table 5-36 shows the causes of EFOF by unit type. Forced outages for unit testing, 19.4 percent of the system EFOF, were the largest single contributor to average system EFOF across all unit types, although electrical and boiler tube leaks were the largest contributors to EFOF for coal plants.

Table 5-36 Contribution to PJM EFOF by unit type by cause: January through March, 2024

	Coal	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Other	System
Unit Testing	10.9%	25.1%	28.8%	18.9%	36.4%	7.8%	19.2%	19.4%
Electrical	21.0%	0.3%	5.7%	24.6%	0.5%	4.0%	26.9%	11.7%
Boiler Tube Leaks	16.6%	1.0%	0.0%	0.0%	0.0%	0.0%	7.9%	7.1%
Generator	0.0%	23.5%	0.4%	0.0%	3.6%	0.0%	0.0%	5.9%
Miscellaneous (Gas Turbine)	0.0%	7.1%	14.3%	0.0%	0.0%	0.0%	0.0%	4.2%
Boiler Air and Gas Systems	9.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.8%	3.5%
Boiler Tube Fireside Slagging or Fouling	9.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.3%
Circulating Water Systems	0.8%	11.6%	0.0%	0.0%	0.0%	1.5%	0.0%	3.2%
Low Pressure Turbine	7.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.7%
Miscellaneous (Generator)	0.0%	4.4%	1.8%	12.1%	2.4%	16.9%	0.0%	2.7%
Auxiliary Systems	4.8%	0.3%	3.5%	0.0%	0.0%	0.1%	0.4%	2.5%
Economic	0.2%	1.4%	10.2%	6.8%	3.9%	0.0%	0.6%	2.5%
Miscellaneous (Balance of Plant)	0.0%	2.7%	0.2%	0.3%	29.2%	0.0%	0.5%	2.3%
Turbine	0.0%	0.4%	8.7%	0.0%	13.1%	0.0%	0.0%	2.3%
Feedwater System	0.8%	0.0%	0.0%	0.0%	0.0%	26.5%	1.0%	2.1%
Fuel, Ignition and Combustion Systems	0.0%	2.6%	7.9%	0.0%	0.0%	0.0%	0.0%	2.0%
Fuel Quality	3.1%	0.0%	3.8%	4.6%	0.0%	0.0%	1.3%	1.9%
Boiler Fuel Supply to Bunker	1.3%	0.0%	0.0%	0.0%	0.0%	0.0%	12.3%	1.6%
Reactor Coolant System	0.0%	0.0%	0.0%	0.0%	0.0%	25.6%	0.0%	1.6%
All Other Causes	14.5%	19.5%	14.8%	32.6%	10.8%	17.6%	29.1%	17.3%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

207 For any unit, lost generation can be converted to lost equivalent availability by dividing lost generation by the product of the generating units' capacity and period hours. This can also be done on a system basis.

The PJM EMOF was 4.0 percent in the first three months of 2024. Table 5-37 shows the causes of EMOF by unit type. Maintenance outages for boiler air and gas systems, 18.2 percent of the system EMOF, were the largest single contributor to average system EMOF across all unit types, although auxiliary system issues were the largest contributors to EMOF for combustion turbines.

Table 5-37 Contribution to EMOF by unit type by cause: January through March, 2024

