

Capacity Market

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

PJM's introduction of its significantly modified ELCC method in the 2025/2026 BRA was another radical change to the capacity market design. While it is a good idea to evaluate unit specific performance and a good idea to recognize that risk occurs in the winter as well as the summer and that risks are correlated, ELCC was implemented before it could be fully tested and unintended consequences evaluated. The results of the 2025/2026 BRA illustrate the extreme sensitivity of the market outcomes to a range of assumptions and decisions about market design details that were not adequately tested or reviewed with stakeholders.

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 are required to offer into the capacity auctions. The current exception of intermittent and storage capacity from the must offer requirement is inconsistent with the PJM market design and the significance of this exception is growing. 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 offer them into the capacity market, or construct transmission upgrades and offer them into the capacity market.

There are significant market design issues in the PJM Capacity Market that currently prevent the market from achieving competitive results.

The Market Monitoring Unit (MMU) analyzed market design, market structure, participant conduct and market performance in the PJM Capacity Market, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.¹ The conclusions are a result of the MMU’s evaluation of the 2025/2026 Base Residual Auction.^{2 3 4}

Table 5-1 The capacity market results were not competitive

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

- The aggregate market structure was evaluated as not competitive. For almost all auctions held from 2007 to the present, the PJM capacity market failed the three pivotal supplier test (TPS), which is conducted at the time of the auction.⁵ 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.⁶

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 "Analysis of the 2025/2026 RPM Base Residual Auction - Part A," (September 20, 2024) <https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_A_20240920.pdf>.

³ See "Analysis of the 2025/2026 RPM Base Residual Auction - Part B," (October 15, 2024) <https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_B_20241015.pdf>.

⁴ See "Analysis of the 2025/2026 RPM Base Residual Auction - Part C," (November 6, 2024) <https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_C_20241106.pdf>.

⁵ 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.

⁶ In the 2012/2013 RPM Base Residual Auction, six participants included in the incremental supply of EMAAC passed the TPS test. In the 2014/2015 RPM Base Residual Auction, seven participants in the incremental supply in MAAC passed the TPS test. In the 2021/2022 RPM First Incremental Auction, two participants in the incremental supply in EMAAC passed the TPS test. In the 2021/2022 RPM Second Incremental Auction, two participants in the incremental supply in EMAAC passed the TPS test. In the 2023/2024 RPM Third Incremental Auction, eight participants in MAAC passed the TPS test.

- Participant behavior was evaluated as not competitive in the 2025/2026 BRA. The offers of most market sellers were competitive after the Commission order corrected the definition of the market seller offer cap.⁷ 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. However, a significant level of categorically exempt resources did not offer and the result was to increase the clearing prices above the competitive level.
- Market performance was evaluated as not competitive based on the 2025/2026 Base Residual Auction as a result of the failure to offer of categorically exempt resources, the flaws in the Effective Load Carrying Capability (ELCC) design including the failure to correctly define the reliability contribution of thermal resources in the winter and the failure to include reliability must run (RMR) capacity in the supply curve.
- Market design was evaluated as mixed because while there are many positive features of the capacity market design, there are several features of the RPM design which still threaten competitive outcomes. These include the details of PJM’s ELCC implementation, the failure to apply the RPM must offer requirement consistently, the inclusion of performance assessment interval (PAI) penalties, the exclusion of RMR resources from supply, the use of gross CONE as the maximum price on the VRR curve, the definition of DR which permits inferior products to substitute for capacity, the replacement capacity issue, the definition of unit offer parameters, and the inclusion of imports which are not substitutes for internal capacity resources.

⁷ 176 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.

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 PJM introduced the Capacity Performance design for the 2017/2018 BRA. PJM introduced a new ELCC method for defining capacity MW offered in the 2025/2026 BRA.⁹

Under RPM, capacity obligations are annual.¹⁰ By design, Base Residual Auctions (BRA) are held for delivery years that are three years in the future despite recent auction delays. First, Second and Third Incremental Auctions (IA) are held for each delivery year.¹¹ First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year although some incremental auctions have not been held as a result of delays in holding BRAs.¹² 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.¹³

The 2024/2025 RPM Third Incremental Auction and the 2025/2026 RPM Base Residual Auction were conducted in the first nine months of 2024. Based on the FERC Order in Docket No. ER23-729-002, PJM reran the 2024/2025 RPM Base Residual Auction with final results posted on May 6, 2024, and PJM reran the 2024/2025 Third Incremental Auction with final results posted

on May 23, 2024.^{14 15 16} The 2025/2026 RPM Base Residual Auction was conducted in July 2024.

Market Structure

- **RPM Installed Capacity.** In the first nine months of 2024, RPM installed capacity decreased 1,342.6 MW or 0.8 percent, from 178,375.0 MW on January 1, to 177,032.4 MW on September 30. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- **Reserves.** For the 2025/2026 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 14,319.1 MW, or 71.1 percent of required reserves and 68.1 percent of total reserves. The fact that more than two thirds (68.1 percent) of the PJM reserves depend on resources that are not subject to the RPM must offer requirement, a core part of the capacity market design, means that reliability is significantly less certain than the stated reserve margins indicate.
- **RPM Installed Capacity by Fuel Type.** Of the total installed capacity on September 30, 2024, 50.1 percent was gas; 21.4 percent was coal; 18.2 percent was nuclear; 4.3 percent was hydroelectric; 2.2 percent was oil; 1.0 percent was wind; 0.3 percent was solid waste; and 2.5 percent was solar.
- **Market Concentration.** In the 2024/2025 RPM Third Incremental Auction and the 2025/2026 RPM Base Residual Auction, all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.¹⁷ 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

⁸ The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in this report and include all capacity within the PJM footprint.

⁹ See 186 FERC ¶ 61,080 (2024), *reh'g order*, 189 FERC ¶ 61,043 (2024).

¹⁰ 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.

¹¹ See 126 FERC ¶ 61,275 at P 86 (2009).

¹² See Letter Order, FERC Docket No. ER10-366-000 (January 22, 2010).

¹³ See 126 FERC ¶ 61,275 at P 88 (2009). There have been no Conditional Incremental Auctions.

¹⁴ 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.

¹⁵ 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).

¹⁶ 187 FERC ¶ 61,065 (2024).

¹⁷ 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).

the submitted sell offer, absent mitigation, increased the market clearing price.^{18 19 20}

- **Imports and Exports.** Of the 1,268.5 MW of imports offered in the 2025/2026 RPM Base Residual Auction, 1,268.5 MW cleared. Of the cleared imports, 700.5 MW (55.2 percent) were from MISO.
- **Demand Resources.** Committed DR was 7,699.9 MW for June 1, 2024, as a result of cleared capacity for demand resources in RPM auctions for the 2024/2025 Delivery Year (8,064.7 MW) less replacement capacity (364.8 MW).
- **Energy Efficiency Resources.** EE is not a capacity resource but is paid the capacity market clearing price as a subsidy. Committed EE was 7,668.0 MW for June 1, 2024, as a result of MW offered at a price less than or equal to the RPM auction clearing price for the 2024/2025 Delivery Year (7,716.0 MW) less replacement MW (48.0 MW).

Market Conduct

- **2024/2025 RPM Third Incremental Auction.** Of the 320 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for seven generation resources (2.2 percent).
- **2025/2026 RPM Base Residual Auction.** Of the 1,119 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for 61 generation resources (5.5 percent).

Market Performance

- The 2024/2025 RPM Third Incremental Auction and the 2025/2026 RPM Base Residual Auction were conducted in the first nine 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

¹⁸ See OATT Attachment DD § 6.5.

¹⁹ 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).

²⁰ 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).

Delivery Year is \$45.57 per MW-day, including all RPM auctions for the 2024/2025 Delivery Year.

- For the 2024/2025 Delivery Year, RPM annual charges to load are \$2.5 billion.
- In the 2025/2026 RPM Base Residual Auction, the market performance was determined to be not competitive.

Part V Reliability Service (RMR)

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

Generator Performance

- **Forced Outage Rates.** The average PJM EFORD in the first nine months of 2024 was 5.0 percent, a decrease from 5.6 percent in the first nine months of 2023.²¹
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor in the first nine months of 2024 was 86.0 percent, an increase from 84.5 percent in the first nine months of 2023.

Recommendations²²

Definition of Capacity

- The MMU recommends elimination of the key remaining components of the CP model because they interfere with competitive outcomes in the capacity market and create unnecessary complexity and risk. (Priority: High. First reported 2022. Status: Not adopted.)

²¹ 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 October 29, 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.

²² 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.

- The MMU recommends the enforcement of a consistent definition of capacity resources. The MMU recommends that the tariff requirement to be a physical resource be enforced and enhanced. The requirement to be a physical resource should apply at the time of auctions and should also constitute a commitment to be physical in the relevant delivery year. The requirement to be a physical resource should be applied to all resource types, including planned generation, demand resources, and imports.^{23 24} (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that DR providers be required to have a signed contract with specific customers for specific facilities for specific levels of DR at least six months prior to any capacity auction in which the DR is offered. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that Energy Efficiency Resources (EE) not be included in the capacity market construct because PJM's load forecasts have accounted for EE since the 2016 load forecast for the 2019/2020 Delivery Year. EE is not a capacity resource as defined in the tariff, and there is no reason to continue to pay large subsidies to EE providers.²⁵ (Priority: Medium. First reported 2016. Status: Adopted 2024.)²⁶
- 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 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.)²⁷

- The MMU recommends that the must offer rule in the capacity market apply to all capacity resources. There is no reason to exempt intermittent and capacity storage resources, including hydro, and demand resources from the must offer requirement. The same rules should apply to all capacity resources in order to ensure open access to the transmission system and prevent the exercise of market power through withholding. (Priority: High. First reported 2021. Status: 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 2023. Status: Partially adopted.)
- The MMU recommends that the ELCC be significantly refined to include hourly data that would permit unit specific ELCC ratings, to weight summer and winter risk in a more balanced manner, to eliminate PAI risks, and to pay for actual hourly performance rather than based on relatively inflexible class capacity accreditation ratings derived from a small number of hours of poor performance. (Priority: High. First reported 2023. Status: Not 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.)

²³ See also Comments of the Independent Market Monitor for PJM, Docket No. ER14-503-000 (December 20, 2013).

²⁴ 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).

²⁵ "PJM Manual 19: Load Forecasting and Analysis," § 3.2 Development of the Forecast, Rev. 36 (Nov. 15, 2023).

²⁶ See 189 FERC ¶ 61,095 (2024).

²⁷ This recommendation was first made in the 2020/2021 BRA report in 2017. See the "Analysis of the 2020/2021 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Analysis_of_the_20202021_RPM_BRA_20171117.pdf> (November 11, 2017).

- The MMU recommends that the maximum price on the VRR curve be defined as 1.5 times net CONE. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that the reference resource be a CT rather than a CC. The MMU recommends that the ELCC value used to convert the gross CONE in ICAP terms for a CT to the gross CONE in UCAP terms be the ELCC based on winter ratings. (Priority: High. New recommendation. 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 including transmission constraints inside LDAs. The market design should clear and pay units that are needed for reliability per PJM's transmission reliability analysis in order to forestall RMRs. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM clear the capacity market based on nodal capacity resource locations and the characteristics of the transmission system inside and outside LDAs consistent with the actual electrical facts of the grid. Absent a fully nodal capacity market clearing process, the MMU recommends that PJM use a non-nested model with all LDAs modeled including VRR curves for all LDAs. Each LDA requirement should be met with the capacity resources located within the LDA and exchanges from neighboring LDAs up to the transmission limit. LDAs should be allowed to price separate if that is the result of the LDA supply curves and the transmission constraints between LDAs. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that the net revenue offset calculation used by PJM to calculate the net Cost of New Entry (CONE) and net ACR be based on a forward looking calculation of expected energy and ancillary services net revenues using historical net revenues that are scaled based on forward prices for energy and fuel. (Priority: High. First reported 2014. Status: Not adopted.)²⁸
- The MMU recommends that PJM reduce the number of incremental auctions to a single incremental auction held three months prior to the start of the delivery year and reevaluate the triggers for holding conditional incremental auctions. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM not sell back any capacity in any IA procured in a BRA. If PJM continues to sell back capacity, the MMU recommends that PJM offer to sell back capacity in incremental auctions only at the BRA clearing price for the relevant delivery year. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM not buy any capacity in any IA if PJM has already procured excess reserves. (Priority: Medium. First reported 2023. Status: Not adopted.)
- The MMU recommends changing the RPM solution method to explicitly incorporate the cost of uplift (make whole) payments in the objective function. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that the Fixed Resource Requirement (FRR) rules, including obligations and performance requirements, be revised and updated to ensure that the rules reflect current market realities and that FRR entities do not unfairly take advantage of those customers paying for capacity in the PJM capacity market. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that the value of CTRs be defined by the total MW cleared in the capacity market, the internal MW cleared and the imported MW cleared, and not redefined later prior to the delivery year. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that the market clearing results be used in settlements rather than the reallocation process currently used, or that the process of modifying the obligations to pay for capacity be reviewed. (Priority: Medium. First reported 2021. Status: Not adopted.)²⁹

²⁸ 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>>.

²⁹ 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/JMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf> (October 28, 2022).

- The MMU recommends that PJM improve the clarity and transparency of its CETL calculations. The MMU also recommends that CETL for capacity imports into PJM be based on the ability to import capacity only where PJM capacity exists and where that capacity has a must offer requirement in the PJM Capacity Market. (Priority: Medium. First reported 2021. Status: Partially adopted 2022.)

Offer Caps, Offer Floors, and Must Offer

- The MMU recommends using the lower of the cost or price-based energy market offer to calculate energy costs in the calculation of the historical net revenues which are an offset to gross ACR in the calculation of unit specific capacity resource offer caps based on net ACR. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that modifications to existing resources 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 resource or an existing resource. (Priority: Medium. First reported 2017. Status: Not adopted.)³⁰
- 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.)³¹
- 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.)

³⁰ 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).

³¹ 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).

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

- 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.)

Performance Incentive Requirements of RPM

- The MMU recommends that any unit not capable of supplying energy equal to its day-ahead must offer requirement (ICAP) be required to reflect an appropriate outage and associated performance penalty. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that retroactive replacement transactions associated with a failure to perform during a PAI not be allowed and that, more generally, retroactive replacement capacity transactions not be permitted. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that there be an explicit requirement that capacity resource offers in the day-ahead energy market be competitive, where competitive is defined to be the short run marginal cost of the units, including flexible operating parameters. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that Capacity Performance resources be required to perform without excuses. Resources that do not perform should not be paid regardless of the reason for nonperformance. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that 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 2022. Status: Not adopted.)
- The MMU recommends that PJM select the time and day that a unit undergoes Net Capability Verification Testing, not the unit owner, and that this information not be communicated in advance to the unit owner. (Priority: Medium. First reported 2022. Status: Not adopted.)

Capacity Imports and Exports

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

Deactivations/Retirements

- The MMU recommends that the notification requirement for deactivations be extended from the current one quarter prior (See Table 5-26) to 12 months prior to an auction in which the unit will not be offered due to deactivation; and no less than 12 months prior to the date of deactivation (Priority: Low. First reported 2012. Status: Partially adopted.)
- The MMU recommends 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

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).

that provides for the recovery of 100 percent of the actual incremental costs required to operate to provide the service plus a defined incentive. (Priority: High. First reported 2017. Status: Not adopted.)

- The MMU recommends that units recover all and only the incremental costs, including incremental investment costs without a cap, required to provide Part V reliability service (RMR service) that the unit owner would not have incurred if the unit owner had deactivated its unit as it proposed, plus a defined incentive payment. Customers should bear no responsibility for paying previously incurred (sunk) costs, including a return on or of prior investments. (Priority: High. First reported 2010. Status: Not adopted.)
- The MMU recommends that the same reliability standard be used in capacity auctions as is used by PJM transmission planning. One result of the current design is that a unit may fail to clear in a BRA, decide to retire as a result, but then be found to be needed for reliability by PJM planning and paid under Part V of the OATT (RMR) to remain in service while transmission upgrades are made. (Priority: High. First reported 2023. Status: Not adopted.)
- The MMU recommends 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 2023. Status: Not adopted.)
- The MMU recommends that if units that are paid under Part V of the OATT (RMR) are included in the calculation of CETO and/or reliability in the relevant LDA, the capacity of the RMR resources should also be included in capacity market supply at zero cost, but without all the obligations of a capacity resource, in order to ensure that the capacity market price signal reflects the appropriate supply and demand conditions. (Priority: High. First reported 2023. Status: Not adopted.)
- The MMU recommends that all CIRs be returned to the pool of available interconnection capability on the retirement date of generation resources in order to facilitate timely and competitive entry into the PJM markets,

open access to the transmission system and maintain the priority order defined by the queue process. (Priority: High. First reported 2023. Status: Not adopted.)

Conclusion

The analysis of the PJM Capacity Market begins with market design and market structure, which provide the framework for the actual behavior or conduct of market participants. The analysis examines participant behavior within that market design and market structure. Regardless of the ownership structure of a market, the market design can result in noncompetitive outcomes. In a good market design and a competitive market structure, market participants are constrained to behave competitively. In a market with endemic structural market power like the PJM Capacity Market, effective market power mitigation rules are required in order to constrain market participants to behave competitively. The analysis examines market performance, measured by price and the relationship between price and marginal cost, that results from the interaction of market structure and participant behavior. The analysis also examines the impact of market design choices on market performance.

The MMU concludes that the results of the 2025/2026 RPM Base Residual Auction were significantly affected by flawed market design decisions including by the CP design, by PJM's ELCC approach, by the definition of the maximum VRR price as gross CONE, by the failure to extend the RPM must offer requirement to all resources, including, in some cases, the exercise of market power through the withholding of categorically exempt resources, by the product definition and lack of market power mitigation for demand resources, and by the exclusion from supply of the defined RMR resources. The BRA prices do not solely reflect supply and demand fundamentals but also reflect, in significant part, PJM decisions about the definition of supply and demand. The auction results were not solely the result of the introduction of the market design and do in significant part reflect the tightening of supply and demand conditions in the PJM Capacity Market.³⁴

The capacity market is, by design, always tight in the sense that total supply is generally only slightly larger than demand. While the market may be

³⁴ PJM's ELCC filing that created many of these issues was approved by FERC. 186 FERC ¶ 61,080 (January 30, 2024).

long at times, that is not the equilibrium state. Market power is and will remain endemic to the structure of the PJM Capacity Market. Nonetheless, a competitive outcome can be assured by appropriate market power mitigation rules within an effective market design. Detailed market power mitigation rules are included in the PJM Open Access Transmission Tariff (OATT or Tariff). Reliance on the RPM design for competitive outcomes means reliance on the market power mitigation rules.

