

Capacity Market

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

The Market Monitoring Unit (MMU) analyzed market structure, participant conduct and market performance in the PJM Capacity Market, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.¹ The conclusions are a result of the MMU's evaluation of the 2022/2023 Base Residual Auction.

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 region failed the three pivotal supplier test (TPS), which is conducted at the time of the auction.² 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.³
- Participant behavior was evaluated as not competitive in 2022/2023 RPM Base Residual Auction. 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. But the Net CONE times B offer cap under the capacity performance design exceeds the competitive level. In the 2022/2023 RPM Base Residual Auction, some participants' offers were above the competitive level. The MMU recognizes that these market participants followed the capacity market rules by offering at less than the stated offer cap of Net CONE times B. But Net CONE times B is not a competitive offer when the expected number of performance assessment intervals is zero or a very small number and the nonperformance charge rate is defined as Net CONE/30, and the other strong CP assumptions are also not correct. Under these circumstances, a competitive offer is net ACR. That is the way in which most market participants offered in this and prior capacity performance auctions. The Commission recognized this issue 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. But the 2022/2023 BRA was conducted with the previous default MSOC of Net CONE times B.⁴

- Market performance was evaluated as not competitive based on the 2022/2023 RPM Base Residual Auction. Although structural market power exists in the capacity market, a competitive outcome can result from the application of market power mitigation rules. The outcome of the 2022/2023 RPM Base Residual Auction was not competitive as a result of participant behavior which was not competitive, specifically offers which exceeded the competitive level.
- Market design was evaluated as mixed because while there are many positive features of the Reliability Pricing Model (RPM) design and the capacity performance modifications to RPM, there are several features of the RPM design which still threaten competitive outcomes. These include the definition of DR which permits inferior products to substitute for capacity, the replacement capacity issue, the definition of unit offer parameters, and

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 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.

³ 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.

⁴ 176 FERC ¶ 61,137 (September 2, 2021).

the inclusion of imports which are not substitutes for internal capacity resources.

- As a result of the fact that the capacity market design was found to be not just and reasonable by FERC and a final market design had not been approved, the 2022/2023 Base Residual Auction was delayed and held in May 2021, and for a number of additional reasons, the 2023/2024 Base Residual Auction is delayed and scheduled for June 2022, and first and second incremental auctions for the 2022/2023 through 2026/2027 Delivery Years are canceled if within 10 months of the revised BRA schedule.⁵

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 mandatory participation by load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand-side resources.⁶

Under RPM, capacity obligations are annual.⁷ Base Residual Auctions (BRA) are held for delivery years that are three years in the future. First, Second and Third Incremental Auctions (IA) are held for each delivery year.⁸ First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.⁹ 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.¹⁰

The 2021/2022 RPM Third Incremental Auction and the 2022/2023 RPM Base Residual Auction were conducted in 2021.

RPM prices are locational and may vary depending on transmission constraints and local supply and demand conditions.¹¹ Existing generation capable of qualifying as a capacity resource must be offered into RPM auctions, except for resources owned by entities that elect the fixed resource requirement (FRR) option. Participation by LSEs is mandatory, except for those entities that elect the FRR option. There is an administratively determined demand curve that defines scarcity pricing levels and that, with the supply curve derived from capacity offers, determines market prices in each BRA. RPM rules provide performance incentives for generation, including the requirement to submit generator outage data and the linking of capacity payments to the level of unforced capacity, and the performance incentives have been strengthened significantly under the Capacity Performance modifications to RPM. Under RPM there are explicit market power mitigation rules that define the must offer requirement, that define structural market power based on the marginal cost of capacity, that define offer caps, that define the minimum offer price, and that have flexible criteria for competitive offers by new entrants. Market power mitigation is effective only when these definitions are up to date and accurate. Demand resources and energy efficiency resources may be offered directly into RPM auctions and receive the clearing price without mitigation.