	Coal	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Other	System
Boiler Air and Gas Systems	28.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	18.2%
Miscellaneous (Reactor)	0.0%	0.0%	0.0%	0.0%	0.0%	83.7%	0.0%	12.1%
Electrical	10.1%	1.6%	9.6%	2.4%	37.6%	0.0%	0.0%	8.5%
Cooling System	10.1%	0.0%	0.0%	0.7%	0.7%	0.0%	0.0%	6.4%
Boiler Tube Leaks	6.6%	0.9%	0.0%	0.0%	0.0%	0.0%	30.2%	5.2%
Boiler Piping System	6.0%	17.0%	0.0%	0.0%	0.0%	0.0%	0.0%	5.0%
Boiler Tube Fireside Slagging or Fouling	5.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.4%	3.2%
Boiler Internals and Structures	4.4%	5.0%	0.0%	0.0%	0.0%	0.0%	0.1%	3.2%
Auxiliary Systems	0.2%	4.3%	29.6%	0.3%	0.0%	0.0%	0.0%	2.8%
Circulating Water Systems	3.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.3%
Precipitators	3.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.2%
Miscellaneous (Gas Turbine)	0.0%	6.2%	17.4%	0.0%	0.0%	0.0%	0.0%	1.8%
Miscellaneous (Boiler)	1.3%	0.0%	0.0%	0.0%	0.0%	0.0%	31.4%	1.8%
Boiler Overhaul and Inspections	2.8%	0.0%	0.0%	0.0%	0.0%	0.0%	2.2%	1.8%
Dry Scrubbers	2.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.8%
Lube Oil	2.6%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	1.7%
Valves	0.6%	14.4%	0.0%	0.0%	0.0%	0.2%	0.8%	1.5%
Fuel, Ignition and Combustion Systems	0.0%	11.1%	7.1%	0.0%	0.0%	0.0%	0.0%	1.4%
Boiler Fuel Supply from Bunkers to Boiler	2.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.1%	1.3%
All Other Causes	9.9%	39.3%	36.3%	96.7%	61.8%	16.1%	34.7%	17.7%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

PJM EPOF was 5.7 percent in the first three months of 2024. Table 5-38 shows the causes of EPOF by unit type. Planned outages for miscellaneous balance of plant issues, 20.9 percent of the system EPOF, were the largest single contributor to average system EPOF across all unit types, although miscellaneous gas turbine issues were the largest contributors to EPOF for combustion turbines.

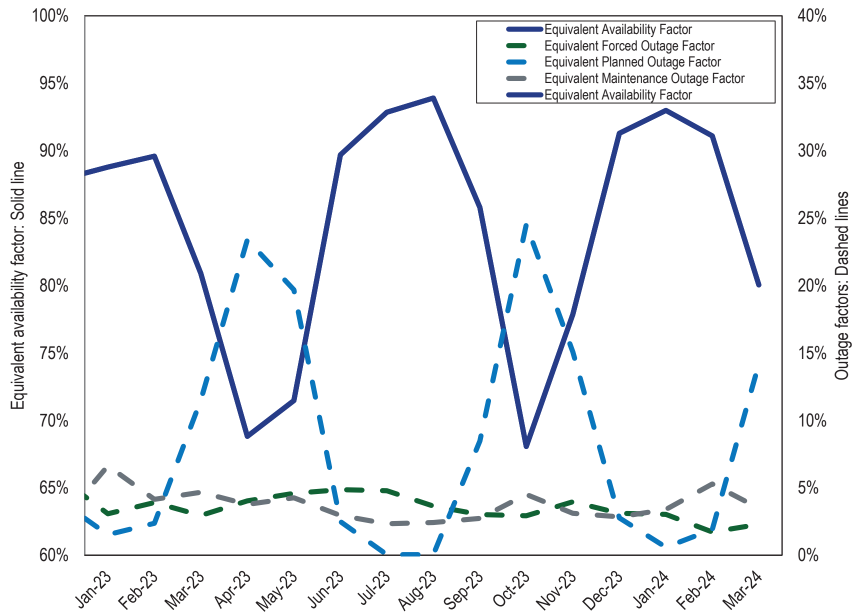
Table 5-38 Contribution to EPOF by unit type and cause: January through March, 2024