The demand for capacity includes expected peak load plus a reserve margin, and points on the demand curve, called the Variable Resource Requirement (VRR) curve, exceed peak load plus the reserve margin. The maximum price on the VRR curve has a significant impact on market prices particularly when the market is tight. The shape of the VRR curve results in the purchase of excess capacity and higher payments by customers. The VRR curves used in the 2025/2026 BRA included a maximum price equal to gross CONE for most LDAs that resulted in a significant increase in customer payments for load as a result of paying a price above the competitive level. Demand for capacity is almost entirely inelastic because the market rules require loads to purchase their share of the system capacity requirement. The VRR demand curve is everywhere inelastic. The result is that any supplier that owns more capacity than the typically small difference between total supply and the defined demand is individually pivotal and therefore has structural market power.

For the 2025/2026 RPM Base Residual Auction, the level of committed demand resources (6,085.6 MW UCAP) exceeds the entire level of excess capacity (870.9 MW). This is not consistent with the defined obligations of DR compared to other capacity resources. DR capacity resources do not have a must offer obligation in the energy market. The definition of performance for DR is not to provide a defined incremental level of MW when called but is only to be at a defined level of demand. DR capacity resources do not have a defined market seller offer cap. PJM markets for the first time in 2025/2026 will rely on demand response resources as part of the required reserve margin, rather than as excess above the required reserve margin. PJM markets for the first time in 2025/2026 will experience the implications of the definition of

demand resources as a purely emergency capacity resource, when demand resources are a significant share of required reserves.

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

All participants to which the three pivotal supplier (TPS) test was applied (in the RTO, BGE, and Dominion RPM markets) failed the three pivotal supplier test. The result was that offer caps were applied to all sell offers for Existing Generation Capacity Resources when the capacity market seller did not pass the test, the submitted sell offer exceeded the tariff defined offer cap, and the submitted sell offer, absent mitigation, would have resulted in a higher market clearing price.^{35 36}

The correct definition of a competitive offer in the capacity market 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 rational capacity market nonperformance penalties, and the relevant costs of acquiring fuel, including natural gas.

The MMU recommends elimination of the key remaining components of the CP model because they interfere with competitive outcomes in the capacity market and create unnecessary complexity and risk. The use of Net CONE as the basis for the PAI penalty rate is unsupported by economic logic. The use of Net CONE to establish penalties is a form of arbitrary administrative pricing that creates arbitrarily high risk for generators, creates an artificial rationale for not offering intermittent and storage resources, creates complexity in the calculation of CPQR, and ultimately raises the price of capacity above the competitive level.

³⁵ Prior to November 1, 2009, existing DR and EE were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 (2009) at P 30.

³⁶ 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).

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 during Winter Storm Elliott 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 $B * ELCC$ accredited UCAP factor for a unit, where B is the balancing ratio and ELCC accredited UCAP factor is the derating factor. For example, if B were 80 percent, the actual required performance for a unit with an 80 percent ELCC accredited UCAP factor would be only 64 percent of ICAP ($.80 * .80$). For units with low ELCC accredited UCAP factors, the required performance is even lower. The obligation to perform should equal the full ICAP value of a unit, consistent with the associated must offer obligation in the energy market for capacity resources.

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

The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.^{37 38 39 40 41 42 43 44 45 46 47} In the first nine 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. A majority of capacity investments in PJM were financed by market sources. Of the 55,064.5 MW of additional capacity that cleared in RPM auctions for the 2007/2008 through 2023/2024 Delivery Years, 42,444.9 MW (77.1 percent) were based on market funding. Of the 9,092.0 MW of additional capacity that cleared in RPM auctions for the 2024/2025 and 2025/2026 Delivery Year, 5,641.6 MW (62.5 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.

37 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).

38 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).

39 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).

40 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).

41 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).

42 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).

43 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).

44 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).

45 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).

46 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part A," <https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_A_20240920.pdf> (September 20, 2024).

47 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part B," <https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_B_20241015.pdf> (October 15, 2024).

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.

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

Date	Name
January 12, 2024	IMM Answer to PJM Answer re PJM CFP 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 CFP 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 CFP 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
April 3, 2024	EE Addback Education https://www.monitoringanalytics.com/reports/Presentations/2024/IMM_MIC_EE_Addback_Education_20240403.pdf
April 18, 2024	IMM Determinations Posted for the PJM 2025/2026 RPM Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Determinations_Posted_for_the_PJM_%202025-2026_Base_Residual_Auction-Revised_20240418.pdf
May 31, 2024	IMM Complaint re Indicated EE Sellers Docket No. EL24-113 https://www.monitoringanalytics.com/filings/2024/IMM_Complaint_Docket_No_EL24-113_20240530.pdf
June 14, 2024	IMM Answer re IMM Complaint EE Suppliers Docket No. EL24-113 https://www.monitoringanalytics.com/filings/2024/IMM_Answer_to_Motion_Docket_No_EL24-113_20240614.pdf
June 25, 2024	IMM Answer re Elwood Waiver Request Docket No. ER24-2176 https://www.monitoringanalytics.com/filings/2024/IMM_Answer_Opposing_Elwood_Waiver_Request_Docket_No_ER24-2176_20240625.pdf
June 25, 2024	IMM Answer re Elgin Waiver Request Docket No. ER24-2173 https://www.monitoringanalytics.com/filings/2024/IMM_Answer_Opposing_Elgin_Waiver_Request_ER24-2173_20240625.pdf
June 28, 2024	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2025/2026 Delivery Year (PDF) https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Notice_re_RPM_Must_Offer_Obligations_20240628.pdf
July 3, 2024	MMU Calculated Net Revenues for the 2026/2027 RPM Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Calculated_Net_Revenues_2026-2027_Base_Residual_Auction_20240703.pdf
July 8, 2024	Data Submission Window Opening for the 2026/2027 RPM Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Opening_2026-2027_Base_Residual_Auction_20240708.pdf
July 10, 2024	IMM Complaint re EE Payment Docket No. EL24-126 https://www.monitoringanalytics.com/filings/2024/IMM_Complaint_Docket_No_EL24-xxx_20240710.pdf
July 10, 2024	IMM Comments re JCA EE Complaint Docket No. EL24-118 https://www.monitoringanalytics.com/filings/2024/IMM_Comments_Docket_No_EL24-118_20240710.pdf
July 10, 2024	IMM EE Package Proposal https://www.monitoringanalytics.com/reports/Presentations/2024/IMM_MIC_EE_Package_Proposal_20240710.pdf
July 16, 2024	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2025/2026 Delivery Year (PDF) https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Notice_re_RPM_Must_Offer_Obligations_20240716.pdf
July 24, 2024	IMM EE Package Proposal https://www.monitoringanalytics.com/reports/Presentations/2024/IMM_MRC_EE_Package_20240724.pdf
August 6, 2024	IMM Answer and Motion for Leave to Answer re IMM Complaint EE Suppliers Docket No. EL24-113 https://www.monitoringanalytics.com/filings/2024/IMM_Answer_to_Answer_Docket_No_EL24-113_20240806.pdf
August 15, 2024	IMM Answer and Motion for Leave to Answer and Motion for Summary Disposition re EE Docket No. EL24-126 https://www.monitoringanalytics.com/filings/2024/IMM_Answer_to_Answer_Docket_No_EL24-126_20240815.pdf
August 20, 2024	IMM Answer and Motion for Leave to Answer re CPower EE Complaint Docket No. EL24-128 https://www.monitoringanalytics.com/filings/2024/IMM_Answer_to_PJM_Answer_Docket_No_EL24-128_20240820.pdf
September 5, 2024	IMM Determinations Posted for the PJM 2026/2027 RPM Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Determinations_Posted_for_the_PJM_2026-2027_Base_Residual_Auction_20240905.pdf
September 20, 2024	Analysis of the 2025/2026 RPM Base Residual Auction - Part A https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_A_20240920.pdf
September 27, 2024	Data Submission Window Opening for the 2025/2026 RPM Third Incremental Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Opening_2025-2026_Third_Incremental_Auction_20240927.pdf
September 27, 2024	IMM Comments re EE Resources in the Capacity Market Docket No. ER24-2995 https://www.monitoringanalytics.com/filings/2024/IMM_Comments_re_PJM_EE_Filing_Docket_No_ER24-2995_20240927.pdf
September 30, 2024	IMM Partial Offer of Settlement re EE Payments Complaint Docket No. EL24-113 https://www.monitoringanalytics.com/filings/2024/IMM_Offer_of_Settlement_Docket_No_EL24-113_20240930.pdf
October 10, 2024	IMM Comments re Sierra Club Complaint Docket No. EL24-148 https://www.monitoringanalytics.com/filings/2024/IMM_Comments_Docket_No_EL24-148_20241010.pdf
October 14, 2024	IMM Answer and Motion for Leave to Answer re EE Resources in the Capacity Market Docket No. ER24-2995 https://www.monitoringanalytics.com/filings/2024/IMM_Answer_to_Comments_Docket_No_ER24-2995_20241014.pdf
October 15, 2024	Analysis of the 2025/2026 RPM Base Residual Auction - Part B https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_B_20241015.pdf
October 18, 2024	IMM Comments re JCA EE Complaint Docket No. EL24-118 https://www.monitoringanalytics.com/filings/2024/IMM_Comments_Docket_No_EL24-118_20241018.pdf

Market Design

With the earlier introduction of the Capacity Performance model and the recent introduction of the ELCC model, combined with a tightening of the capacity supply and demand balance in ICAP terms, it is clear that PJM choices about the details of market design have a potentially dominant impact on capacity market outcomes in PJM.

RPM prices are locational and may vary depending on transmission constraints into LDAs and local supply and demand conditions.⁴⁸ The capacity market is not fully locational. The capacity market locational differences exist only across LDAs. The capacity market design assumes that there are no transmission or operational constraints within LDAs and treats all capacity resources within an LDA as perfect substitutes even when they are not. The lack of a fully locational design is a market design flaw that has resulted in the designation of units as RMRs based on internal constraints that were not recognized in the market clearing process. Existing generation that qualifies as a capacity resource must be offered into RPM auctions, except for categorically exempt intermittent and capacity storage resources including hydro and except for resources in a fixed resource requirement (FRR) plan. All load is required to pay for capacity. Participation by LSEs is mandatory, except for those entities that elect the FRR option. There is an administratively determined demand curve that defines scarcity pricing levels and that, with the supply curve derived from capacity offers, determines market prices in each BRA. There are explicit market power mitigation rules that define structural market power, that define offer caps based on the marginal cost of capacity, and that have flexible criteria for competitive offers by new entrants. Demand resources may be offered directly into RPM auctions and receive the clearing price without mitigation.

The results of the 2025/2026 RPM Base Residual Auction were significantly affected by flawed market design decisions including by the CP design, by PJM's ELCC approach, by the definition of the maximum VRR price as gross CONE, by the failure to extend the RPM must offer requirement to all resources, by the product definition and lack of market power mitigation for demand

⁴⁸ 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.

resources, and by the exclusion from supply of the defined RMR resources. The BRA prices do not solely reflect supply and demand fundamentals but also reflect, in significant part, PJM decisions about the definition of supply and demand. The auction results were not solely the result of the market design and do in part reflect the tightening of supply and demand conditions in the PJM Capacity Market.

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 to provide an incentive to produce energy during high demand hours that is even higher than the energy market incentive, amplified by an operating reserve demand curves (ORDC). The risk created by CP is not limited to risk for individual generators, but extends to the viability of the market. If penalties create bankruptcies that threaten the viability of required energy output from the affected units, there is a risk to the market.

The CP PAI incentives are not effective market incentives. PAI incentives are administrative and nonmarket incentives that are not compatible with an effective market design. The energy market clearing, in contrast, is transparent and efficient and timely. While there are issues with the details of energy market pricing that must be addressed, including shortage pricing, the energy market does not include or create the significant and long lasting uncertainty created by the PAI rules as exhibited most dramatically by the results of Winter Storm Elliott. The PAI design creates an administrative

process that adds unacceptable uncertainty to the process and that can never approach the effectiveness of the energy market in providing price signals and timely settlement. In addition, the imposition of PAI penalties on intermittent resources when those resources cannot perform is a key reason for the failure to apply the RPM must offer requirement uniformly.

In order to more accurately reflect resources' reliability contributions, ELCC should be significantly refined to include hourly data that would permit integrated unit specific ELCC ratings, to weight summer and winter risk in a more balanced manner, and CP should be modified to eliminate PAI risks, and to pay for actual hourly performance rather than based on relatively inflexible class capacity accreditation ratings derived from a small number of hours of poor performance. In the short run capacity accreditation should recognize the winter capability of thermal resources rather than limiting such resources to summer ratings. Most of the risk recognized in the ELCC model is winter risk but the ELCC accreditation values for thermal resources are capped at the summer ratings. That unnecessarily limits supply and changes the ELCC values for all other resources and changes the system accredited unforced capacity and therefore AUCAP, the maximum level of load that can be served by the existing resources and therefore the reliability requirement. The CIRs of such resources are currently limited by the summer ratings but those rules can and should be changed given the use of the ELCC approach. There is no reason that excess winter CIRs cannot be assigned to these resources immediately.

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

in the capacity market. Net CONE was the equilibrating factor between the capacity market and energy market. The use of Gross CONE is inconsistent with that basic capacity market logic. Gross CONE was introduced as the maximum price based on concerns that Net CONE would be too low. The maximum point on the VRR curve for the 2025/2026 BRA was the higher of Gross CONE or 1.5 times Net CONE and Gross CONE was used. However, if the logic of the markets implies a low Net CONE, that is the right answer. There is nothing inherently wrong with a low Net CONE that requires abandoning the basic capacity market logic. Gross CONE was an intervention designed to increase capacity market prices despite the fact that the basic economic logic did not support that increase. If there is an issue with the calculation of Net CONE, it should be addressed directly rather than by ignoring its central role in the design of the capacity market.

Currently, intermittent and storage capacity resources are exempt from the RPM must offer requirement. In the 2025/2026 BRA, the sum of cleared MW that were considered categorically exempt from the must offer requirement is 8,233.5 MW, or 40.9 percent of the required reserves and 39.2 percent of total reserves. Demand resources are also exempt from the RPM must offer requirement. Yet such resources combined make up more than two thirds (68.1 percent) of PJM's reserves. Given the growth of such resources and the expected growth based on the interconnection queue, that exemption should be eliminated immediately. The fact that more than two thirds of the PJM reserves depend on resources that are not subject to the RPM must offer requirement means that reliability is significantly less certain than the stated reserve margins indicate. Prior to the implementation of the capacity performance design, all existing capacity resources, except DR, were subject to the RPM must offer requirement. There is no reason to exempt intermittent and capacity storage resources, including hydro, from the RPM must offer requirement. The same rules should apply to all capacity resources. The purpose of the RPM must offer rule, which has been in place since the beginning of the capacity market in 1999, is to ensure that the capacity market works, and therefore that the energy market works, based on the inclusion of all demand and all supply, to ensure competitive entry, to ensure open access to the transmission system, and to prevent the exercise of market

power via withholding of capacity supply. The purpose of the RPM must offer requirement is also to ensure equal access to the transmission system through CIRs (capacity interconnection rights).

If some capacity resources hold CIRs that provide the 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. That conclusion does not depend on whether withholding directly benefits those resources through a portfolio effect. The result of the failure to offer can be a significant increase in the market price of capacity above the competitive level when that supply is pivotal. The result of the failure to offer was a significant increase in the market price of capacity above the competitive level in the 2025/2026 BRA.

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 capacity resources. The failure to apply the RPM 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 capacity resources increases. The failure to apply the RPM 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.

Consistent with the must offer obligation, performance penalties should not be applied to solar and wind resources when they are not capable of performing based on ambient conditions. For example, solar resources should be subject to performance penalties if they fail to perform when the sun is shining but should not be subject to performance penalties in the middle of the night. If PAI is retained, this would be a rational application of the PAI

penalties that recognizes the physical capabilities of resources and is therefore not discriminatory.

Demand resources (DR) have always been treated more favorably than generation capacity resources. Demand resources do not have an RPM must offer requirement. Demand resources, unlike all other capacity resources, are not subject to market seller offer caps to protect against the exercise of market power. When demand resources are pivotal, as they were for the 2025/2026 BRA, they have structural market power and can and do exercise market power. That conclusion does not depend on whether withholding directly benefits those resources through a portfolio effect. The result of the failure to offer can be a significant increase in the market price of capacity above the competitive level when that supply is pivotal. If the resources clear, it benefits the resources directly. Even if the resources do not clear, higher prices can benefit the owners of capacity portfolios that include such resources as well as resources with an RPM must offer requirement. The MMU recommends that demand resources have defined and enforced market seller offer caps, like all other capacity resources.

Installed Capacity

On January 1, 2024, RPM installed capacity was 178,375.0 MW (Table 5-3).⁴⁹ Over the next nine months, new generation, unit deactivations, facility reratings, plus import and export shifts resulted in RPM installed capacity of 177,032.4 MW on September 30, 2024, a decrease of 1,342.6 MW or 0.8 percent from the January 1 level.^{50 51} The 1,342.6 MW decrease was the net result of derates (2,500.9 MW) and deactivations or changes in capacity resource status (679.9 MW), partially offset by new or reactivated generation (1,206.5 MW), net capacity modifications (548.6 MW), decreases in exports (66.0 MW), and increases in imports (17.1 MW).

At the beginning of the new delivery year on June 1, 2024, RPM installed capacity was 176,985.3 MW, an increase of 365.6 MW or 0.0 percent from the May 31, 2023, level of 176,619.7 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.

⁴⁹ 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.

⁵⁰ 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.