Market Structure

- **RPM Installed Capacity.** In 2021, RPM installed capacity increased 2,348.4 MW or 1.3 percent, from 184,245.0 MW on January 1, to 186,593.4 MW on December 31. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- **Reserves.** The sum of cleared MW that did not have a must offer requirement and the cleared MW of DR is 16,823.3 MW, or 100.7 percent of required reserves and 69.0 percent of total reserves. These results suggest that the required reserve margin and the actual reserve margin be considered carefully along with the obligations of the resources that the reserve margin assumes will be available.

5 174 FERC ¶ 61,036 (2021), 177 FERC ¶ 61,050 (2021), 177 FERC ¶ 61,209 (2021).

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

7 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.

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

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

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

11 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.

- **RPM Installed Capacity by Fuel Type.** Of the total installed capacity on December 31, 2021, 46.3 percent was gas; 26.0 percent was coal; 17.3 percent was nuclear; 4.7 percent was hydroelectric; 3.0 percent was oil; 1.4 percent was wind; 0.3 percent was solid waste; and 1.0 percent was solar.
- **Market Concentration.** In the 2021/2022 RPM Third Incremental Auction and the 2022/2023 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.¹² Offer caps were applied to all sell offers for resources which were subject to mitigation when the capacity market seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.^{13 14 15}
- **Imports and Exports.** Of the 1,558.0 MW of imports in the 2022/2023 RPM Base Residual Auction, 1,558.0 MW cleared. Of the cleared imports, 954.9 MW (61.3 percent) were from MISO.
- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs was 12,115.9 MW for June 1, 2021, as a result of cleared capacity for demand resources and energy efficiency resources in RPM auctions for the 2021/2022 Delivery Year (16,233.9 MW) less purchases of replacement capacity (4,118.0 MW).

Market Conduct

- **2021/2022 RPM Third Incremental Auction.** Of the 481 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for zero generation resources (0.0 percent).
- **2022/2023 RPM Base Residual Auction.** Of the 1,083 generation resources that submitted Capacity Performance offers, the MMU calculated unit

specific offer caps for zero generation resources (0.0 percent).

Market Performance

- The 2021/2022 RPM Third Incremental Auction and 2022/2023 RPM Base Residual Auction were conducted in 2021.¹⁶ The weighted average capacity price for the 2020/2021 Delivery Year is \$111.07 per MW-day, including all RPM auctions for the 2020/2021 Delivery Year. The weighted average capacity price for the 2021/2022 Delivery Year is \$147.33 per MW-day, including all RPM auctions for the 2021/2022 Delivery Year.
- For the 2021/2022 Delivery Year, RPM annual charges to load are \$9.4 billion.
- In the 2022/2023 RPM Base Residual Auction, the market performance was determined to be not competitive as a result of noncompetitive offers that affected market results.

Reliability Must Run Service

- Of the seven companies (23 units) that have provided RMR service, two companies (seven units) filed to be paid for RMR service under the deactivation avoidable cost rate (DACR), the formula rate. The other five companies (16 units) filed to be paid for RMR service under the cost of service recovery rate. PJM has indicated to another plant that RMR service will be required in 2022.

Generator Performance

- **Forced Outage Rates.** The average PJM EFORD in 2021 was 7.3 percent, an increase from 6.3 percent in 2020.¹⁷
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor in 2021 was 81.7 percent, a decrease from 84.7 percent in 2020.

¹² 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).

¹³ See OATT Attachment DD § 6.5.

¹⁴ 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).

¹⁵ 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).

¹⁶ FERC granted PJM's request for waiver of its Open Access Transmission Tariff to delay the 2022/2023 RPM Base Residual Auction from May 2019 to August 2019. See 164 FERC ¶ 61,153 (2018). FERC subsequently denied PJM's motion seeking clarification of the June 29, 2018, Order (163 FERC ¶ 61,236) and directed PJM not to run the 2022/2023 BRA in August 2019. See 168 FERC ¶ 61,051 (2019).

¹⁷ 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 January 24, 2022. 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.