	Coal	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Other	System
Miscellaneous (Balance of Plant)	24.8%	35.5%	27.8%	0.0%	0.0%	0.0%	34.8%	20.9%
Core/Fuel	0.0%	0.0%	0.0%	0.0%	0.0%	96.9%	0.0%	12.5%
Boiler Overhaul and Inspections	14.0%	9.8%	0.0%	0.0%	0.0%	0.0%	28.2%	9.0%
Miscellaneous (Gas Turbine)	0.0%	12.6%	42.3%	0.0%	0.0%	0.0%	0.0%	7.8%
Generator	0.0%	0.0%	0.0%	0.0%	44.4%	0.0%	0.0%	7.6%
Boiler Piping System	6.0%	24.1%	0.0%	0.0%	0.0%	0.0%	0.0%	5.9%
Miscellaneous (Generator)	11.7%	0.0%	0.4%	0.0%	12.4%	0.0%	0.0%	5.3%
Boiler Control Systems	13.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.4%
Miscellaneous (Steam Turbine)	8.0%	5.8%	0.0%	0.0%	0.0%	0.0%	0.0%	3.1%
NOx Reduction Systems	10.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.9%
Miscellaneous (Boiler)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	21.7%	2.7%
Exciter	0.0%	0.0%	0.0%	0.0%	14.2%	0.0%	0.0%	2.4%
Water Supply/Discharge	0.0%	0.0%	0.0%	0.0%	13.4%	0.0%	0.0%	2.3%
Turbine	0.0%	1.9%	0.0%	0.0%	11.1%	0.0%	0.0%	2.2%
Miscellaneous (Pollution Control Equipment)	6.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.7%
Valves	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	13.4%	1.7%
Unit Testing	0.0%	2.6%	6.3%	0.0%	0.0%	0.0%	0.0%	1.3%
Exhaust Systems	0.0%	0.0%	8.4%	0.0%	0.0%	0.0%	0.0%	1.1%
Fuel, Ignition and Combustion Systems	0.0%	5.0%	1.0%	0.0%	0.0%	0.0%	0.0%	1.0%
All Other Causes	5.4%	2.7%	13.8%	100.0%	4.5%	3.1%	1.9%	5.1%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Performance by Month

Monthly values for EAF, EFOF, EMOF and EPOF are shown in Figure 5-10.

Figure 5-10 Monthly generator performance factors: 2023 through March 2024



Generator Testing Issues

PJM Manual 21: Rules and Procedures for Determination of Generating Capability describes how generators are to be tested. PJM's testing requirements are not well designed, permit excessive generator discretion, and do not require adequate winter testing.

Net Capability Verification Testing data, meant to demonstrate that a unit has the ICAP claimed, are submitted for the summer and winter testing periods.[208] These periods run from the start of June until September and the start of December until March. If a unit is on a planned or maintenance outage for the entire testing period, it is expected to perform an out of period test once the outage ends. Out of period tests can be performed from the start of September until December for summer tests and from the start of March until June for winter tests. Hydroelectric generators only perform summer tests.[209] Wind and solar resources do not perform verification tests to prove capability.[210]

While data must be submitted for the winter testing period, PJM permits the use of summer test data adjusted for ambient winter conditions in lieu of actual winter test data. The MMU recommends that PJM require actual seasonal tests as part of the Summer/Winter Capability Testing rules and that the ambient conditions under which the tests are performed be defined.

Results, including failed test results, must be submitted to PJM via eGADS. Failing to submit data before the deadline can result in a Data Submission Charge of $500 per day late.[211]

Failure to demonstrate the claimed net capability results in a forced outage or derating effective from the beginning of the testing period and lasting until either a reduced claimed ICAP is in effect, the beginning of the next testing period, or, except for failures due to environmental constraints or a lack of resources, a successful out of period test.

Failed test results must be accompanied by a derating or outage in eGADS and in eDART. Failure to report failed tests and to derate the unit can result in a Generation Resource Rating Test Failure Charge, equal to the Daily Deficiency Rate multiplied by: the daily ICAP shortfall multiplied by one minus the effective EFORd for unlimited resources; the UCAP for the daily ICAP shortfall, for limited duration resources and combination resources.[212] There were no such charges assessed for 2024.

The Daily Deficiency Rate in dollars per MW-day is equal to the weighted average capacity resource clearing price from the RPM auction that resulted

208 PJM. "PJM Manual 18: PJM Capacity Market," § 8.5 Summer/Winter Capability Testing, Rev. 57 (July 26, 2023).

209 PJM. "PJM Manual 18: PJM Capacity Market," § 8.5 Summer/Winter Capability Testing, Rev. 58 (Nov. 15, 2023).

210 PJM. "PJM Manual 18: PJM Capacity Market," Appendix B: Calculating Capacity Values for Wind and Solar Capacity Resources, Rev. 58 (Nov. 15, 2023).

211 "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 12, Section A.