⁵¹ Wind resources accounted for 3,321.4 MW, and solar resources accounted for 3,603.3 MW of installed capacity in PJM on January 1, 2024. 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 to be calculated using actual data. There are additional wind and solar resources not reflected in total capacity because they are energy only resources and do not participate in the PJM Capacity Market. See "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," Appendix B.3 Calculation Procedure, Rev. 19 (June 27, 2024). The derating approach has been replaced with ELCC starting in the 2023/2024 Delivery Year.

Table 5-3 Installed capacity (By fuel source): January 1, May 31, June 1, and September 30, 2024⁵²

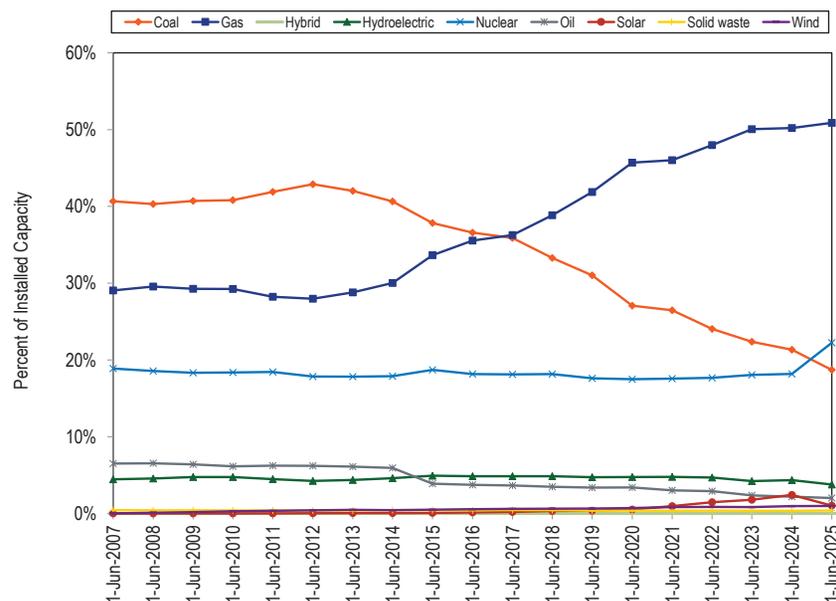
	01-Jan-24		31-May-24		01-Jun-24		30-Sep-24	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Battery	21.9	0.0%	21.9	0.0%	21.5	0.0%	21.5	0.0%
Coal	37,936.3	21.3%	38,013.1	21.5%	37,751.4	21.3%	37,894.5	21.4%
Gas	88,868.7	49.8%	88,815.5	50.3%	88,860.7	50.2%	88,743.2	50.1%
Hybrid	10.2	0.0%	10.2	0.0%	9.3	0.0%	9.3	0.0%
Hydroelectric	7,507.2	4.2%	7,507.2	4.3%	7,673.1	4.3%	7,673.1	4.3%
Nuclear	32,183.0	18.0%	32,180.5	18.2%	32,180.5	18.2%	32,179.9	18.2%
Oil	4,295.6	2.4%	4,184.4	2.4%	3,865.1	2.2%	3,822.1	2.2%
Solar	3,603.3	2.0%	3,780.6	2.1%	4,279.2	2.4%	4,362.3	2.5%
Solid waste	627.4	0.4%	627.4	0.4%	627.4	0.4%	609.4	0.3%
Wind	3,321.4	1.9%	1,478.9	0.8%	1,717.1	1.0%	1,717.1	1.0%
Total	178,375.0	100.0%	176,619.7	100.0%	176,985.3	100.0%	177,032.4	100.0%

Figure 5-1 shows the share of installed capacity by fuel source for the first day of each delivery year, from June 1, 2007, to June 1, 2024, as well as the expected installed capacity for the 2025/2026 Delivery Year, based on the results of all auctions held through September 30, 2024.⁵³ On June 1, 2007, coal comprised 40.7 percent of the installed capacity, reached a maximum of 42.9 percent in 2012, decreased to 21.3 percent on June 1, 2024, and is expected to decrease to 18.7 percent on June 1, 2025. The share of gas increased from 29.1 percent on June 1, 2007, to 50.2 percent on June 1, 2024, and is expected to increase to 50.9 percent on June 1, 2025.

⁵² The data for hybrid solar/battery resources are included in the solar data for confidentiality reasons.

⁵³ Due to EFORd values not being finalized for future delivery years, the expected installed capacity is based on cleared unforced capacity (UCAP) MW using the EFORd submitted with the offer.

Figure 5-1 Percent of installed capacity (By fuel source): June 1, 2007 through June 1, 2025



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 September 30, 2024, by funding type.

Table 5-5 Installed capacity by funding type: January 1, May 31, June 1, and September 30, 2024

Funding Type	01-Jan-24		31-May-24		01-Jun-24		30-Sep-24	
	ICAP (MW)	Percent of Total ICAP						
Market	131,927.9	74.0%	130,513.7	73.9%	129,265.9	73.0%	129,260.1	73.0%
Nonmarket	46,447.1	26.0%	46,106.0	26.1%	47,723.1	27.0%	47,772.3	27.0%
Total	178,375.0	100.0%	176,619.7	100.0%	176,989.0	100.0%	177,032.4	100.0%

Table 5-4 shows the RPM installed capacity on January 1, 2024, through September 30, 2024, for the top five generation capacity resource owners, excluding FRR committed MW.

Table 5-4 Installed capacity by parent company: January 1, May 31, June 1, and September 30, 2024

Parent Company	01-Jan-24			31-May-24			01-Jun-24			30-Sep-24		
	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	20,175.1	14.0%	1	20,137.0	14.1%	1	20,136.7	14.1%	1
ArLight Capital Partners, LLC	12,115.2	8.3%	2	10,770.9	7.5%	3	10,521.1	7.4%	3	10,521.1	7.4%	4
LS Power Group	11,486.7	7.9%	3	11,485.7	8.0%	2	11,873.4	8.3%	2	12,691.6	8.9%	2
Teachers Insurance and Annuity Association of America	10,167.9	7.0%	4	10,167.9	7.1%	4	10,169.2	7.1%	4	10,169.2	7.1%	5
Vistra Energy Corp.	8,669.4	6.0%	5	8,289.3	5.8%	5	8,177.1	5.7%	5	11,748.5	8.2%	3

Fuel Diversity

Figure 5-2 shows the fuel diversity index (FDI_c) for RPM installed capacity.⁵⁴ 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.⁵⁵ The reduction in the FDI_c resulted from an increase in coal capacity resources. A similar but more significant reduction occurred in 2004 with the expansion into the COMED, AEP, and DAY Control Zones.⁵⁶ The average FDI_c for the first nine months of 2024 decreased 0.7 percent compared to the first nine months of 2023. Figure 5-2 also includes the expected FDI_c through September 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.⁵⁷ The dotted green line in Figure 5-2 shows the FDI_c assuming that the capacity

54 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.

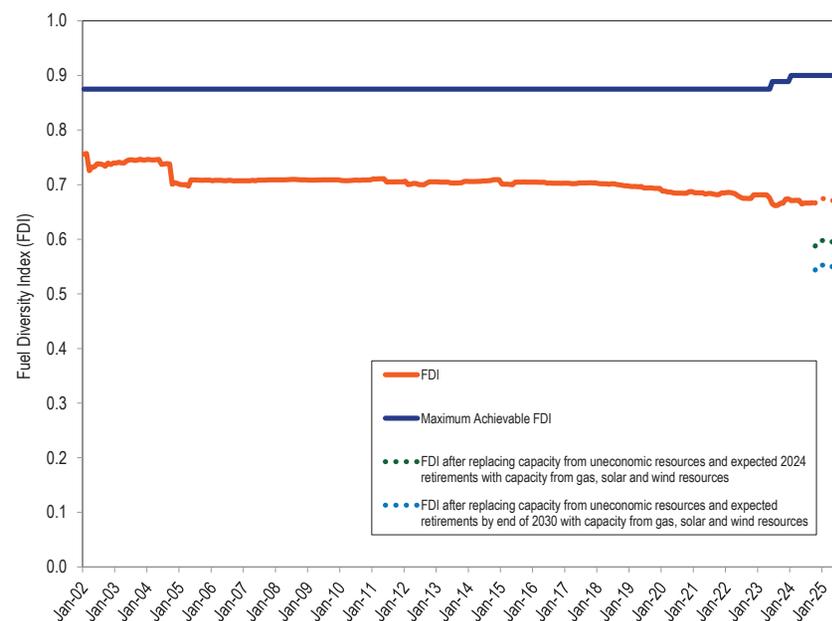
55 On April 1, 2002, the PJM Region expanded with the addition of Allegheny Power System under a set of agreements known as "PJM-West." See page 4 in the 2002 Annual State of the Market Report for PJM for additional details.

56 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.

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

from the expected 2024 retirements were replaced by gas, wind and solar capacity.⁵⁸ The FDI_c under these assumptions would have been 11.2 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.⁵⁹ The counterfactual FDI_c in this scenario is 17.7 percent lower than the actual FDI_c.

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



58 It is assumed that 654.8 MW of replacement capacity is from solar units and 639.8 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 9,426.2 GWh of generation in the first nine months of 2024 assuming the applicable PJM ELCC capacity derate factors 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 nine months of 2024. The split between solar and wind is based on queue data.

59 It is assumed that 2,885.5 MW of replacement capacity is from solar units and 2,953.3 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 42,511.7 GWh of generation in 2030 assuming the applicable PJM ELCC capacity derate factors 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 nine 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.⁶⁰ In the first nine months of 2024, the 2024/2025 RPM Third Incremental Auction and the 2025/2026 RPM Base Residual Auction were 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. Based on the FERC Order in Docket No. ER23-729-002, PJM reran the 2024/2025 RPM Base Residual Auction with final results posted on May 6, 2024, and PJM reran the 2024/2025 Third Incremental Auction with final results posted on May 23, 2024.⁶¹ The 2025/2026 RPM Base Residual Auction was conducted in July 2024.

Market Structure

Supply

Table 5-6 shows generation capacity changes since the implementation of the Reliability Pricing Model through the 2023/2024 Delivery Year. The 12,960.3 MW increase was the result of new generation capacity resources (44,766.8 MW), reactivated generation capacity resources (1,380.4 MW), uprates (8,917.3 MW), integration of external zones (21,967.5 MW), a net decrease in capacity exports (750.9 MW), offset by a net decrease in capacity imports (1,530.2 MW), deactivations (57,779.3 MW) and derates (5,513.1 MW).

⁶⁰ See Letter Order, Docket No. ER10-366-000 (January 22, 2010).
⁶¹ 187 FERC ¶ 61,065 (2024).

Table 5-7 shows the calculated RPM reserve margin and reserve in excess of the defined installed reserve margin (IRM) for June 1, 2021, through June 1, 2025, 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.

Future Changes in Generation Capacity⁶²

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 2023/2024 Delivery Year, internal installed capacity decreased by 8,227.9 MW after accounting for new capacity resources, reactivations, and uprates (55,064.5 MW) and capacity deactivations and derates (63,292.4 MW).

For the current and future delivery years (2024/2025 through 2025/2026), 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 (3,141.4 MW) and pending deactivations (2,499.2 MW), PJM capacity is expected to increase by 642.2 MW through the 2025/2026 Delivery Year.

⁶² 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 2023/2024⁶³

	ICAP (MW)									
	New	Reactivations	Upgrades	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)	
2023/2024	2,696.8	0.0	510.5	0.0	(47.9)	1,067.8	5,149.2	1,441.1	(4,498.7)	
Total	44,766.8	1,380.4	8,917.3	21,967.5	(1,530.2)	(750.9)	57,779.3	5,513.1	12,960.3	

As shown in Table 5-7, based on current positions, total reserves on June 1, 2025, will be 21,015.2 MW, of which 870.9 MW (UCAP) are in excess of the required level of reserves, which is 20,144.3 MW (UCAP). In the 2025/2026 BRA, 13,143.2 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 3,745.8 MW of intermittent and storage resources (28.5 percent of the categorically exempt MW and 2.8 percent of total cleared MW) were not offered in the 2025/2026 BRA.

In the 2025/2026 BRA, the sum of cleared MW that were considered categorically exempt from the must offer requirement is 8,233.5 MW, or 40.9 percent of the required reserves and 39.2 percent of total reserves. The cleared MW of DR is 6,085.6 MW, or 30.2 percent of required reserves and 29.0 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 14,319.1 MW, or 71.1 percent of required reserves and 68.1 percent of total reserves.

The fact that more than two thirds (68.1 percent) of the PJM reserves depend on resources that are not subject to the RPM must offer requirement, a core part of the capacity market design, means that reliability is significantly less certain than the stated reserve margins indicate.

⁶³ The capacity changes in this report are calculated based on June 1 through May 31.

Table 5-7 RPM reserve margin: June 1, 2021, to June 1, 2025^{64 65}

	01-Jun-21	01-Jun-22	01-Jun-23	01-Jun-24	01-Jun-25	
Forecast peak load ICAP (MW)	149,482.9	149,263.6	149,382.2	151,631.1	153,883.0	A
FRR peak load ICAP (MW)	11,717.7	28,292.8	29,554.6	30,431.0	11,597.3	B
PRD ICAP (MW)	510.0	230.0	235.0	305.0	224.0	C
Installed reserve margin (IRM)	14.7%	14.9%	14.9%	17.7%	17.8%	D
Pool wide average EFORD	5.22%	5.08%	4.87%	5.10%		E
Pool wide accredited UCAP factor					79.69%	F
Forecast pool requirement (FPR)	1.087	1.091	1.093	1.117	0.939	$G=(1+D)*(1-E)$ or $G=(1+D)*F$
RPM committed less deficiency UCAP (MW) (generation and DR)	156,633.6	137,944.8	136,408.5	138,324.8	134,224.2	H
RPM committed less deficiency ICAP (MW) (generation and DR)	165,260.2	145,327.4	143,391.7	145,758.5	168,432.9	$J=H/(1-E)$ or $J=H/F$
RPM peak load ICAP (MW)	137,255.2	120,740.8	119,592.6	120,895.1	142,061.7	$K=A-B-C$
Reserve margin ICAP (MW)	28,005.0	24,586.6	23,799.1	24,863.4	26,371.2	$L=J-K$
Reserve margin (%)	20.4%	20.4%	19.9%	20.6%	18.6%	$M=L/K$
Reserve margin in excess of IRM ICAP (MW)	7,828.5	6,596.3	5,979.8	3,465.0	1,084.2	$N=L-D*K$
Reserve margin in excess of IRM (%)	5.7%	5.5%	5.0%	2.9%	0.8%	$P=N/K$
RPM peak load UCAP (MW)	130,090.5	114,607.2	113,768.4	114,729.4	113,209.0	$Q=K*(1-E)$ or $Q=K*F$
RPM reliability requirement UCAP (MW)	149,210.1	131,679.9	130,714.7	135,039.8	133,353.3	$R=K*G$
Reserve margin UCAP (MW)	26,543.1	23,337.6	22,640.1	23,595.4	21,015.2	$S=H-Q$
Reserve cleared in excess of IRM UCAP (MW)	7,423.5	6,264.9	5,693.8	3,285.0	870.9	$T=H-R$
Projected replacement capacity UCAP (MW)	0.0	0.0	0.0	0.0	0.0	U
Projected reserve margin	20.4%	20.4%	19.9%	20.6%	18.6%	$V=(J-U)/(1-E)/K-1$ or $V=(J-U/F)/K-1$

Sources of Funding⁶⁶

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 2023/2024 Delivery Year totaled 46,147.2 MW (83.8 percent of all additions), with 36,021.6 MW from market funding and 10,135.6 MW from nonmarket funding. Upgrades to existing generation capacity from the 2007/2008 Delivery Year through the 2023/2024 Delivery Year totaled 8,917.3 MW (16.2 percent of all additions), with 2,494.0 MW from market funding and 2,494.0 MW from nonmarket funding. In summary, of the 55,064.5 MW of additional capacity from new, reactivated, and upgraded generation that cleared in RPM auctions for the 2007/2008 through 2023/2024 Delivery Years, 42,444.9 MW (77.1 percent) were based on market funding.

Of the 9,092.0 MW of the additional generation capacity (new resources, reactivated resources, and upgrades) that cleared in RPM auctions for the 2024/2025 and 2025/2026 Delivery Years, 4,234.2 MW are not yet in service. Of those 4,234.2 MW that have not yet gone into service, 3,123.8 MW have market funding and 1,110.4 MW have nonmarket funding. Applying the historical completion rates, 65.5 percent of all the projects in development are expected to go into service (2,041.0 MW of the 4,234.2 MW of in development market funded projects; 734.0 MW of the 1,110.4 MW in development nonmarket funded projects).⁶⁷

⁶⁴ 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.

⁶⁵ These reserve margin calculations do not consider Fixed Resource Requirement (FRR) load.

⁶⁶ 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).

⁶⁷ See the 2023 Annual State of the Market Report for PJM, Volume II, Section 12: Generation and Transmission Planning.

Of the 4,857.8 MW of the additional generation capacity that cleared in RPM auctions for the 2024/2025 and 2025/2026 Delivery Years and are already in service, 2,517.8 MW (51.8 percent) are based on market funding and 2,340.0 MW (48.2 percent) are based on nonmarket funding.

In summary, 5,641.6 MW (62.1 percent) of the additional generation capacity (3,123.8 MW not yet in service and 2,517.8 MW in service) that cleared in RPM auctions for the 2024/2025 and 2025/2026 Delivery Years are based on market funding. Capacity additions based on nonmarket funding are 3,450.4 MW (38.0 percent) of proposed generation that cleared the RPM auctions for the 2024/2025 and 2025/2026 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.