Recommendations¹⁸

Definition of Capacity

- The MMU recommends the enforcement of a consistent definition of capacity resource. The MMU recommends that the 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.^{19 20} (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 on the supply side of the capacity market, because PJM's load forecasts now account for future EE, unlike the situation when EE was first added to the capacity market. EE should not be part of the capacity market. If EE is not included on the supply side, there is no reason to have an addback mechanism. If EE remains on the supply side, the MMU recommends that the implementation of the EE addback mechanism be modified to ensure that market clearing prices are not affected.²¹ (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that intermittent resources, including storage, not be permitted to offer capacity MW based on energy 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. (Priority: High. New recommendation. Status: Not adopted.)

- 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 storage resources, including hydro. The purpose of the must offer rule, which has been in place since the beginning of the capacity market in 1999, is to prevent the exercise of market power via withholding. (Priority: High. New recommendation. 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. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that the maximum price on the VRR curve be defined as net CONE. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that the test for determining modeled Locational Deliverability Areas (LDAs) in RPM be redefined. A detailed reliability analysis of all at risk units should be included in the redefined model. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM clear the capacity market based on nodal capacity resource locations and the characteristics of the transmission system consistent with the actual electrical facts of the grid. Absent a fully nodal capacity market clearing process, the MMU recommends that PJM use a non-nested model with all LDAs modeled including VRR curves for all LDAs. Each LDA requirement should be met with the capacity resources located within the LDA and exchanges from neighboring LDAs up to the transmission limit. LDAs should be allowed to price separate if that is the result of the LDA supply curves and the transmission constraints between LDAs. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that the net revenue calculation used by PJM to calculate the Net Cost of New Entry (CONE) VRR parameter reflect the actual

¹⁸ 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.

¹⁹ See also Comments of the Independent Market Monitor for PJM, Docket No. ER14-503-000 (December 20, 2013).

²⁰ 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).

²¹ Based on an Issue Charge introduced by the MMU, PJM has updated the EE addback rules effective with the 2023/2024 Delivery Year, to address this issue. "PJM Manual 18: PJM Capacity Market," § 2.4.5 Adjustments to RPM Auction Parameters for EE Resources, Rev. 51 (Oct. 20, 2021).

flexibility of units in responding to price signals rather than using assumed fixed operating blocks that are not a result of actual unit limitations.^{22 23} The result of reflecting the actual flexibility is higher net revenues, which affect the parameters of the RPM demand curve and market outcomes. (Priority: High. First reported 2013. Status: Adopted 2021.)

- 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, at much lower prices, 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 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 should 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. New recommendation. 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. New recommendation. Status: Not adopted.)

- 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. New recommendation. Status: Not adopted.)

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. New recommendation. Status: Not adopted.)
- The MMU recommends use of the Sustainable Market Rule (SMR) in order to protect competition in the capacity market from nonmarket revenues.²⁴ (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that, as part of the MOPR unit specific standard of review, all projects be required to use the same basic modeling assumptions. That is the only way to ensure that projects compete on the basis of actual costs rather than on the basis of modeling assumptions.²⁵ (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that modifications to existing resources be subject to market power related offer caps or MOPR offer floors and not be treated as new resources and therefore exempt. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the RPM market power mitigation rule be modified to apply offer caps

²⁴ Brief of the Independent Market Monitor for PJM, Docket No. EL16-49, ER18-1314-000, -001; EL18-178 (October 2, 2018).

²⁵ 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).

²² See PJM Interconnection, LLC, Docket No. ER12-513-000 (December 1, 2011) ("Triennial Review").
²³ See the 2019 State of the Market Report for PJM, Volume 2, Section 7: Net Revenue.

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 resources. (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 preferably at the same location, in order for the energy market and capacity market to remain synchronized and reliability metrics correctly calculated. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that the offer cap for capacity resources be defined as the net avoidable cost rate (ACR) of each unit so that the clearing prices are a result of such net ACR offers, consistent with the fundamental economic logic for a competitive offer of a CP resource. (Priority: High. First reported 2017. Status: Adopted, 2021.)
- 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.)