212 PJM. "PJM Manual 18: PJM Capacity Market," § 9.1.5 Generation Resource Rating Test Failure Charge, Rev. 58 (Nov. 15, 2023).

in the resource's commitment plus the greater of 20 percent of that clearing price or 20 dollars per MW-day.[213]

While generation owners are required to report failed tests and to derate their unit in eGADS, owners can perform an unlimited number of tests before submitting a successful result. The MMU recommends that PJM limit the number of tests that can be made before submitting final results and that the data be collected by power meter instead of being submitted in eGADS. The MMU recommends that PJM select the time and day for testing a unit, not the unit owner, and that this testing not be communicated in advance. Instead, a unit would be tested by how well it follows its dispatch signal. Under the current testing rules, generation owners have the opportunity to perform tests during more favorable conditions to achieve better performance.

Generator output is also assessed during Performance Assessment Intervals (PAIs), which occur when PJM declares an emergency action as listed in Manual 18, Section 8.4A. If a unit fails to perform as expected, generators may incur a Non-Performance Charge, which is equal to the performance shortfall multiplied by the Non-Performance Charge Rate.[214] In 2022, PAIs occurred on June 13, June 14, June 15, December 23, and December 24. For the December 23 and 24 PAIs, PJM total nonperformance charges were approximately $1.796 billion, reduced to $1.226 billion in a settlement agreement.[215] There were no such charges assessed in 2023 or in the first three months of 2024.

For each day of a delivery year, generators are required to meet their daily unforced capacity commitments. Generation owners have the option to buy replacement capacity that satisfies the same locational requirements.[216] [217] Failure to meet this commitment can result in a Daily Capacity Resource Deficiency Charge.[218] [219] This charge is equal to the Daily Deficiency Rate multiplied by the difference between a resource's daily commitments and daily position. Thirty resources were assessed for deficiency charges in 2021, 64 resources were assessed for deficiency charges in 2022, 175 resources were assessed for deficiency charges in 2023, and 137 resources were assessed for deficiency charges in the first three months of 2024.

Changing Outage Types

Capacity resource owners have an incentive to minimize their forced outages to maximize capacity revenue and minimize penalties. Generation owners have had the ability to change the designation of the outage type after the initial submission to the eGADS database since 2014. Table 5-39 shows that from 2014 through March 2024, of all the changes in outage status, 96.4 percent of the outages and 87.5 percent of the outage MWh were changed from either planned or maintenance to forced outage status. Of those changes to forced outage status, 40.0 percent of the outages and 74.6 percent of the MWh were for coal and hydro plants.

213 OATT, Attachment DD (Reliability Pricing Model) § 7.
214 OATT, Attachment DD (Reliability Pricing Model) § 10A.
215 See Settlement Agreement, Docket No. ER23-2975-000 (September 29, 2023), which can be accessed at: <https://pjm.com/-/media/documents/ferc/filings/2023/20230929-er23-2975-000.ashx>.
216 "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," § 1.3.6 Impacts of Test Results, Rev. 18 (July 26, 2023).
217 OATT, Attachment DD (Reliability Pricing Model) § 7 (a).
218 PJM. "PJM Manual 18: PJM Capacity Market," § 8.2 RPM Commitment Compliance, Rev. 58 (Nov. 15, 2023).
219 OATT, Attachment DD (Reliability Pricing Model) § 8.

Table 5-39 Changed outages by unit type: 2014 through March 2024[220]