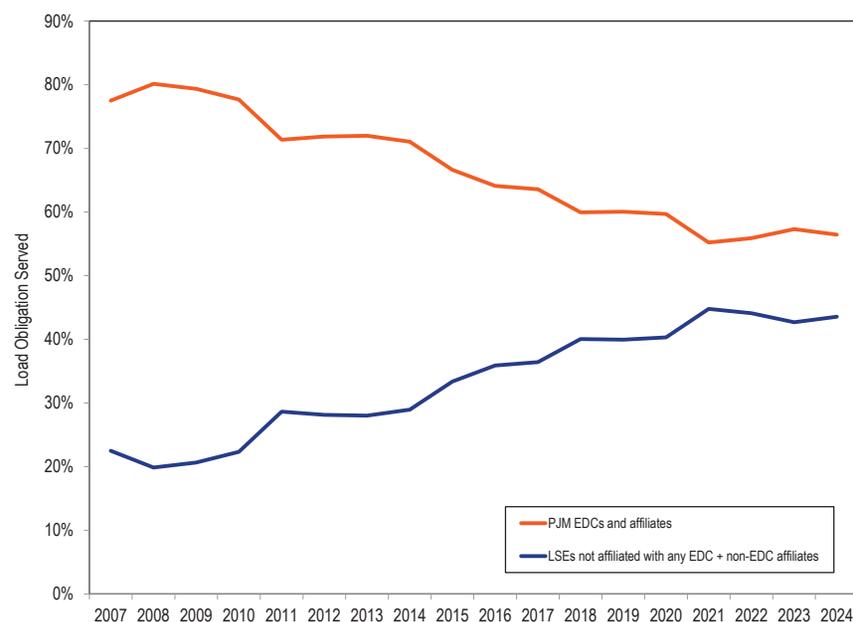
On June 1, 2024, PJM EDCs and their affiliates maintained a majority market share of load obligations under RPM, together totaling 56.4 percent (Table 5-8), down from 57.3 percent on June 1, 2023. The combined market share of LSEs not affiliated with any EDC and of non-PJM EDC affiliates was 43.6 percent, up from 42.7 percent on June 1, 2023. 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, 2024, 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 56.4 percent on June 1, 2024. 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 43.6 percent on June 1, 2024.⁶⁸

Table 5-8 Capacity market load obligation served: June 1, 2023 and June 1, 2024

	01-Jun-23		01-Jun-24		Change	
	Obligation (MW)	Percent of total obligation	Obligation (MW)	Percent of total obligation	Obligation (MW)	Percent of total obligation
PJM EDCs and Affiliates	101,469.1	57.3%	106,462.1	56.4%	4,993.0	(0.9%)
LSEs not affiliated with any EDC + non EDC Affiliates	75,548.7	42.7%	82,180.1	43.6%	6,631.5	0.9%
Total	177,017.7	100.0%	188,642.2	100.0%	11,624.5	0.0%

⁶⁸ Prior to the 2012/2013 Delivery Year, obligation was defined as cleared and make whole MW in the Base Residual Auction and the Second Incremental Auction plus ILR forecast obligations. Effective with the 2012/2013 Delivery Year, obligation is defined as the sum of the unforced capacity obligations satisfied through all RPM auctions for the delivery year.

Figure 5-3 Capacity market load obligation served: June 1, 2007 through June 1, 2024



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 than it would be if the actual auction clearing MW were used.

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

The CTR issue implies a broader issue with capacity market clearing and settlements. The capacity market is cleared based on a three year ahead forecast of load and offers of capacity. Payments to capacity resources in the delivery year are based on the capacity market clearing prices and quantities. But payments by customers in the delivery year are not based on market clearing prices and quantities. Payments by customers in each zone are based on the

ratio of zonal forecast peak load to the RTO forecast peak load used for the Third Incremental Auction, run three months prior to the delivery year when auctions follow the traditional schedule.⁶⁹ The allocation sometimes creates significant differences between the capacity cleared to meet the reliability requirement and the capacity obligation allocated to the customers in a zone. For example, ComEd Zone, which is identical to ComEd LDA, cleared 27,932.1 MW including 5,574.0 MW of imports in the 2021/2022 RPM BRA. The ComEd Zone's capacity obligation, immediately after the clearing of the Base Residual Auction was 24,983.0 MW. The final ComEd Zone's capacity obligation for the 2021/2022 Delivery Year after the Third Incremental Auction was 22,721.2 MW.

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

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

In the 2025/2026 RPM Base Residual Auction, BGE had 4,990.0 MW of CTRs with a total value of \$357.8 million and DOM had 1,903.3 MW of CTRs with a total value of 121.1 million.

BGE had 65.7 MW of customer funded ICTRs with a total value of \$4.7 million.

BGE had 306.0 MW of ICTRs due to Incremental Rights-Eligible Required Transmission Enhancements with a value of 21.9 million.

⁶⁹ See "PJM Manual 18: PJM Capacity Market," § 7.2.3 Final Zonal Unforced Capacity Obligations, Rev. 59 (June 27, 2024).

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.⁷⁰ Figure 5-4 shows the shape of the VRR curve for the 2025/2026 RPM Base Residual Auction.

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

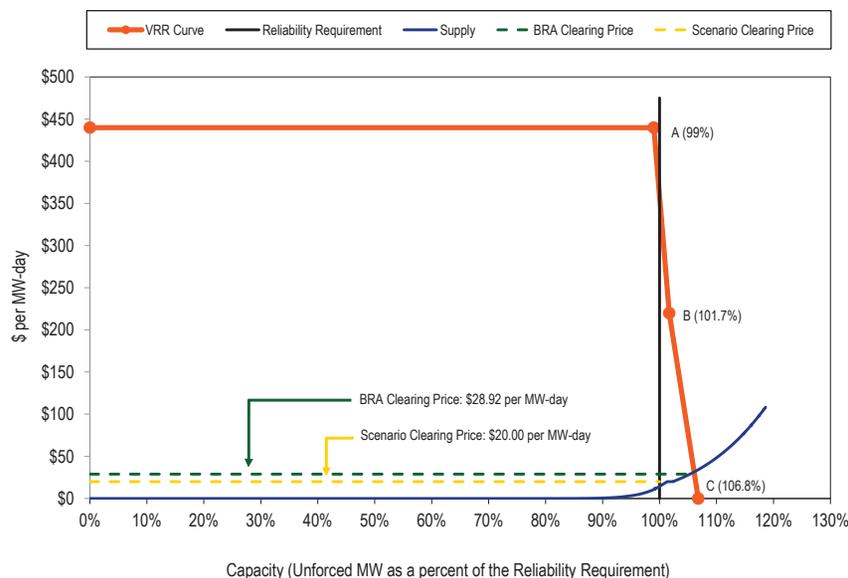
Effective for the 2018/2019 and subsequent delivery years, PJM revised the VRR curve.⁷¹ PJM defines the reliability requirement as the capacity needed to satisfy the one event in 10 years loss of load expectation (LOLE) for the RTO and capacity needed to satisfy the one event in 25 years loss of load 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).

⁷⁰ The formula for the MW level where the VRR curve begins the downward slope is given by $(Reliability\ Requirement) \times [1 - 1.2\% / (Installed\ Reserve\ Margin)]$.

⁷¹ "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-curve-report.ashx?la=en>>.

Figure 5-4 shows the RTO VRR curve and RTO reliability requirement for the 2025/2026 RPM BRA.

Figure 5-4 Shape of the VRR curve relative to the reliability requirement: 2025/2026 Delivery Year



Market Concentration

Auction Market Structure

As shown in Table 5-9, in the 2024/2025 RPM Third Incremental Auction and the 2025/2026 RPM Base Residual Auction all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.⁷² 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,

⁷² 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.

the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.^{73 74 75}

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.

⁷³ See OATT Attachment DD § 6.5.

⁷⁴ 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).

⁷⁵ 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: 2022/2023 through 2025/2026 RPM Auctions⁷⁶

RPM Markets	RSI _{1,105}	RSI ₃	Total Participants	Failed RSI ₃ Participants
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	0.88	0.59	64	64
MAAC	0.60	0.17	10	10
EMAAC	0.00	0.00	1	1
BGE	0.00	0.00	1	1
2025/2026 Base Residual Auction				
RTO	0.82	0.62	128	128
BGE	0.00	0.00	0	0
Dominion	0.00	0.00	0	0

76 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.⁷⁷ 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.”⁷⁸ 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.⁷⁹ ⁸⁰ 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

77 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.

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

79 146 FERC ¶ 61,052 (2014).

80 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)”.

UCAP transactions, and/or are not designated as a replacement resource, are eligible to export their capacity from PJM.⁸¹

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 derive 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

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.⁸²

Effective May 9, 2017, significantly improved pseudo tie requirements for external generation capacity resources were implemented.⁸³ 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.^{84 85 86} 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

⁸² 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).

⁸³ 161 FERC ¶ 61,197 (2017).

⁸⁴ See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 9 & 10.

⁸⁵ "PJM Manual 18: PJM Capacity Market," § 4.2.2 Existing Generation Capacity Resources – External, Rev. 59 (June 27, 2024).

⁸⁶ "PJM Manual 18: PJM Capacity Market," § 4.6.4 Importing an External Generation Resource, Rev. 59 (June 27, 2024).

⁸¹ OATT Attachment DD § 5.6.6(b).

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.⁸⁷

Planned External Generation Capacity Resources are eligible to be offered into an RPM Auction if they meet specific requirements.^{88 89} 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.⁹⁰ 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.⁹¹

⁸⁷ OATT Schedule 1 § 1.10.1A.

⁸⁸ See "Reliability Assurance Agreement among Load Serving Entities in the PJM Region," Section 1.69A.

⁸⁹ "PJM Manual 18: PJM Capacity Market," § 4.2.4 Planned Generation Capacity Resources – External, Rev. 59 (June 27, 2024).

⁹⁰ 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).

⁹¹ 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 1,268.5 MW of imports offered in the 2025/2026 RPM Base Residual Auction, 1,268.5 MW cleared. Of the cleared imports, 700.5 MW (55.2 percent) were from MISO.

Table 5-10 RPM imports: 2007/2008 through 2025/2026 RPM Base Residual Auctions

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

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.⁹² If DR displaces new generation resources in BRAs, but then buys out of the position prior to the

⁹² 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).

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.

Effective with the 2020/2021 Delivery Year, DR includes annual and summer products. Annual Demand Resources are required to be available on any day during the delivery year for an unlimited number of interruptions between the hours of 10:00 a.m. and 10:00 p.m. EPT for the months of June through October and the following May and between the hours of 6:00 a.m. and 9:00 p.m. EPT for the months of November through April unless there is a PJM approved maintenance outage during the October through April period.

Summer-Period Demand Resources are required to be available on any day from June through October and the following May of the delivery year for an unlimited number of interruptions between the hours of 10:00 a.m. to 10:00 p.m. EPT.

As shown in Table 5-11 and Table 5-12 committed DR was 7,699.9 MW for June 1, 2024, as a result of cleared capacity for demand resources in RPM auctions for the 2024/2025 Delivery Year (8,064.7 MW) less replacement capacity (364.8 MW).

Table 5-11 RPM load management statistics by LDA: June 1, 2021 to June 1, 2025^{93 94 95 96}

		UCAP (MW)															
		RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepeco	ATSI	ATSI Cleveland	ComEd	BGE	PPL	DAY	DEOK	Dominion
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	8,064.7	2,497.6	1,004.0	358.5	46.0	285.7	98.2	160.4	682.6	141.6	1,554.0	198.1	603.4	192.9	221.9	
	EE cleared	7,716.0	3,543.5	2,064.9	787.4	99.9	802.9	392.0	398.9	587.6	54.9	1,063.4	388.5	391.4	128.3	188.1	
	DR net replacements	(364.8)	(197.4)	9.1	43.0	35.2	(7.3)	(14.9)	19.3	50.9	(58.3)	(56.0)	23.7	(138.9)	(6.2)	(5.4)	
	EE net replacements	(48.0)	(43.6)	(15.4)	21.3	14.1	(6.5)	(0.1)	9.1	(30.6)	0.0	1.2	12.2	(38.4)	(5.6)	(3.7)	
	RPM load management	15,367.9	5,800.1	3,062.6	1,210.2	195.2	1,074.8	475.2	587.7	1,290.5	138.2	2,562.6	622.5	817.5	309.4	400.9	
01-Jun-25	DR cleared	6,064.7	1,844.9	782.7	295.5	65.0	228.9	65.8	132.5	546.1	67.3	1,086.9	163.0	422.5	140.1	159.6	673.5
	EE cleared	1,459.8	647.1	410.1	151.8	24.0	167.2	88.4	80.0	68.5	6.6	337.6	71.8	45.7	18.5	24.9	154.2
	DR net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	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	0.0
	RPM load management	7,524.5	2,492.0	1,192.8	447.3	89.0	396.1	154.2	212.5	614.6	73.9	1,424.5	234.8	468.2	158.6	184.5	827.7

93 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.

94 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.

95 EE resources are fully reflected in PJM load forecasts starting with the 2016 load forecast for the 2019/2020 Delivery Year, and EE resources are not defined to be capacity resources in any way as a result. EE resources do not clear in the capacity auctions.

96 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, 2025^{97 98 99}

	UCAP (MW)						Registered DR		
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM	RPM Commitments	ICAP (MW)	UCAP Conversion Factor	UCAP (MW)
					Commitment Shortage	Less Commitment Shortage			
01-Jun-07	127.6	0.0	0.0	127.6	0.0	127.6	0.0	1.033	0.0
01-Jun-08	559.4	0.0	(40.0)	519.4	(58.4)	461.0	488.0	1.034	504.7
01-Jun-09	892.9	0.0	(474.7)	418.2	(14.3)	403.9	570.3	1.033	589.2
01-Jun-10	962.9	0.0	(516.3)	446.6	(7.7)	438.9	572.8	1.035	592.6
01-Jun-11	1,826.6	0.0	(1,052.4)	774.2	0.0	774.2	1,117.9	1.035	1,156.5
01-Jun-12	8,752.6	(11.7)	(2,253.6)	6,487.3	(34.9)	6,452.4	7,443.7	1.037	7,718.4
01-Jun-13	10,779.6	0.0	(3,314.4)	7,465.2	(30.5)	7,434.7	8,240.1	1.042	8,586.8
01-Jun-14	14,943.0	0.0	(6,731.8)	8,211.2	(219.4)	7,991.8	8,923.4	1.042	9,301.2
01-Jun-15	15,774.8	(321.1)	(4,829.7)	10,624.0	(61.8)	10,562.2	10,946.0	1.038	11,360.0
01-Jun-16	13,284.7	(19.4)	(4,800.7)	8,464.6	(455.4)	8,009.2	8,961.2	1.042	9,333.4
01-Jun-17	11,870.7	0.0	(3,870.8)	7,999.9	(30.3)	7,969.6	8,681.4	1.039	9,016.3
01-Jun-18	11,435.4	0.0	(3,182.4)	8,253.0	(1.0)	8,252.0	8,512.0	1.091	9,282.4
01-Jun-19	10,703.1	0.0	(2,138.8)	8,564.3	(0.4)	8,563.9	9,229.9	1.090	10,056.0
01-Jun-20	9,445.7	0.0	(2,399.5)	7,046.2	(0.1)	7,046.1	7,867.6	1.088	8,561.5
01-Jun-21	11,427.7	0.0	(4,111.0)	7,316.7	0.0	7,316.7	7,754.2	1.087	8,429.6
01-Jun-22	8,866.2	0.0	(570.0)	8,296.2	(52.1)	8,244.1	8,518.5	1.091	9,290.2
01-Jun-23	8,174.1	0.0	(466.2)	7,707.9	(161.5)	7,546.4	7,383.0	1.093	8,069.6
01-Jun-24	8,064.7	0.0	(364.8)	7,699.9	(507.4)	7,192.5	6,758.7	1.117	7,549.5
01-Jun-25	6,064.7	0.0	0.0	6,064.7	0.0	6,064.7	0.0	0.760	0.0

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.¹⁰⁰ 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.¹⁰¹ 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,

⁹⁷ 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.

⁹⁸ 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.

⁹⁹ 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.

¹⁰⁰ *Class Average Capacity Factors – Wind and Solar Resources*, PJM Interconnection L.L.C. (June 1, 2017).

¹⁰¹ See 176 FERC ¶ 61,056 (2021). There are multiple ways to apply the ELCC method. There is not a single ELCC method.

among other issues.¹⁰² 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. On January 30, 2024, FERC accepted PJM's modified marginal ELCC approach and it was used to determine capacity values for the 2025/2026 Base Residual Auction held in July 2024.¹⁰³ PJM's modified marginal ELCC approach was used to determine the capacity values for thermal resources and demand resources in addition to the intermittent resources.

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 but PJM's implementation does not. Neither intermittent nor thermal resources are the perfect resource. There are thermal resources, 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

¹⁰² 182 FERC ¶ 61,109 (2023).

¹⁰³ 186 FERC ¶ 61,080 (2024).

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.¹⁰⁴ 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.¹⁰⁵

PJM's latest approach to ELCC is a marginal 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

¹⁰⁴ "ELCC Class Ratings for 2024-2025 BRA," PJM Interconnection LLC. (December 28, 2021) <<https://www.pjm.com/planning/resource-adequacy-planning/effective-load-carrying-capability>>.

¹⁰⁵ 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>.

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 were 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.¹⁰⁶ The corresponding performance obligation of an intermittent resource is to produce at its corresponding maximum energy 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.¹⁰⁷

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).¹⁰⁸ 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 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

¹⁰⁶ 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>>.

¹⁰⁷ 183 FERC ¶61,009.

¹⁰⁸ OATT Part VII, Subpart E § 332.

mitigation, would have increased the market clearing price.¹⁰⁹ ¹¹⁰ ¹¹¹ 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, 2021.¹¹² The Commission rejected a more recent attempt to undermine the Market Seller Offer Cap rules by order issued February 6, 2024.¹¹³

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.

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.¹¹⁴ 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

¹⁰⁹ See OATT Attachment DD § 6.5.

¹¹⁰ 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).

¹¹¹ 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).

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

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

¹¹⁴ OATT Attachment DD § 6.8(b).

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.¹¹⁵ 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.¹¹⁶ 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.¹¹⁷

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).¹¹⁸ 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.

¹¹⁵ *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).

¹¹⁶ 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).

¹¹⁷ OATT Attachment DD § 6.8(a).

¹¹⁸ 151 FERC ¶ 61,208 (2015).

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. However the PJM method for calculating forward looking net revenues is significantly flawed and overestimates net revenues.