Performance Incentive Requirements of RPM

- The MMU recommends that any unit not capable of supplying energy equal to its day-ahead must offer requirement (ICAP) be required to reflect an appropriate outage. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that retroactive replacement transactions associated with a failure to perform during a PAI not be allowed and that, more generally, retroactive replacement capacity transactions not be permitted. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that there be an explicit requirement that capacity resource offers in the day-ahead energy market be competitive, where competitive is defined to be the short run marginal cost of the units. (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.)

Capacity Imports and Exports

- The MMU recommends that all capacity imports be required to be deliverable to PJM load in an identified LDA 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.)
- The MMU recommends clear, explicit and detailed rules that define the conditions under which PJM will and will not recall energy from PJM capacity resources and prohibit new energy exports from PJM capacity resources. The MMU recommends that those rules define the conditions under which PJM will purchase emergency energy while at the same time not recalling energy exports from PJM capacity resources. PJM has modified these rules, but the rules need additional clarification and operational details. (Priority: Low. First reported 2010. Status: Partially adopted.)

Deactivations/Retirements

- The MMU recommends that the notification requirement for deactivations be extended from 90 days prior to the date of deactivation to 12 months prior to the date of deactivation and that PJM and

the MMU be provided 60 days rather than 30 days to complete their reliability and market power analyses. (Priority: Low. First reported 2012. Status: Not adopted.)

- The MMU recommends that RMR units recover all and only the incremental costs, including incremental investment costs, required by the RMR service that the unit owner would not have incurred if the unit owner had deactivated its unit as it proposed. Customers should bear no responsibility for paying previously incurred costs, including a return on or of prior investments. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends elimination of the cost of service recovery rate in OATT Section 119, that RMR service should be provided under the deactivation avoidable cost rate in Part V, and that the revenue cap under the avoidable cost rate option be eliminated. The MMU also recommends specific improvements to the DACR provisions. (Priority: Medium. First reported 2017. Status: Not adopted.)

Conclusion

The analysis of PJM Capacity Markets begins with market structure, which provides the framework for the actual behavior or conduct of market participants. The analysis examines participant behavior within that market structure. In a competitive market structure, market participants are constrained to behave competitively. The analysis examines market performance, measured by price and the relationship between price and marginal cost, that results from the interaction of market structure and participant behavior.

The capacity market is, by design, always tight in the sense that total supply is generally only slightly larger than demand. The PJM Capacity Market is a locational market and local markets can and do have different supply demand balances than the aggregate market. While the market may be long at times, that is not the equilibrium state. Capacity in excess of demand is not sold and, if it does not earn or does not expect to earn adequate revenues in future capacity markets, or in other markets, or does not have value as a hedge, may be expected to retire, provided the market sets appropriate price signals to reflect the availability of excess supply. The demand for capacity includes expected peak load plus a reserve margin, and points on the demand curve,

called the Variable Resource Requirement (VRR) curve, exceed peak load plus the reserve margin. The shape of the VRR curve results in the purchase of excess capacity and higher payments by customers. The impact of the VRR curve shape used in the 2022/2023 BRA compared to a vertical demand curve was significant. The defined reliability goal is to have total supply greater than or equal to the defined demand for capacity. The level of purchased demand under RPM has generally exceeded expected peak load plus the target reserve margin, resulting in reserve margins that exceed the target. Demand for capacity is almost entirely inelastic because the market rules require loads to purchase their share of the system capacity requirement. The small level of elasticity incorporated in the RPM demand curve is not adequate to modify this conclusion. The result is that any supplier that owns more capacity than the typically small difference between total supply and the defined demand is individually pivotal and therefore has structural market power. Any supplier that, jointly with two other suppliers, owns more capacity than the difference between supply and demand either in aggregate or for a local market is jointly pivotal and therefore has structural market power.

The level of cleared demand resources (8,710.3 MW) is greater than the entire level of excess capacity cleared in the auction (7,660.2 MW). This is consistent with PJM effectively not relying on demand response for reliability in actual operations. The excess is a result of the flawed rules permitting the participation of inferior demand side resources in the capacity market. Maintaining the persistent excess has meant that PJM markets have never experienced the results of reliance on demand side resources as part of the required reserve margin, rather than as excess above the required reserve margin. PJM markets have never experienced the implications of the definition of demand side resources as a purely emergency capacity resource that triggers a PAI whenever called.