		Forced to Maintenance		Forced to Planned		Maintenance or Planned to Forced	
Unit Type	Year	No. Outages	MWh	No. Outages	MWh	No. Outages	MWh
Coal	2014	5	270,049	0	NA	1	2,794
	2015	0	NA	0	NA	25	876,920
	2016	1	271,304	0	NA	74	1,983,852
	2017	2	151,085	0	NA	48	1,246,484
	2018	1	1,520	0	NA	30	837,286
	2019	2	71,234	0	NA	43	618,382
	2020	1	8,587	0	NA	12	170,807
	2021	0	NA	0	NA	0	NA
	2022	0	NA	0	NA	0	NA
	2023	1	13,211	0	NA	0	NA
	2024 (Jan-Mar)	0	NA	0	NA	0	NA
	Total	13	786,990	0	NA	233	5,736,526
Combined Cycle	2014	1	3,803	2	1,105	1	28,067
	2015	2	24,685	0	NA	3	3,330
	2016	0	NA	1	65,664	24	145,432
	2017	3	5,786	0	NA	19	400,606
	2018	1	416	0	NA	16	52,214
	2019	0	NA	0	NA	11	94,756
	2020	0	NA	0	NA	13	19,037
	2021	0	NA	7	303,061	0	NA
	2022	0	NA	1	3,817	2	208
	2023	0	NA	0	NA	0	NA
	2024 (Jan-Mar)	0	NA	0	NA	0	NA
	Total	7	34,690	11	373,648	89	743,650
Combustion Turbine	2014	9	26,990	3	15,027	22	25,865
	2015	0	NA	0	NA	13	27,567
	2016	0	NA	0	NA	48	55,233
	2017	0	NA	0	NA	19	29,586
	2018	0	NA	2	41,737	25	24,433
	2019	0	NA	1	340	28	37,483
	2020	0	NA	0	NA	27	41,312
	2021	0	NA	0	NA	5	25,094
	2022	0	NA	0	NA	5	25,497
	2023	0	NA	0	NA	2	270,221
	2024 (Jan-Mar)	0	NA	0	NA	0	NA
	Total	9	26,990	6	57,104	194	562,290
Diesel	2014	0	NA	0	NA	77	4,550
	2015	15	47	0	NA	182	5,439
	2016	0	NA	0	NA	217	5,579
	2017	2	145	0	NA	175	5,883
	2018	2	15	0	NA	235	4,414
	2019	0	NA	0	NA	238	23,066
	2020	2	311	0	NA	163	6,113
	2021	3	137	0	NA	3	27,059
	2022	4	5,492	0	NA	10	305
	2023	0	NA	0	NA	0	NA
	2024 (Jan-Mar)	0	NA	0	NA	0	NA
	Total	28	6,147	0	NA	1,300	82,408
Hydroelectric	2014	1	3	0	NA	124	1,383,319
	2015	1	162	0	NA	152	952,608
	2016	4	780	0	NA	315	1,433,851
	2017	2	52,080	0	NA	123	598,766
	2018	4	82,395	0	NA	72	405,549
	2019	0	NA	0	NA	34	148,629
	2020	0	NA	0	NA	59	281,976
	2021	0	NA	0	NA	33	263,525
	2022	0	NA	0	NA	1	4,887
	2023	0	NA	0	NA	9	196,512
	2024 (Jan-Mar)	0	NA	0	NA	0	NA
	Total	12	135,420	0	NA	922	5,669,622
Nuclear	2014	0	NA	1	177,618	0	NA
	2015	0	NA	1	573	0	NA
	2016	0	NA	0	NA	0	NA
	2017	0	NA	0	NA	0	NA
	2018	0	NA	0	NA	0	NA
	2019	0	NA	0	NA	0	NA
	2020	0	NA	0	NA	2	22,903
	2021	0	NA	0	NA	0	NA
	2022	0	NA	0	NA	0	NA
	2023	0	NA	0	NA	0	NA
	2024 (Jan-Mar)	0	NA	0	NA	0	NA
	Total	0	NA	2	178,191	2	22,903
Other	2014	5	103,981	0	NA	1	866
	2015	0	NA	0	NA	2	176,599
	2016	1	11,680	0	NA	18	159,781
	2017	2	231	1	28,636	12	85,071
	2018	3	7,555	0	NA	1	268
	2019	1	128,664	1	8,658	9	61,297
	2020	0	NA	0	NA	4	82,250
	2021	0	NA	0	NA	0	NA
	2022	0	NA	0	NA	0	NA
	2023	2	17,023	0	NA	0	NA
	2024 (Jan-Mar)	0	NA	0	NA	0	NA
	Total	14	269,134	2	37,294	47	566,132
All Units	2014	21	404,826	6	193,750	226	1,445,461
	2015	18	24,894	1	573	377	2,042,463
	2016	6	283,764	1	65,664	696	3,783,728
	2017	11	209,328	1	28,636	396	2,366,397
	2018	11	91,901	2	41,737	379	1,324,165
	2019	3	199,897	2	8,998	363	983,612
	2020	3	8,898	0	NA	280	624,398
	2021	3	137	7	303,061	41	315,679
	2022	4	5,492	1	3,817	18	30,896
	2023	3	30,234	0	NA	11	466,733
	2024 (Jan-Mar)	0	NA	0	NA	0	NA
	Total	83	1,259,370	21	646,237	2787	13,383,531

220 Year describes the year in which the outage started and not the year in which the outage designation was changed.