PJM had a forward looking net revenue calculation in the tariff that applied to RPM Auctions for the 2022/2023 Delivery Year.¹¹⁹ FERC subsequently reversed its approval of that method as part of rejecting PJM's ORDC filing.¹²⁰ 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.¹²¹

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

¹¹⁹ 171 FERC ¶ 61,153 (May 21, 2020) and 173 FERC ¶ 61,134 (November 12, 2020).

¹²⁰ 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.

¹²¹ See "PJM Manual 15: Cost Development Guidelines," § 12.7 IMM Opportunity Cost Calculator, Rev. 45 (Sep. 1, 2024).

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.¹²²

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.¹²³ The Commission rejected a more recent attempt by PJM to undermine the Market Seller Offer Cap rules by order issued February 6, 2024.¹²⁴

2024/2025 RPM Third Incremental Auction

As shown in Table 5-13, 320 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 320 generation resources, 223 generation resources elected the offer cap option of 1.1 times the BRA clearing price (69.7 percent), 62 generation resources had default ACR based offer caps (19.4 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 26 generation resources were price takers (8.1 percent). Market power mitigation was applied to seven Capacity Performance sell offers. Based on the FERC Order in Docket No. ER23-729-

¹²² OATT Attachment DD § 10A (d).

¹²³ 176 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).

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

002, PJM reran the 2024/2025 Third Incremental Auction with final results posted on May 23, 2024.¹²⁵

2025/2026 RPM Base Residual Auction

As shown in Table 5-13, 1,119 generation resources submitted Capacity Performance offers in the 2025/2026 RPM Base Residual Auction. Unit specific offer caps were calculated for 61 generation resources (5.5 percent). Of the 1,119 generation resources, 729 generation resources had default ACR based offer caps (65.1 percent), 46 generation resources had unit specific ACR based offer caps (4.1 percent), 15 generation resource had a unit specific opportunity cost-based offer cap (1.3 percent), 25 Planned Generation Capacity Resources had uncapped offers (2.2 percent), one generation resource had an uncapped planned uprate and default ACR based offer cap for the existing portion (0.1 percent), and the remaining 303 generation resources were price takers (27.1 percent). Market power mitigation was applied to sell offers of 16 generation resources.

Table 5-13 ACR statistics: RPM auctions held through the first nine months, 2024

Offer Cap/Mitigation Type	2024/2025 Third Incremental Auction		2025/2026 Base Residual Auction	
	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	62	19.4%	729	65.1%
Unit specific ACR (APIR)	3	0.9%	1	0.1%
Unit specific ACR (APIR and CPQR)	0	0.0%	11	1.0%
Unit specific ACR (non-APIR)	2	0.6%	5	0.4%
Unit specific ACR (non-APIR and CPQR)	0	0.0%	29	2.6%
Opportunity cost input	2	0.6%	15	1.3%
Default ACR and opportunity cost	0	0.0%	0	0.0%
Net CONE times B	NA	NA	NA	NA
Offer cap of 1.1 times BRA clearing price elected	223	69.7%	NA	NA
Uncapped planned uprate and default ACR	0	0.0%	1	0.1%
Uncapped planned uprate and opportunity cost	0	0.0%	0	0.0%
Uncapped planned uprate and Net CONE times B	NA	NA	NA	NA
Uncapped planned uprate and price taker	0	0.0%	0	0.0%
Uncapped planned uprate and 1.1 times BRA clearing price elected	0	0.0%	NA	NA
Uncapped planned generation resources	2	0.6%	25	2.2%
Existing generation resources as price takers	26	8.1%	303	27.1%
Total Generation Capacity Resources offered	320	100.0%	1,119	100.0%

¹²⁵ 187 FERC ¶ 61,065 (2024).

MOPR

By order issued December 19, 2019, the RPM Minimum Offer Price Rule (MOPR) was modified.¹²⁶ 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.¹²⁷ The MMU testified at the Technical Conference and provided comments and responses to the Commission's questions following the conference.¹²⁸

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.¹²⁹ 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.

¹²⁶ 169 FERC ¶ 61,239 (2019), *order denying reh'g*, 171 FERC ¶ 61,035 (2020), *aff'd* PJM Power Providers Group, et al. v. FERC, Case No. 21-3068 [3rd Cir. December 1, 2023], *cert denied*.

¹²⁷ Technical Conference regarding Resource Adequacy in the Evolving Electricity Sector, Docket No. AD21-10 (March 23, 2021).

¹²⁸ *Modernizing Electricity Market Design*, Comments of the Independent Market Monitor for PJM, Docket No. AD21-10 (April 26, 2021).

¹²⁹ *PJM Interconnection, LLC*, Notice of Filing Taking Effect by Operation of Law, Docket No. ER21-2582 (September 29, 2021).

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.¹³⁰

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.¹³¹ The change in the offset affected MOPR floor prices and the results of unit specific reviews under MOPR in the 2023/2024 BRA. This decision was reversed in the Commission's order related to the ORDC matter.¹³²

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 5-14, 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 or the 2025/2026 RPM Base Residual 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. Of the 212.6 MW offered in the 2025/2026 RPM Base Residual Auction that were subject to MOPR, 212.0 MW cleared and 0.6 MW did not clear.

¹³⁰ 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).

¹³¹ 173 FERC ¶ 61,134 (2020).

¹³² 177 FERC ¶ 61,209 (2021).

Table 5-14 MOPR statistics: RPM auctions held through the first nine months, 2024

	MOPR Type	Calculation Type	Number of Requests	ICAP (MW)			UCAP (MW)	
				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
2025/2026 Base Residual 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	634.7	212.6	212.0
	Total		0	0.0	0.0	634.7	212.6	212.0

Replacement Capacity¹³³

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 5-15 shows the committed and replacement capacity for all capacity resources for June 1 of each year from 2007 through 2024.

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.

¹³³ 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).

PJM's sale of capacity in IAs at very low prices, given that PJM announces the MW quantity and the sell offer price in advance of the auctions, further reduces IA prices and increases the incentive of DR sellers to speculate in the BRAs. The MMU recommends that if PJM sells capacity in incremental auctions, PJM should offer the capacity for sale at the BRA clearing price in order to avoid suppressing the IA price below

the competitive level. If the PJM sell offer price is not the BRA clearing price, PJM should not reveal its proposed sell offer price or the MW quantity to be sold prior to the auction.

It has been asserted that selling at a high price in the BRA and buying back at a low price in the IA is just a market transaction and therefore does not constitute a problem. But permitting DR to be an option in the BRA rather than requiring DR to be a commitment to provide a physical asset gives DR an unfair advantage and creates a self fulfilling dynamic that incents more of the same behavior. Only DR is permitted to be an option in the BRA. Generation resources must have met physical milestones in order to offer in the BRA. It is not reasonable to permit DR capacity resources to have a different product definition than generation capacity resources. Even if DR is treated as an annual product, this unique treatment as an option makes DR an inferior resource and not a complete substitute for generation resources. The current approach to DR is also inconsistent with the history of the definition of capacity in PJM, which has always been that capacity is physical and unit specific. The current approach to DR effectively makes DR a virtual participant in the PJM Capacity Market. That option should be eliminated.

The definition of demand side resources in PJM capacity markets is flawed in a variety of ways. The current demand side definition should be replaced with a definition that includes demand on the demand side of the market. There are ways to ensure and enhance the vibrancy of demand side without negatively affecting markets for generation.

**Table 5-15 RPM commitments and replacements for all Capacity Resources:
June 1, 2007 to June 1, 2025**

	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	154,362.5	0.0	(4,046.2)	150,316.3	(4,371.0)	145,945.3
01-Jun-25	135,684.0	0.0	0.0	135,684.0	0.0	135,684.0

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 5-16 shows RPM clearing prices for the 2021/2022 through 2025/2026 Delivery Years for all RPM auctions held through the first nine months of 2024, and Table 5-17 shows the RPM cleared MW for the 2021/2022 through 2025/2026 Delivery Years for all RPM auctions held through the first nine months of 2024.

Figure 5-6 shows the RPM cleared MW weighted-average prices for each LDA from the 2022/2023 Delivery Year to the current delivery year, and all results for auctions for future delivery years that have been held through the first

nine months of 2024. A summary of these weighted average prices is given in Table 5-18.

Table 5-19 shows RPM revenue by delivery year for all RPM auctions held through the first nine months of 2024 based on the unforced MW cleared and the resource clearing prices. For the 2024/2025 Delivery Year, RPM revenue is \$2.6 billion. For the 2025/2026 Delivery Year, RPM revenue is \$14.7 billion.

Table 5-20 shows RPM revenue by calendar year for all RPM auctions held through the first nine months of 2024. In 2024, RPM revenue is \$2.5 billion. In 2025, RPM revenue is \$9.7 billion.

Table 5-21 shows the RPM annual charges to load. For the 2023/2024 Delivery Year, annual charges to load were \$2.2 billion. For the 2024/2025 Delivery Year, annual charges to load are \$2.5 billion.

Table 5-16 Capacity market clearing prices: 2021/2022 through 2025/2026 RPM Auctions

		RPM Clearing Price (\$ per MW-day)														
Product Type		RTO	MAAC	APS	PPL	EMAAC	SWMAAC	DPL		PSEG						
								South	PSEG	North	PEPCO	ATSI	COMED	BGE	DUKE	DOM
2021/2022 BRA	Capacity Performance	\$140.00	\$140.00	\$140.00	\$140.00	\$165.73	\$140.00	\$165.73	\$204.29	\$204.29	\$140.00	\$171.33	\$195.55	\$200.30	\$140.00	\$140.00
2021/2022 First Incremental Auction	Capacity Performance	\$23.00	\$23.00	\$23.00	\$23.00	\$25.00	\$23.00	\$25.00	\$45.00	\$219.00	\$23.00	\$23.00	\$23.00	\$60.00	\$23.00	\$23.00
2021/2022 Second Incremental Auction	Capacity Performance	\$10.26	\$10.26	\$10.26	\$10.26	\$15.37	\$10.26	\$15.37	\$125.00	\$125.00	\$10.26	\$10.26	\$10.26	\$70.00	\$10.26	\$10.26
2021/2022 Third Incremental Auction	Capacity Performance	\$20.55	\$20.55	\$20.55	\$20.55	\$26.36	\$20.55	\$26.36	\$31.00	\$31.00	\$20.55	\$20.55	\$20.55	\$39.00	\$20.55	\$20.55
2022/2023 BRA	Capacity Performance	\$50.09	\$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	\$50.09
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	\$50.05
2023/2024 BRA	Capacity Performance	\$34.13	\$49.49	\$34.13	\$49.49	\$49.49	\$49.49	\$69.95	\$49.49	\$49.49	\$49.49	\$34.13	\$34.13	\$69.95	\$34.13	\$34.13
2023/2024 Third Incremental Auction	Capacity Performance	\$37.53	\$49.49	\$37.53	\$49.49	\$146.03	\$49.49	\$146.03	\$146.03	\$146.03	\$49.49	\$37.53	\$37.53	\$79.03	\$37.53	\$37.53
2024/2025 BRA	Capacity Performance	\$28.92	\$49.49	\$28.92	\$49.49	\$53.60	\$49.49	\$426.17	\$53.60	\$53.60	\$49.49	\$28.92	\$28.92	\$73.00	\$96.24	\$28.92
2024/2025 Third Incremental Auction	Capacity Performance	\$58.00	\$80.00	\$58.00	\$80.00	\$175.81	\$80.00	\$175.81	\$175.81	\$175.81	\$80.00	\$58.00	\$58.00	\$155.29	\$58.00	\$58.00
2025/2026 BRA	Capacity Performance	\$269.92	\$269.92	\$269.92	\$269.92	\$269.92	\$269.92	\$269.92	\$269.92	\$269.92	\$269.92	\$269.92	\$269.92	\$466.35	\$269.92	\$444.26

Table 5-17 Capacity market cleared MW: 2021/2022 through 2025/2026 RPM Auctions¹³⁴

		UCAP (MW)															
Delivery Year		RTO	MAAC	APS	PPL	EMAAC	DPL South	PSEG	PSEG		PEPCO	ATSI	COMED	BGE	DUKE	DOM	TOTAL
								North									
2021/2022	BASE	26,552.8	12,565.1	10,136.1	15,368.6	22,286.8	1,673.8	2,237.7	3,134.1	6,013.2	8,010.5	22,358.1	4,200.7	2,746.1	26,343.7	163,627.3	
2021/2022	FIRST	118.7	200.4	45.9	27.2	119.0	15.3	18.3	79.1	207.9	739.3	360.4	48.7	87.6	75.4	2,143.2	
2021/2022	SECOND	1,082.0	335.8	30.3	55.4	129.9	39.3	97.0	98.1	75.7	1,216.8	205.9	115.5	65.3	160.5	3,707.5	
2021/2022	THIRD	1,243.7	168.7	231.6	127.8	911.0	18.3	227.7	244.8	67.2	942.7	221.7	275.9	159.2	394.7	5,235.0	
2022/2023	BASE	29,596.0	12,804.7	10,147.4	14,118.7	23,651.2	1,312.9	1,914.3	2,531.1	3,621.8	10,550.7	19,223.7	4,750.9	2,117.7	8,136.3	144,477.3	
2022/2023	THIRD	703.3	338.9	84.2	105.7	572.2	9.4	244.3	402.0	27.4	358.0	2,292.3	409.7	44.8	395.7	5,987.9	
2023/2024	BASE	28,642.1	10,098.5	8,145.5	14,352.7	22,912.6	1,412.8	2,497.1	3,344.9	3,521.8	9,535.9	25,368.9	5,001.0	1,966.4	8,266.7	145,066.9	
2023/2024	THIRD	255.9	1,786.4	395.0	79.3	671.0	24.2	32.4	43.8	15.3	355.8	1,050.0	240.0	68.4	59.8	5,077.0	
2024/2025	BASE	28,760.7	10,854.4	8,874.0	14,178.1	23,135.1	1,448.6	2,665.3	3,494.3	3,429.7	9,720.6	25,156.1	5,056.5	2,062.1	8,646.1	147,481.5	
2024/2025	THIRD	365.3	744.8	815.6	665.2	963.0	33.2	48.7	60.2	78.7	245.6	2,370.0	222.5	90.2	177.9	6,881.0	
2025/2026	BRA	24,573.1	9,490.1	8,481.3	12,368.8	19,043.0	958.7	1,894.3	2,520.1	2,274.4	7,778.5	21,814.2	2,800.6	1,636.7	20,050.2	135,684.0	

¹³⁴ The MW values in this table refer to rest of LDA or RTO values, which are net of nested LDA values.

Table 5-18 Weighted-average clearing prices by zone: 2022/2023 through 2025/2026

	Weighted Average Clearing Price (\$ per MW-day)			
	2022/2023	2023/2024	2024/2025	2025/2026
LDA				
RTO				
AEP	\$49.35	\$34.21	\$29.80	\$269.92
APS	\$49.35	\$34.21	\$29.80	\$269.92
ATSI	\$48.89	\$34.26	\$29.80	\$269.92
Cleveland	\$49.41	\$34.21	\$28.92	\$269.92
COMED	\$63.70	\$34.27	\$31.42	\$269.92
DAY	\$49.16	\$34.17	\$29.13	\$269.92
DUKE	\$70.57	\$34.24	\$94.57	\$269.92
DUQ	\$49.35	\$34.21	\$29.80	\$269.92
DOM	\$49.35	\$34.21	\$29.80	\$444.25
EKPC	\$49.35	\$34.21	\$29.80	\$269.92
MAAC				
EMAAC				
ACEC	\$96.31	\$52.21	\$58.47	\$269.92
DPL	\$96.31	\$52.21	\$58.47	\$269.92
DPL South	\$97.41	\$71.26	\$420.55	\$269.92
JCPLC	\$96.31	\$52.21	\$58.47	\$269.92
PECO	\$96.31	\$52.21	\$58.47	\$269.92
PSEG	\$90.67	\$50.71	\$55.54	\$269.92
PSEG North	\$89.21	\$50.73	\$55.48	\$269.92
REC	\$96.31	\$52.21	\$58.47	\$269.92
SWMAAC				
BGE	\$119.73	\$70.65	\$77.88	\$465.38
PEPCO	\$94.75	\$49.46	\$50.12	\$269.92
WMAAC				
MEC	\$94.49	\$49.49	\$51.07	\$269.92
PE	\$94.49	\$49.49	\$51.07	\$269.92
PPL	\$95.29	\$49.49	\$51.18	\$269.92

Table 5-19 RPM revenue by delivery year: 2007/2008 through 2025/2026¹³⁵

Delivery Year	Weighted Average RPM Price (\$ per MW-day)	Weighted Average Cleared UCAP (MW)	Days	RPM Revenue
2007/2008	\$89.78	129,409.2	366	\$4,252,287,381
2008/2009	\$127.67	130,629.8	365	\$6,087,147,586
2009/2010	\$153.37	134,030.2	365	\$7,503,218,157
2010/2011	\$172.71	134,036.2	365	\$8,449,652,496
2011/2012	\$108.63	134,182.6	366	\$5,335,087,023
2012/2013	\$75.08	141,283.9	365	\$3,871,714,635
2013/2014	\$116.55	159,844.5	365	\$6,799,778,047
2014/2015	\$126.40	161,205.0	365	\$7,437,267,646
2015/2016	\$160.01	173,519.4	366	\$10,161,726,902
2016/2017	\$121.84	179,749.0	365	\$7,993,888,695
2017/2018	\$141.19	180,590.5	365	\$9,306,676,719
2018/2019	\$172.09	175,996.0	365	\$11,054,943,851
2019/2020	\$109.82	177,064.2	366	\$7,116,815,360
2020/2021	\$111.07	173,688.5	365	\$7,041,524,517
2021/2022	\$147.33	174,713.0	365	\$9,395,567,946
2022/2023	\$72.33	150,465.2	365	\$3,972,428,671
2023/2024	\$42.01	150,143.9	366	\$2,308,670,914
2024/2025	\$45.57	154,362.5	365	\$2,567,491,013
2025/2026	\$296.56	135,684.0	365	\$14,687,047,370

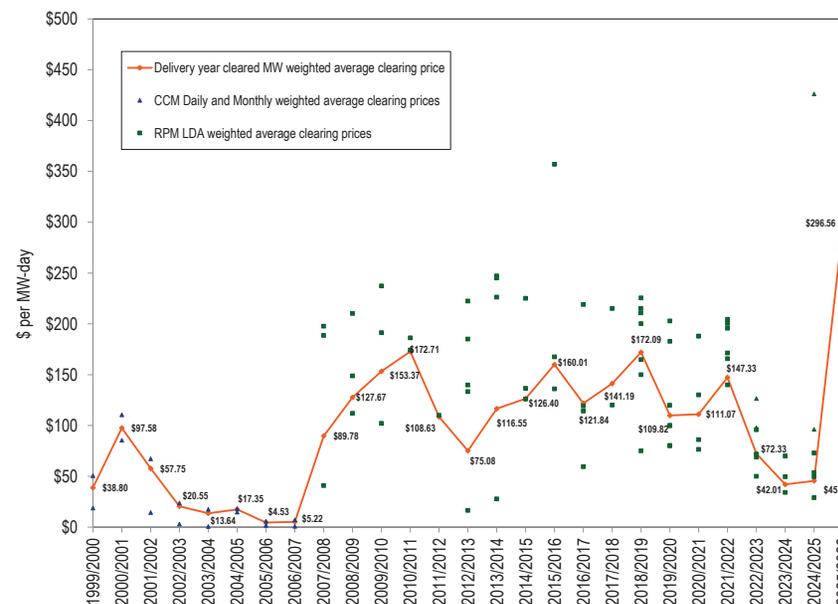
¹³⁵ The results for the ATSI Integration Auctions are not included in this table.