The market design for capacity leads to structural market power in the capacity market. The capacity market is unlikely ever to approach a competitive market structure in the absence of a substantial and unlikely structural change that results in much greater diversity of ownership. Market power is and will remain endemic to the structure of the PJM Capacity Market. Nonetheless a competitive outcome can be assured by appropriate

market power mitigation rules. Detailed market power mitigation rules are included in the PJM Open Access Transmission Tariff (OATT or Tariff). Reliance on the RPM design for competitive outcomes means reliance on the market power mitigation rules. Attenuation of those rules means that market participants are not able to rely on the competitiveness of the market outcomes. The market power rules applied in the 2021/2022 BRA and the 2022/2023 BRA were significantly flawed, as illustrated by the results of the 2021/2022 BRA and the 2022/2023 BRA.²⁶ Competitive outcomes require continued improvement of the rules and ongoing monitoring of market participant behavior and market performance. The incorrect definition of the offer caps in the 2021/2022 BRA and the 2022/2023 BRA resulted in noncompetitive offers and a noncompetitive outcome. The market power rules were corrected by the Commission in an order issued on September 2, 2021, (September 2nd Order) but the modified market power rules were not implemented in the 2022/2023 BRA.^{27 28} The result was that capacity market prices were above the competitive level. In addition, the inclusion of offers that were not consistent with the defined terms of the Minimum Offer Price Rule (MOPR) based on the MMU's review, but were accepted by PJM, had a significant impact on the auction results.

In the capacity market, as in other markets, market power is the ability of a market participant to increase the market price above the competitive level or to decrease the market price below the competitive level. In order to evaluate whether actual prices reflect the exercise of market power, it is necessary to evaluate whether market offers are consistent with competitive offers.

The definition of the market seller offer cap was changed with the introduction of the Capacity Performance (CP) rules. But the CP market seller offer cap was based on strong assumptions that are not correct. The CP market seller offer cap was significantly overstated as a result. For units that could profitably provide energy under the Capacity Performance design even without a capacity payment because their expected CP bonus payments exceed their net ACR, based on expected unit specific

performance, expected balancing ratio, expected performance assessment intervals (PAI) and expected penalty payments, the competitive, profit maximizing offer was defined to be Net CONE times B, where B is the expected average balancing ratio. This was the default offer cap for such units only under strong, defined assumptions.²⁹ Those assumptions included: there are expected PAI; the number of PAI used in the calculation of the nonperformance charge rate is the same as the expected PAI (360); penalties are imposed by PJM for all cases of noncompliance as defined in the tariff and there are no excuses; the bonus payments equal the penalties; and capacity resources have the ability to costlessly switch between energy only status and capacity resource status.

But those assumptions were not even close to being correct for the 2022/2023 BRA and Net CONE times B was not the correct offer cap as a result. The Capacity Performance paradigm has not worked as anticipated in PJM and is not expected to work, in part because the assumptions are never likely to be correct. In addition, PAI is an endogenous variable. The expected number of PAI is a function of the level of capacity resources which is a function of offers and the resultant clearing prices. The correct definition of a competitive offer is net ACR, where ACR includes an explicit accounting for the costs of mitigating risk, including the risk associated with capacity market nonperformance penalties.

The MMU concludes that the results of the 2022/2023 RPM Base Residual Auction were not competitive as a result of economic withholding by resources that used offers that were consistent with the Net CONE times B offer cap but not consistent with competitive offers based on the correctly calculated offer cap. The MMU recognizes that these market participants followed the capacity market rules by offering at less than the stated offer cap of Net CONE times B. A competitive offer in the capacity market is equal to net ACR.³⁰ That is the way in which most market participants offered in this and prior capacity performance auctions. The ACR values used in this analysis were based on data provided by the participants and were consistent with competitive offers

²⁶ 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).

²⁷ Complaint of the Independent Market Monitor for PJM, Docket No. EL19-47, February 21, 2019s ("IMM MSOC Complaint").