Table 5-20 RPM revenue by calendar year: 2007 through 2026¹³⁶

Year	Weighted Average RPM Price (\$ per MW-day)	Weighted Average Cleared UCAP (MW)	Effective Days	RPM Revenue
2007	\$89.78	75,665.5	214	\$2,486,310,108
2008	\$111.93	130,332.1	366	\$5,334,880,241
2009	\$142.74	132,623.5	365	\$6,917,391,702
2010	\$164.71	134,033.7	365	\$8,058,113,907
2011	\$135.14	133,907.1	365	\$6,615,032,130
2012	\$89.01	138,561.1	366	\$4,485,656,150
2013	\$99.39	152,166.0	365	\$5,588,442,225
2014	\$122.32	160,642.2	365	\$7,173,539,072
2015	\$146.10	168,147.0	365	\$9,018,343,604
2016	\$137.69	177,449.8	366	\$8,906,998,628
2017	\$133.19	180,242.4	365	\$8,763,578,112
2018	\$159.31	177,896.7	365	\$10,331,688,133
2019	\$135.58	176,338.6	365	\$8,734,613,179
2020	\$110.55	175,368.7	366	\$7,084,072,778
2021	\$132.33	174,289.2	365	\$8,421,703,404
2022	\$103.36	160,496.5	365	\$6,215,973,960
2023	\$54.56	150,036.3	365	\$2,993,266,921
2024	\$44.09	152,857.8	366	\$2,464,115,790
2025	\$192.73	143,411.3	365	\$9,673,203,507
2026	\$296.56	56,132.3	151	\$6,076,011,378

¹³⁶ The results for the ATSI Integration Auctions are not included in this table.

Figure 5-5 History of capacity prices: 1999/2000 through 2025/2026¹³⁷



¹³⁷ 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: 2022/2023 through 2025/2026

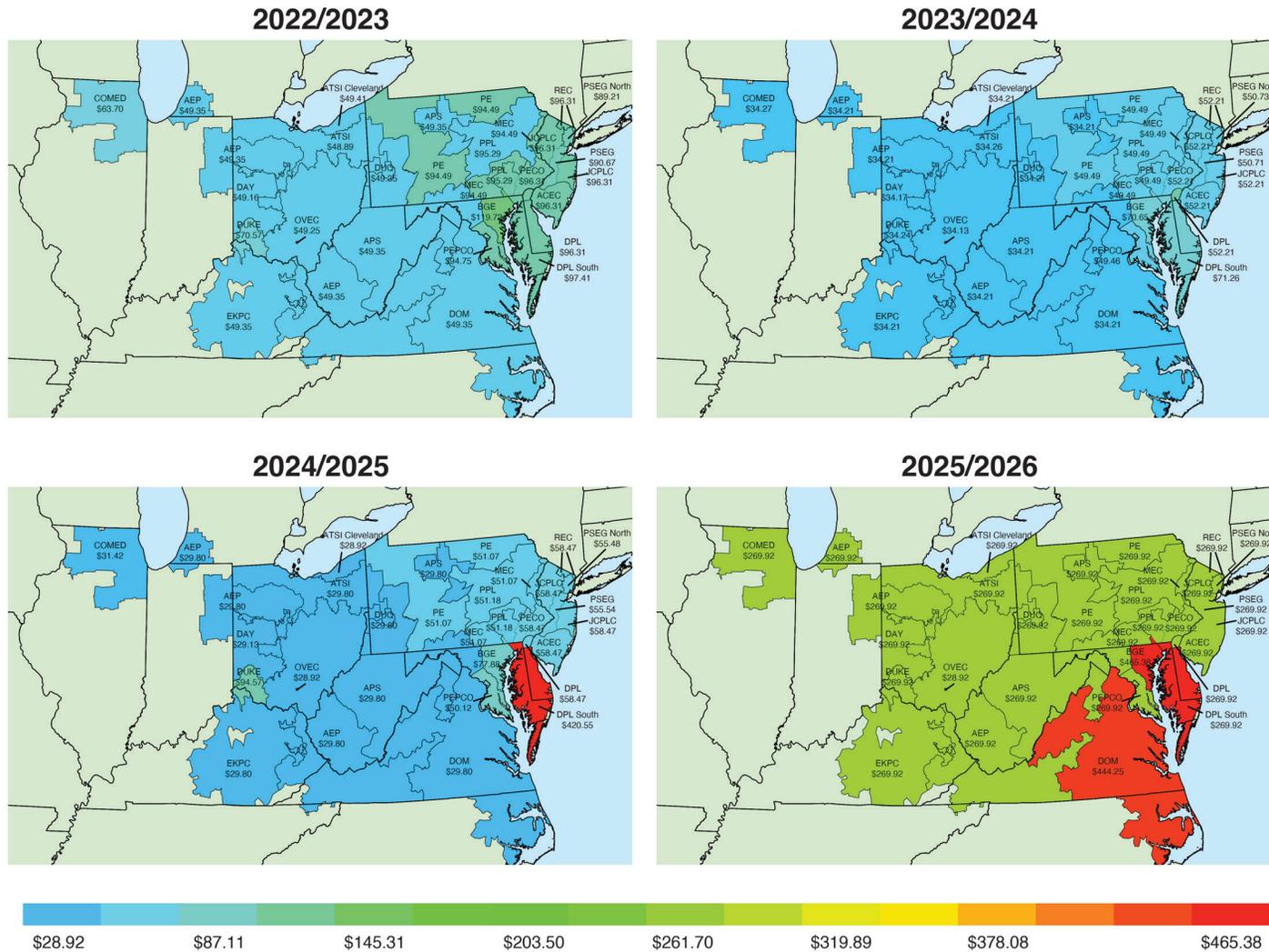


Table 5-21 RPM cost to load: 2022/2023 through 2025/2026 RPM Auctions^{138 139 140}

	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	\$29.50	77,398.7	\$833,520,097
EMAAC	\$56.56	32,270.3	\$666,184,144
WMAAC	\$50.22	22,872.2	\$419,263,035
Rest of EMAAC	\$175.22	4,590.0	\$293,561,344
BGE	\$61.53	7,726.0	\$173,527,700
DEOK	\$57.93	5,254.4	\$111,105,639
Total		150,111.7	\$2,497,161,960
2025/2026			
Rest of RTO	\$270.35	107,762.5	\$10,633,606,312
BGE	\$306.98	5,968.6	\$668,769,284
DOM	\$429.57	21,952.9	\$3,442,062,633
Total		135,684.0	\$14,744,438,229

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

139 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.

140 The net load prices and obligation MW for 2025/2026 are not final.

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.^{141 142 143 144 145 146} 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.

141 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).

142 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).

143 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).

144 *In the Matter of the Investigation of Resource Adequacy Alternatives*, New Jersey Board of Public Utilities, Docket No. E020030203. Monitoring Analytics, LLC Comments, <http://www.monitoringanalytics.com/filings/2020/IMM_Comments_Docket_No_E020030203_20200520.pdf> (May 20, 2020). Monitoring Analytics, LLC, Reply Comments <http://www.monitoringanalytics.com/filings/2020/IMM_Reply_Comments_Docket_No_E020030203_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_E020030203_20200715.pdf> (July 15, 2020).

145 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).

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

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

With the elimination of the 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.

Dominion Energy Virginia elected the FRR option for the 2022/2023 through 2024/2025 delivery years but returned to the capacity market for the 2025/2026 BRA.

CRF Issue¹⁴⁷

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 205.¹⁴⁸ 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:^{149 150}

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

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.¹⁵¹ FERC rejected the MMU's unit specific state tax recommendation. Going forward, PJM will post the CRFs on their website. Table 5-23 shows the CRFs that are currently posted. The values in Table 5-23 were calculated using the formula above and the financial assumptions in Table 5-24. Bonus depreciation assumptions vary by delivery year with

¹⁴⁷ See related filing on CRF issue in black start: Comments of the Independent Market Monitor for PJM, Docket No. ER21-1635 (April 28, 2021).

¹⁴⁸ "Revisions to Capital Recovery Factor for Avoidable Project Investment Cost Determinations and Request for Waiver of Sixty-Day Notice Requirement," PJM Interconnection LLC, Docket No. ER21-1844-000 (May 4, 2021).

¹⁴⁹ See "Comments of the Independent Market Monitor for PJM," Docket No. ER21-1844-000 (May 25, 2021).

¹⁵⁰ 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.

¹⁵¹ Order 176 FERC ¶61,003 (July 2, 2021).

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 5-22 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 example, Table 5-23, 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.¹⁵² 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 5-23 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.¹⁵³

¹⁵² 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>>.

¹⁵³ Order 176 FERC ¶61,003 (July 2, 2021) at 28.

Table 5-23 Levelized CRF values: Delivery Year 2023/2024 through Delivery Year 2026/2027

Age of Unit (Years)	Cost Recovery Period	2023/2024	2024/2025	2025/2026	2026/2027
		Bonus Depreciation Percent			
		80%	60%	40%	20%
1 to 5	30	0.091	0.094	0.096	0.105
6 to 10	25	0.096	0.098	0.101	0.110
11 to 15	20	0.104	0.107	0.110	0.118
16 to 20	15	0.119	0.122	0.126	0.134
21 to 25	10	0.152	0.158	0.164	0.174
25 Plus	5	0.258	0.271	0.283	0.301
Mandatory CapEx	4	0.312	0.328	0.345	0.367
40 Plus Alternative	1	1.100	1.100	1.100	1.100

Table 5-24 Financial parameter and tax rate assumptions for CRF calculations

Parameter	Parameter Values	
	Prior to 2026/2027	2026/2027
Equity Funding Percent	45.000%	45.000%
Debt Funding Percent	55.000%	55.000%
Equity Rate	13.000%	14.100%
Debt Interest Rate	6.000%	6.300%
Federal Income Tax Rate	21.000%	21.000%
State Income Tax Rate	9.300%	9.933%
Effective Income Tax Rate	28.347%	28.847%
After Tax Weighted Average Cost of Capital	8.215%	8.810%

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 5-25 compares CRFs calculated under the two approaches using the assumptions in Table 5-24. 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.

Table 5-25 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 5-26). 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 5-26 Earliest deactivation dates allowed based on quarterly submission

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

Generation owners seeking a capacity market must offer exemption for a delivery year must submit their deactivation request no later than the December 1 preceding the Base Residual Auction or 120 days before the start of an Incremental Auction for that delivery year.¹⁵⁴ 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.¹⁵⁵

Table 5-27 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 185 deactivation requests submitted, 31 units (16.8 percent) deactivated an average of 157 days earlier than their initially requested date; 30 units (16.2 percent) deactivated an average of 103 days later than the originally requested deactivation date; and 77 units (41.6 percent) deactivated on their initially requested date. Twenty (10.8 percent) of the unit deactivations were cancelled an average of 250 days before their scheduled deactivation date, and 27 (14.6 percent) of the unit deactivations have not yet reached their target retirement date. Table 5-28 shows this information broken out by fuel types.

Table 5-27 Timing of actual unit deactivations compared to requested deactivation date: Requests submitted January 2018 through September 2024

Status	Number of Units	Percent	Average Days Deviation from Originally Requested Date
Early	31	15.7%	(157)
Late	30	15.2%	103
On time	79	40.1%	0
Cancelled	24	12.2%	(256)
Pending	33	16.8%	-
Total	197	100.0%	-

¹⁵⁴ OAIT Attachment DD § 6.6(g).
¹⁵⁵ OAIT Part V §113.

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

Fuel Type	Status	Number of Units	Percent	Average Days Deviation from Originally Requested Date
Biomass	Early	2	66.7%	(4)
	Late	1	33.3%	-
	On time	0	0.0%	-
	Cancelled	0	0.0%	-
	Pending	0	0.0%	-
Total		3	100.0%	-
Coal	Early	15	31.3%	(169)
	Late	9	18.8%	78
	On time	16	33.3%	0
	Cancelled	4	8.3%	(371)
	Pending	4	8.3%	-
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	9.3%	(197)
	Late	6	14.0%	94
	On time	16	37.2%	0
	Cancelled	5	11.6%	-
	Pending	12	27.9%	-
Total		43	100.0%	-
Nuclear	Early	0	0.0%	-
	Late	0	0.0%	-
	On time	0	0.0%	-
	Cancelled	10	100.0%	(312)
	Pending	0	0.0%	-
Total		10	100.0%	-
Oil	Early	3	5.8%	(218)
	Late	7	13.5%	188
	On time	24	46.2%	0
	Cancelled	3	5.8%	(36)
	Pending	15	28.8%	-
Total		52	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	33.3%	-
	Late	0	0.0%	-
	On time	6	66.7%	0
	Cancelled	0	0.0%	-
	Pending	0	0.0%	-
Total		9	100.0%	-

Part V Reliability Service (RMR)

PJM must make out of market payments to units that want to retire (deactivate) but that PJM requires to remain in service, for limited operation, for a defined period because the unit is needed for reliability.¹⁵⁶ 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.

The MMU recommends that PJM treat the inclusion of RMR resources in the capacity market consistently. PJM currently includes RMR units in the reliability analysis for RPM auctions but does not include the RMR units in the supply curves. This approach is internally inconsistent. It would be internally consistent to leave the RMR units out of the CETO/CETL analysis. It would also be internally consistent to include the RMR units in the supply of capacity and in the CETO/CETL analysis. Including RMR resources in the capacity supply curve does not mean forcing unit owners to offer or to take on PAI risk, for example. It simply means that PJM would recognize the fact that PJM treats RMR resources as a source of reliability. The goal is to ensure that the underlying supply and demand fundamentals are included in the capacity market prices. These two options have very different implications for capacity market prices. There are times when a price signal for the entry of generation is appropriate, e.g. when the goal is to allow generation to compete

¹⁵⁶ OATT Part V §114.

to replace the transmission option, in whole or in part. There are times when a price signal for the entry of generation is not needed or appropriate, e.g. when PJM has committed to the construction of new transmission that will eliminate the price signal when complete. The relevant rules can and should be changed.

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.¹⁵⁷ 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.¹⁵⁸ PJM performs a system study to determine whether the system can accommodate the deactivation on the desired date, and if not, when it could.¹⁵⁹ 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.¹⁶⁰ The PJM market rules do not require an owner to remain in service, but owners must provide advance notice

¹⁵⁷ 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.")

¹⁵⁸ OATT § 113.2; OATT Attachment M § IV.1.

¹⁵⁹ OATT § 113.2.

¹⁶⁰ *Id.*

of a proposed deactivation (See Table 5-26).¹⁶¹ 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.¹⁶² 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.¹⁶³

Under the current rules, a unit remaining in service at PJM’s request can recover its costs of continuing to operate under either the deactivation avoidable cost rate (DACR), which is a formula rate, or the cost of service recovery rate. The deactivation avoidable cost rate is designed to permit the recovery of the costs of the unit’s “continued operation,” termed “avoidable costs,” plus an incentive adder.¹⁶⁴ Avoidable costs are defined to mean “incremental expenses directly required for the operation of a generating unit.”¹⁶⁵ The incentives escalate for each year of service (first year, 10 percent; second year, 20 percent; third year, 35 percent; fourth year, 50 percent).¹⁶⁶ 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.¹⁶⁷ Project investment is capped at \$2 million, above which FERC approval is required.¹⁶⁸ 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.¹⁶⁹

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.

¹⁶¹ OATT § 113.1.

¹⁶² OATT Attachment DD § 6.6(g).

¹⁶³ *Id.*

¹⁶⁴ 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).

¹⁶⁵ OATT § 115.

¹⁶⁶ *Id.*

¹⁶⁷ OATT § 118.

¹⁶⁸ OATT §§ 115, 117.

¹⁶⁹ OATT § 119.

Table 5-29 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 3.4 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.¹⁷⁰

¹⁷⁰ 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 5-29 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

Table 5-30 Part V reliability service cost summary¹⁷¹

Unit Names	Owner	Initial Filing		Actual		Weighted Average RPM Clearing Price (\$ per MW-day)
		Total Cost	Cost per MW-day	Total Cost	Cost per MW-day	
Brandon Shores 1	Talen Energy Corporation	\$327,039,342	\$393.45	NA	NA	\$296.56
Brandon Shores 2	Talen Energy Corporation	\$328,584,409	\$393.45	NA	NA	\$296.56
Wagner 3	Talen Energy Corporation	\$64,791,528	\$162.29	NA	NA	\$296.56
Wagner 4	Talen Energy Corporation	\$84,335,202	\$162.29	NA	NA	\$296.56
Indian River 4	NRG Power Marketing LLC	\$357,065,662	\$520.25	\$181,208,389	\$537.03	\$114.07
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

¹⁷¹ Actual cost data includes RMR charges through August 31, 2024.

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.¹⁷² In some cases, the filing included costs that already had been written off, or impaired, on the company's public books.¹⁷³ ¹⁷⁴ The requested cost of service recovery rates substantially exceed the actual costs of operating to provide the reliability required by PJM.

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

¹⁷² See, e.g., FERC Dockets Nos. ER10-1418-000, ER12-1901-000 and ER17-1083-000.

¹⁷³ See GenOn Filing, Docket No. ER12-1901-000 (May 31, 2012) at Exh. No. GPM-1 at 9:16-21.

¹⁷⁴ See NRG Filing, Docket No. ER22-1539-000 (April 1, 2022).

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 5-31 shows the capacity factors by unit type for the first nine months of 2023 and 2024. In the first nine months of 2024, nuclear units had a capacity factor of 95.0 percent, compared to 95.6 percent in the first nine months of 2023; combined cycle units had a capacity factor of 68.2 percent in the first nine months of 2024, compared to a capacity factor of 65.6 percent in the first nine months of

2023; coal units had a capacity factor of 38.2 percent in the first nine months of 2024, compared to 31.8 percent in the first nine months of 2023.

Table 5-31 Capacity factor (By unit type (GWh)): January through September, 2023 and 2024^{175 176 177}

Unit Type	2023 (Jan-Sep)		2024 (Jan-Sep)		Change in 2024 from 2023
	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor	
Battery	17.5	0.9%	38.0	1.7%	0.8%
Combined Cycle	250,809.2	65.6%	258,919.8	68.2%	2.6%
Single Fuel	217,378.3	71.0%	222,665.3	73.2%	2.2%
Dual Fuel	33,430.9	43.9%	36,254.4	47.9%	4.0%
Combustion Turbine	16,201.3	8.3%	17,984.5	9.5%	1.2%
Single Fuel	11,436.7	8.8%	11,095.9	8.5%	(0.3%)
Dual Fuel	4,764.7	7.3%	6,888.6	11.8%	4.6%
Diesel	315.1	12.4%	242.5	12.4%	0.0%
Single Fuel	303.7	13.4%	222.8	12.9%	(0.5%)
Dual Fuel	11.4	4.2%	19.7	8.7%	4.5%
Diesel (Landfill gas)	777.2	51.8%	686.1	50.1%	(1.7%)
Fuel Cell	145.5	81.1%	161.0	89.5%	8.3%
Nuclear	204,483.4	95.6%	203,815.3	95.0%	(0.7%)
Pumped Storage Hydro	6,123.5	17.2%	6,631.9	18.6%	1.4%
Run of River Hydro	6,014.4	44.7%	6,460.3	47.8%	3.1%
Solar	8,746.1	22.3%	13,629.2	21.0%	(1.2%)
Steam	101,378.7	28.1%	107,353.8	34.9%	6.8%
Biomass	3,961.3	66.6%	3,782.9	65.0%	(1.6%)
Coal	89,497.8	31.8%	93,487.4	38.2%	6.3%
Single Fuel	89,450.5	34.3%	93,487.4	38.2%	3.9%
Dual Fuel	47.3	0.2%	0.0	0.0%	(0.2%)
Natural Gas	7,121.1	44.2%	9,206.5	47.7%	3.4%
Single Fuel	375.3	54.6%	418.0	55.8%	1.2%
Dual Fuel	6,745.8	22.4%	8,788.5	28.7%	6.3%
Oil	798.6	3.0%	877.0	4.2%	1.2%
Wind	20,056.5	26.5%	21,814.3	27.4%	0.9%
Total	615,068.5	46.5%	637,736.7	49.4%	2.9%

¹⁷⁵ The capacity factors in this table are based on nameplate capacity values, and are calculated based on when the units come on line.

¹⁷⁶ 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.

¹⁷⁷ Hours in which batteries have net negative generation do not count toward their runtime.

Generator Performance Factors

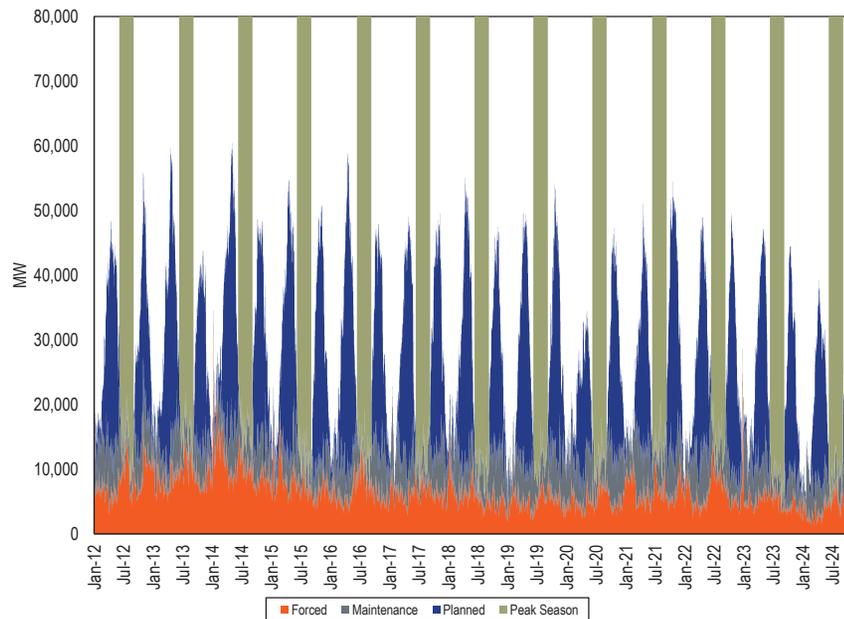
Generator outages fall into three categories: planned, maintenance, and forced. The scheduling of planned and maintenance outages must be approved by PJM. The approval may be withdrawn in order to maintain system reliability.¹⁷⁸ The PJM Market Rules do not specify any consequences if the planned outage 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.¹⁷⁹ Outages that are approved by PJM may be extended. An extension to a planned outage that enters the peak period is treated as a forced outage. A maintenance outage that is extended to more than nine days during the peak period is treated as a forced outage.

The MW on outage vary during the year. For example, the MW on planned outage are generally highest in the spring and fall, as shown in Figure 5-7, 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.

¹⁷⁸ "PJM Manual 10: Pre-Scheduling Operations," § 2.3.2 Maintenance Outage Rules, Rev. 40 (Dec. 15, 2021).

¹⁷⁹ OAT, Attachment K (Appendix) § 1.9.3 (b).

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



In the first nine months of 2024, forced outages were 19.2 percent lower, planned outages were 12.0 percent lower, and maintenance outages were 13.1 percent lower than in the first nine 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 5-32.

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

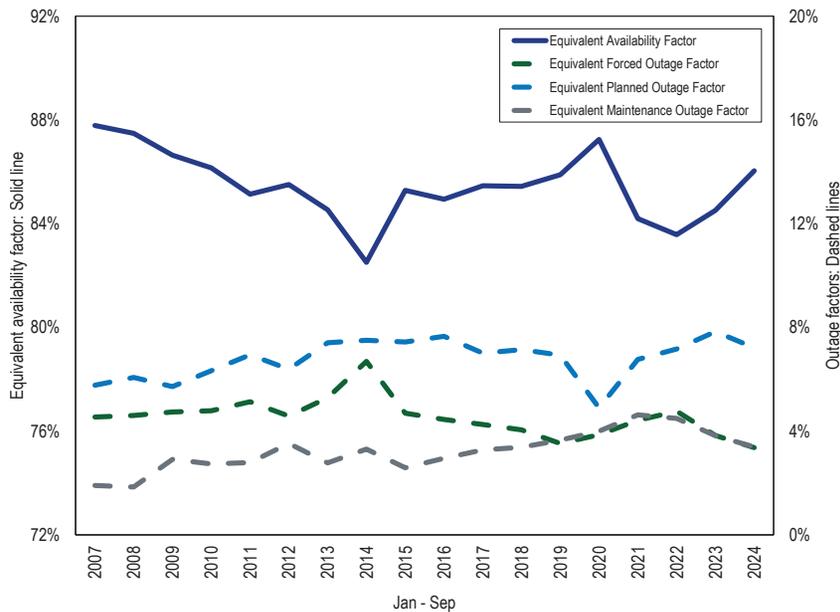


Table 5-32 EFOF, EPOF, EMOF and EAF by unit type: January through September, 2007 to 2024

Jan-Sep	Coal				Combined Cycle				Combustion Turbine				Diesel			
	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF
2007	7%	8%	3%	83%	2%	5%	1%	91%	5%	2%	2%	91%	11%	1%	2%	87%
2008	8%	7%	2%	83%	2%	5%	1%	91%	3%	4%	2%	91%	10%	1%	1%	88%
2009	7%	7%	4%	83%	4%	5%	4%	87%	1%	3%	2%	94%	7%	0%	1%	92%
2010	8%	8%	4%	79%	3%	6%	2%	89%	2%	2%	2%	94%	5%	1%	1%	94%
2011	9%	8%	4%	79%	3%	6%	2%	89%	2%	3%	2%	93%	4%	0%	2%	94%
2012	8%	8%	6%	78%	3%	6%	2%	89%	2%	2%	2%	94%	4%	0%	2%	94%
2013	9%	10%	5%	77%	2%	9%	3%	87%	5%	3%	1%	90%	6%	0%	1%	93%
2014	11%	9%	5%	75%	3%	9%	2%	86%	8%	3%	1%	87%	14%	1%	2%	83%
2015	8%	8%	4%	80%	2%	8%	2%	88%	3%	4%	2%	91%	9%	0%	2%	89%
2016	8%	8%	5%	78%	3%	8%	2%	87%	2%	4%	2%	91%	6%	0%	3%	92%
2017	10%	9%	6%	75%	2%	8%	2%	88%	1%	4%	2%	93%	6%	0%	2%	92%
2018	9%	10%	6%	75%	1%	8%	1%	89%	2%	4%	1%	92%	6%	1%	3%	90%
2019	8%	8%	7%	77%	1%	8%	2%	89%	2%	5%	2%	91%	7%	1%	2%	89%
2020	6%	6%	9%	79%	4%	5%	2%	89%	2%	3%	2%	93%	6%	0%	3%	91%
2021	8%	10%	10%	72%	3%	8%	2%	87%	2%	5%	3%	90%	8%	0%	3%	88%
2022	10%	10%	10%	70%	3%	9%	2%	86%	3%	5%	2%	90%	10%	0%	4%	85%
2023	8%	12%	7%	73%	3%	10%	2%	85%	2%	5%	2%	90%	13%	0%	3%	84%
2024	6%	9%	8%	77%	3%	9%	1%	87%	3%	4%	2%	91%	10%	1%	2%	88%

Jan-Sep	Hydroelectric				Nuclear				Other				Total			
	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF
2007	1%	6%	2%	92%	1%	4%	0%	95%	6%	7%	3%	84%	5%	6%	2%	88%
2008	2%	7%	2%	90%	1%	5%	1%	93%	4%	9%	3%	84%	5%	6%	2%	87%
2009	2%	9%	2%	86%	4%	4%	1%	91%	3%	8%	5%	84%	5%	6%	3%	87%
2010	1%	8%	2%	89%	2%	5%	1%	93%	5%	8%	4%	83%	5%	6%	3%	86%
2011	1%	14%	2%	83%	2%	5%	2%	91%	5%	8%	3%	84%	5%	7%	3%	85%
2012	4%	4%	2%	90%	1%	6%	1%	92%	5%	8%	4%	82%	5%	6%	4%	86%
2013	2%	7%	2%	89%	1%	5%	1%	93%	7%	9%	4%	80%	5%	7%	3%	85%
2014	2%	9%	3%	86%	2%	5%	1%	92%	7%	13%	6%	75%	7%	7%	3%	83%
2015	2%	8%	2%	88%	1%	4%	1%	93%	7%	16%	4%	74%	5%	7%	3%	85%
2016	2%	7%	3%	88%	2%	5%	1%	93%	5%	16%	4%	75%	4%	8%	3%	85%
2017	2%	6%	3%	89%	1%	5%	1%	94%	4%	9%	5%	82%	4%	7%	3%	85%
2018	2%	5%	3%	90%	1%	5%	1%	94%	4%	8%	8%	80%	4%	7%	3%	85%
2019	1%	5%	4%	90%	1%	5%	1%	94%	4%	10%	7%	79%	4%	7%	4%	86%
2020	4%	3%	3%	90%	2%	4%	1%	94%	8%	7%	5%	81%	4%	5%	4%	87%
2021	7%	3%	2%	87%	1%	4%	1%	94%	8%	6%	6%	80%	4%	7%	5%	84%
2022	3%	6%	3%	89%	1%	4%	1%	93%	6%	7%	6%	81%	5%	7%	4%	84%
2023	3%	11%	4%	81%	1%	4%	2%	94%	5%	7%	7%	81%	4%	8%	4%	85%
2024	3%	13%	3%	80%	1%	5%	2%	93%	5%	8%	3%	83%	3%	7%	3%	86%

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.¹⁸⁰ The EFORd metric includes all forced outages, regardless of the reason for those outages.

The average PJM EFORd in the first nine months of 2024 was 5.0 percent, a decrease from 5.6 percent in the first nine months of 2023. Figure 5-9 shows the average EFORd since 1999 for all units in PJM.¹⁸¹

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

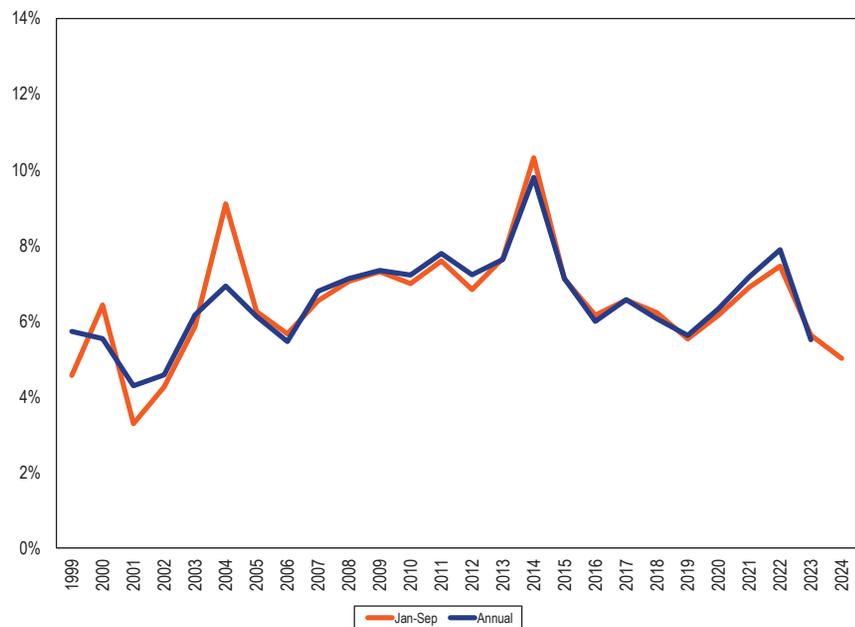


Table 5-33 shows the class average EFORd by unit type.

¹⁸⁰ 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.

¹⁸¹ The universe of units in PJM changed as the PJM footprint expanded and as units retired from and entered PJM markets. See the 2023 State of the Market Report for PJM, Appendix A: "PJM Overview" for details.

Table 5-33 EFORD by unit type: January through September, 2007 to 2024

	Jan-Sep																	
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Coal	7.7%	9.1%	8.6%	9.7%	11.1%	10.4%	11.1%	13.6%	9.9%	10.0%	12.1%	11.6%	10.8%	8.6%	11.2%	13.3%	11.5%	8.1%
Combined Cycle	4.2%	3.8%	5.7%	3.8%	3.5%	3.3%	2.4%	4.6%	2.7%	3.5%	2.7%	2.3%	2.0%	4.5%	3.6%	4.3%	4.0%	3.9%
Combustion Turbine	11.3%	11.6%	9.3%	9.3%	8.0%	6.5%	10.6%	18.0%	9.8%	5.3%	4.9%	6.4%	5.0%	4.2%	5.2%	5.7%	5.4%	6.5%
Diesel	12.6%	11.0%	9.0%	6.8%	9.8%	4.8%	6.1%	15.3%	9.8%	7.1%	7.1%	6.8%	8.0%	7.8%	10.7%	13.2%	15.2%	12.2%
Hydroelectric	1.8%	2.6%	2.8%	1.3%	2.0%	5.2%	3.4%	3.2%	3.2%	3.0%	2.9%	2.7%	1.6%	5.2%	9.0%	3.8%	4.5%	4.1%
Nuclear	1.3%	1.0%	4.4%	2.2%	2.6%	1.6%	1.1%	1.9%	1.2%	2.2%	0.6%	0.8%	0.7%	1.6%	0.9%	1.4%	0.5%	1.0%
Other	10.2%	9.6%	8.5%	7.9%	9.3%	8.3%	11.5%	12.9%	13.1%	9.8%	12.9%	9.6%	9.6%	17.0%	18.2%	16.5%	6.1%	7.6%
Total	6.5%	7.1%	7.3%	7.0%	7.6%	6.8%	7.7%	10.3%	7.1%	6.2%	6.6%	6.2%	5.5%	6.2%	6.9%	7.5%	5.6%	5.0%

EFORD vs EAF

EFORD is not an adequate measure of unit availability because EFORD measures only forced outages and does not account for planned or maintenance outages. Forced outage rates can be managed under the existing outage rules. 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.¹⁸² 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 5-34 shows the differences between EFORD and EAF by unit type.

Table 5-34 EFORD and EAF by unit type: January through September, 2012 to 2024

Jan-Sep	Unit Types															
	Coal		Combined Cycle		Combustion Turbine		Diesel		Hydroelectric		Nuclear		Other		All	
	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	10.4%	21.9%	3.3%	10.9%	6.5%	5.7%	4.8%	5.7%	5.2%	9.6%	1.6%	8.3%	8.3%	17.7%	6.8%	14.5%
2013	11.1%	22.7%	2.4%	13.0%	10.6%	9.8%	6.1%	7.3%	3.4%	10.7%	1.1%	6.9%	11.5%	20.0%	7.7%	15.5%
2014	13.6%	24.8%	4.6%	13.8%	18.0%	12.6%	15.3%	16.9%	3.2%	14.5%	1.9%	7.8%	12.9%	25.2%	10.3%	17.5%
2015	9.9%	20.2%	2.7%	12.1%	9.8%	8.7%	9.8%	11.3%	3.2%	12.2%	1.2%	7.0%	13.1%	26.4%	7.1%	14.7%
2016	10.0%	21.9%	3.5%	13.1%	5.3%	8.5%	7.1%	8.3%	3.0%	11.8%	2.2%	7.5%	9.8%	25.3%	6.2%	15.1%
2017	12.1%	25.2%	2.7%	12.0%	4.9%	6.8%	7.1%	7.9%	2.9%	10.6%	0.6%	5.9%	12.9%	18.1%	6.6%	14.5%
2018	11.6%	25.5%	2.3%	10.6%	6.4%	7.6%	6.8%	10.0%	2.7%	10.3%	0.8%	5.8%	9.6%	20.3%	6.2%	14.6%
2019	10.8%	23.3%	2.0%	11.4%	5.0%	8.6%	8.0%	10.8%	1.6%	9.8%	0.7%	6.3%	9.6%	20.5%	5.5%	14.1%
2020	8.6%	21.1%	4.5%	10.9%	4.2%	6.7%	7.8%	9.1%	5.2%	9.7%	1.6%	6.0%	17.0%	19.3%	6.2%	12.8%
2021	11.2%	27.7%	3.6%	12.8%	5.2%	10.4%	10.7%	12.3%	9.0%	12.8%	0.9%	6.4%	18.2%	20.2%	6.9%	15.8%
2022	13.3%	30.0%	4.3%	14.1%	5.7%	9.7%	13.2%	15.0%	3.8%	11.4%	1.4%	6.8%	16.5%	19.0%	7.5%	16.4%
2023	11.5%	27.0%	4.0%	15.1%	5.4%	9.5%	15.2%	16.5%	4.5%	18.6%	0.5%	5.8%	6.1%	19.0%	5.6%	15.5%
2024	8.1%	23.1%	3.9%	13.1%	6.5%	8.9%	12.2%	11.8%	4.1%	19.7%	1.0%	7.4%	7.6%	16.8%	5.0%	14.0%
Average	10.9%	24.2%	3.4%	12.5%	7.2%	8.7%	9.6%	11.0%	4.0%	12.4%	1.2%	6.8%	11.8%	20.6%	6.7%	15.0%

¹⁸² OAT, 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.¹⁸³ 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 3.4 percent in the first nine months of 2024. Table 5-35 shows the causes of EFOF by unit type. Forced outages for boiler tube leaks, 14.2 percent of the system EFOF, were the largest single contributor to average system EFOF across all unit types.

Table 5-35 Contribution to PJM EFOF by unit type by cause: January through September, 2024

	Combined		Combustion		Hydroelectric	Nuclear	Other	System
	Coal	Cycle	Turbine	Diesel				
Boiler Tube Leaks	29.2%	2.8%	0.0%	0.0%	0.0%	0.0%	9.7%	14.2%
Unit Testing	4.7%	7.9%	23.1%	18.3%	57.7%	15.2%	18.8%	13.5%
Generator	4.7%	25.8%	1.9%	1.8%	2.3%	0.0%	0.0%	7.0%
Electrical	6.3%	4.7%	9.4%	28.0%	0.1%	1.0%	4.0%	5.7%
Boiler Air and Gas Systems	7.0%	1.0%	0.0%	0.0%	0.0%	0.0%	6.8%	3.9%
Circulating Water Systems	3.3%	10.8%	0.0%	0.0%	0.0%	2.6%	0.4%	3.5%
Boiler Tube Fireside Slagging or Fouling	7.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.4%	3.5%
Controls	3.2%	3.2%	1.1%	5.5%	0.1%	1.9%	5.6%	2.9%
Turbine	0.0%	0.5%	14.2%	0.0%	7.0%	0.0%	0.0%	2.7%
Miscellaneous (Steam Turbine)	1.9%	0.9%	0.0%	0.0%	0.0%	6.9%	11.0%	2.6%
Auxiliary Systems	2.2%	2.4%	4.8%	0.0%	0.1%	0.0%	2.2%	2.3%
Miscellaneous (Gas Turbine)	0.0%	1.3%	13.8%	0.0%	0.0%	0.0%	0.0%	2.3%
Fuel Quality	1.1%	0.0%	9.8%	2.7%	0.0%	0.0%	2.1%	2.2%
Boiler Piping System	4.0%	1.5%	0.0%	0.0%	0.0%	0.0%	0.7%	2.1%
Miscellaneous (Generator)	0.0%	5.3%	2.1%	14.3%	0.9%	4.1%	1.6%	1.9%
Condensing System	1.6%	0.3%	0.0%	0.0%	0.0%	3.4%	8.0%	1.8%
Personnel or Procedure Errors	3.8%	0.1%	0.0%	5.6%	0.0%	0.0%	0.1%	1.7%
Fuel, Ignition and Combustion Systems	0.0%	3.9%	6.4%	0.0%	0.0%	0.0%	0.0%	1.6%
Boiler Fuel Supply from Bunkers to Boiler	3.0%	0.4%	0.0%	0.0%	0.0%	0.0%	2.2%	1.6%
All Other Causes	16.1%	27.3%	13.3%	23.7%	31.7%	65.0%	26.6%	23.1%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

¹⁸³ 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 3.4 percent in the first nine months of 2024. Table 5-36 shows the causes of EMOF by unit type. Maintenance outages for boiler air and gas systems, 10.2 percent of the system EMOF, were the largest single contributor to average system EMOF across all unit types, although miscellaneous gas turbine issues were the largest contributors to EMOF for combustion turbines.

Table 5-36 Contribution to EMOF by unit type by cause: January through September, 2024

	Combined		Combustion		Hydroelectric	Nuclear	Other	System
	Coal	Cycle	Turbine	Diesel				
Boiler Air and Gas Systems	16.9%	0.0%	0.0%	0.0%	0.0%	0.0%	5.4%	10.2%
Miscellaneous (Reactor)	0.0%	0.0%	0.0%	0.0%	0.0%	65.4%	0.0%	8.8%
Electrical	7.1%	3.5%	13.6%	3.2%	35.5%	1.8%	1.5%	7.6%
Boiler Tube Leaks	6.1%	9.6%	0.0%	0.0%	0.0%	0.0%	33.6%	6.5%
Boiler Piping System	6.7%	16.3%	0.0%	0.0%	0.0%	0.0%	0.0%	5.2%
Miscellaneous (Balance of Plant)	6.0%	2.7%	10.2%	0.3%	0.3%	0.0%	8.1%	5.2%
Boiler Overhaul and Inspections	6.4%	0.0%	0.0%	0.0%	0.0%	0.0%	3.0%	3.9%
Cooling System	5.0%	7.5%	0.0%	0.5%	0.2%	0.0%	0.0%	3.5%
Miscellaneous (Gas Turbine)	0.0%	9.2%	29.9%	0.0%	0.0%	0.0%	0.0%	3.5%
Circulating Water Systems	5.4%	0.0%	0.0%	0.0%	0.0%	1.3%	0.8%	3.4%
Auxiliary Systems	3.0%	1.9%	13.1%	0.3%	0.0%	0.0%	2.6%	3.3%
Boiler Internals and Structures	4.4%	2.4%	0.0%	0.0%	0.0%	0.0%	3.4%	3.0%
Wet Scrubbers	5.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.9%
Miscellaneous (Steam Turbine)	2.8%	3.5%	0.0%	0.0%	0.0%	0.4%	1.9%	2.1%
Boiler Fuel Supply from Bunkers to Boiler	3.3%	0.1%	0.0%	0.0%	0.0%	0.0%	0.2%	1.9%
Boiler Tube Fireside Slagging or Fouling	3.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.8%	1.9%
Feedwater System	1.9%	0.9%	0.0%	0.0%	0.0%	1.0%	6.2%	1.7%
Reactor Coolant System	0.0%	0.0%	0.0%	0.0%	0.0%	12.4%	0.0%	1.7%
Condensing System	1.5%	1.4%	0.0%	0.0%	0.0%	2.6%	1.9%	1.5%
All Other Causes	15.3%	41.0%	33.2%	95.7%	64.0%	15.0%	30.7%	22.3%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

PJM EPOF was 7.2 percent in the first six months of 2024. Table 5-37 shows the causes of EPOF by unit type. Planned outages for miscellaneous balance of plant issues, 20.4 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.

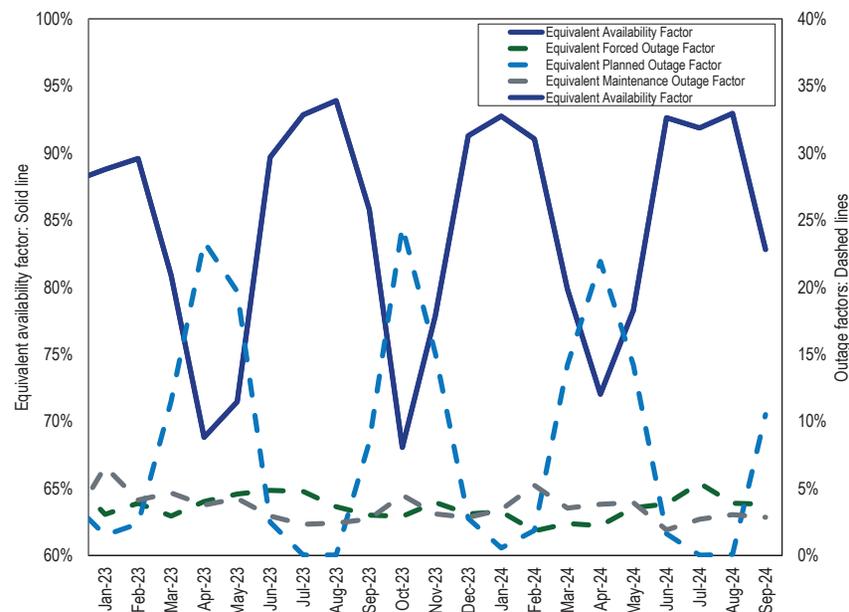
Table 5-37 Contribution to EPOF by unit type and cause: January through September, 2024

	Combined		Combustion		Hydroelectric	Nuclear	Other	System
	Coal	Cycle	Turbine	Diesel				
Miscellaneous (Balance of Plant)	30.2%	26.2%	15.8%	6.0%	0.1%	0.0%	33.8%	20.4%
Miscellaneous (Gas Turbine)	0.0%	45.1%	46.4%	0.0%	0.0%	0.0%	0.0%	15.4%
Core/Fuel	0.0%	0.0%	0.0%	0.0%	0.0%	97.7%	0.0%	14.9%
Boiler Overhaul and Inspections	13.4%	6.5%	0.0%	0.0%	0.0%	0.0%	32.8%	8.4%
Miscellaneous (Steam Turbine)	6.7%	11.2%	0.0%	0.0%	0.0%	0.0%	0.8%	4.8%
Miscellaneous (Generator)	7.4%	0.1%	2.2%	0.0%	14.9%	0.0%	0.0%	4.2%
Low Pressure Turbine	10.2%	1.6%	0.0%	0.0%	0.0%	0.0%	0.0%	3.8%
Generator	0.0%	0.6%	1.4%	0.1%	31.3%	0.0%	0.7%	3.4%
Turbine	0.0%	1.3%	0.8%	0.0%	21.0%	0.0%	0.0%	2.4%
Wet Scrubbers	6.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.2%
Valves	3.7%	0.5%	0.0%	0.0%	0.0%	0.0%	6.2%	1.8%
Electrical	0.0%	1.7%	9.2%	0.9%	0.6%	0.0%	1.8%	1.6%
Boiler Control Systems	4.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.5%
Miscellaneous	0.0%	0.0%	0.0%	0.0%	13.8%	0.4%	0.0%	1.4%
Miscellaneous (Boiler)	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	16.7%	1.3%
NOx Reduction Systems	3.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.3%
Continued Emissions Monitoring Systems (CEMS)	2.4%	0.0%	2.4%	0.0%	0.0%	0.0%	0.0%	1.1%
Boiler Piping System	2.3%	1.1%	0.0%	0.0%	0.0%	0.0%	0.0%	1.0%
Exciter	0.0%	0.0%	0.0%	0.0%	10.4%	0.0%	0.0%	1.0%
All Other Causes	8.9%	4.1%	21.8%	93.0%	8.1%	2.0%	7.2%	8.1%
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 September 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.¹⁸⁴ 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

¹⁸⁴ PJM. "PJM Manual 18: PJM Capacity Market," § 8.5 Summer/Winter Capability Testing, Rev. 57 (July 26, 2023).

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.¹⁸⁵ Wind and solar resources do not perform verification tests to prove capability.¹⁸⁶

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.¹⁸⁷

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.¹⁸⁸ Nine resources were assessed for generation resource rating test failure charges in the first nine months of 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

¹⁸⁵ PJM. "PJM Manual 18: PJM Capacity Market," § 8.5 Summer/Winter Capability Testing, Rev. 57 (July 26, 2023).

¹⁸⁶ PJM. "PJM Manual 18: PJM Capacity Market," Appendix B: Calculating Capacity Values for Wind and Solar Capacity Resources, Rev. 57 (July 26, 2023).

¹⁸⁷ "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 12, Section A.

¹⁸⁸ PJM. "PJM Manual 18: PJM Capacity Market," § 9.1.5 Generation Resource Rating Test Failure Charge, Rev. 57 (July 26, 2023).

in the resource's commitment plus the greater of 20 percent of that clearing price or 20 dollars per MW-day.¹⁸⁹

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.¹⁹⁰ 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.¹⁹¹ There were no such charges assessed in 2023 or in the first nine 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.¹⁹² Failure to meet this commitment can result in a Daily Capacity Resource Deficiency Charge.¹⁹⁴ 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,

¹⁸⁹ OATT, Attachment DD (Reliability Pricing Model) § 7.

¹⁹⁰ OATT, Attachment DD (Reliability Pricing Model) § 10A.

¹⁹¹ 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>>.

¹⁹² "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," § 1.3.6 Impacts of Test Results, Rev. 18 (July 26, 2023, 1, 2021).

¹⁹³ OATT, Attachment DD (Reliability Pricing Model) § 7 (a).

¹⁹⁴ PJM, "PJM Manual 18: PJM Capacity Market," § 8.2 RPM Commitment Compliance, Rev. 57 (July 26, 2023).

¹⁹⁵ OATT, Attachment DD (Reliability Pricing Model) § 8.

64 resources were assessed for deficiency charges in 2022, 175 resources were assessed for deficiency charges in 2023, and 429 resources were assessed for deficiency charges in the first nine 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 5-38 shows that from 2014 through September 2024, of all the changes in outage status, 96.3 percent of the outages and 87.4 percent of the outage MWh were changed from either planned or maintenance to forced outage status. Of those changes to forced outage status, 41.4 percent of the outages and 85.2 percent of the MWh were for coal and hydro plants.

Table 5-38 Changed outages by unit type: 2014 through September 2024¹⁹⁶

Unit Type	Year	Maintenance or Planned					
		Forced to Maintenance		Forced to Planned		to Forced	
		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-Sep)	1	18,908	0	NA	0	NA
	Total	14	805,898	0	NA	233	5,736,526
	Combined Cycle	2014	1	3,803	2	1,105	1
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-Sep)		3	2,625	0	NA	0	NA
Total		10	37,315	11	373,648	89	743,650
Combustion Turbine		2014	9	26,990	3	15,027	22
	2015	0	NA	0	NA	13	27,567
	2016	0	NA	0	NA	48	55,233
	2017	0	NA	0	NA	19	29,586
	2018	0	NA	2	41,737	25	24,433
	2019	0	NA	1	340	28	37,483
	2020	0	NA	0	NA	27	41,312
	2021	0	NA	0	NA	5	25,094
	2022	0	NA	0	NA	5	25,497
	2023	0	NA	0	NA	4	270,336
	2024 (Jan-Sep)	0	NA	0	NA	2	385
	Total	9	26,990	6	57,104	198	562,791
	Diesel	2014	0	NA	0	NA	77
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-Sep)		0	NA	0	NA	0	NA
Total		28	6,147	0	NA	1,300	82,408

Unit Type	Year	Maintenance or Planned					
		Forced to Maintenance		Forced to Planned		to Forced	
		No. Outages	MWh	No. Outages	MWh	No. Outages	MWh
Hydroelectric	2014	1	3	0	NA	124	1,383,319
	2015	1	162	0	NA	152	952,608
	2016	4	780	0	NA	315	1,433,851
	2017	2	52,080	0	NA	123	598,766
	2018	4	82,395	0	NA	72	405,549
	2019	0	NA	0	NA	34	148,629
	2020	0	NA	0	NA	59	281,976
	2021	0	NA	0	NA	33	263,525
	2022	0	NA	0	NA	1	4,887
	2023	0	NA	0	NA	9	196,512
	2024 (Jan-Sep)	0	NA	0	NA	0	NA
	Total	12	135,420	0	NA	922	5,669,622
	Nuclear	2014	0	NA	1	177,618	0
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-Sep)		0	NA	0	NA	0	NA
Total		0	NA	2	178,191	2	22,903
Other		2014	5	103,981	0	NA	1
	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-Sep)	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
2015		18	24,894	1	573	377	2,042,463
2016		6	283,764	1	65,664	696	3,783,728
2017		11	209,328	1	28,636	396	2,366,397
2018		11	91,901	2	41,737	379	1,324,165
2019		3	199,897	2	8,998	363	983,612
2020		3	8,898	0	NA	280	624,398
2021		3	137	7	303,061	41	315,679
2022		4	5,492	1	3,817	18	30,896
2023		3	30,234	0	NA	13	466,848
2024 (Jan-Sep)		4	21,533	0	NA	2	385
Total		87	1,280,903	21	646,237	2791	13,384,032

¹⁹⁶ Year describes the year in which the outage started and not the year in which the outage designation was changed.