²⁸ 176 FERC ¶ 61,137 (September 2nd Order).

²⁹ For a detailed derivation, see Errata to February 25, 2015 Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM Interconnection, L.L.C., Docket No. ER15-623, et al. (February 27, 2015).

³⁰ See 174 FERC ¶ 61,212 at P 65 ("March 18th Order").

for the relevant capacity and were consistent with PJM's posted default ACR values for the referenced technology.

The MMU also concludes that market prices were significantly affected by other flaws in the capacity market rules and in the application of the capacity market rules by PJM, including the shape of the VRR curve, the overstatement of the capacity of intermittent resources, the treatment of DR, the MOPR rules, the inclusion of EE, and the EE addback rules.

The MMU also concludes that, although a much smaller issue in the 2022/2023 auction, the rules permitted the exercise of market power without mitigation for seasonal resources through uplift payments for noncompetitive offers, rather than through higher prices.³¹ Although the impact was small in the 2022/2023 auction, the issue should be addressed immediately in order to prevent the impact from increasing and because the solution is simple.

The recent changes to the capacity market design have addressed some but not all of the significant recommendations made by the MMU in prior reports. The MMU had recommended the elimination of the 2.5 percent demand adjustment (Short-Term Resource Procurement Target). The MMU had recommended that the performance incentives in the capacity market design be strengthened. The MMU had recommended that generation capacity resources pay penalties if they fail to produce energy when called upon during any of the hours defined as critical. The MMU had recommended that the net revenue calculation used by PJM to calculate the net Cost of New Entry (CONE) VRR parameter reflect the actual flexibility of units in responding to price signals rather than using assumed fixed operating blocks that are not a result of actual unit limitations. The MMU had recommended that all capacity imports be required to be pseudo tied in order to ensure that imports are as close to full substitutes for internal, physical capacity resources as possible. The MMU had recommended that the definition of demand side resources be modified in order to ensure that such resources are full substitutes for and provide the same value in the capacity market as generation resources,

although this recommendation has not been incorporated in PJM rules. The MMU had recommended that both the Limited and the Extended Summer DR products be eliminated and that the restrictions on the availability of Annual DR be eliminated in order to ensure that the DR product has the same unlimited obligation to provide capacity year round as Generation Capacity Resources. The MMU had recommended that the default Avoidable Cost Rate (ACR) escalation method be modified in order to ensure accuracy and eliminate double counting.

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.^{32 33 34 35 36 37} In 2020 and 2021, the MMU prepared a number of RPM related reports and testimony, shown in Table 5-2.

The PJM markets have worked to provide incentives to entry and to retain capacity. PJM had excess reserves of 7,828.5 ICAP MW on June 1, 2021, and will have excess reserves of 8,065.8 ICAP MW on June 1, 2022, based on current positions.³⁸ A majority of capacity investments in PJM were financed by market sources.³⁹ Of the 42,969.5 MW of additional capacity that cleared in RPM auctions for the 2007/2008 through 2021/2022 Delivery Years, 31,509.2 MW (73.3 percent) were based on market funding. Of the 6,587.3 MW of additional capacity that cleared in RPM auctions for the 2022/2023 through 2023/2024 Delivery Years, 4,924.2 MW (74.8 percent)

³¹ PJM uses various terms for uplift including make whole payments (often used in the capacity market) and operating reserve payments (often used in the energy market). The term uplift is used in this report to refer to out of market payments made by PJM to market participants in addition to market revenues.

³² 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).

³³ 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).

³⁴ 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).

³⁵ 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).

³⁶ 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).

³⁷ 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).

³⁸ The calculated reserve margin for June 1, 2022, does not account for cleared buy bids that have not been used in replacement capacity transactions.

³⁹ "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).

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

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

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

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

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

Table 5-2 RPM related MMU reports: January 2021 through February 25, 2022

Date	Name
January 29, 2021	Analysis of NJ Zero Emissions Credit(ZEC)Applications https://www.monitoringanalytics.com/reports/Reports/2021/IMM_Public_Report_Analysis_of_NJ_ZEC_Applications_20210129.pdf
February 19, 2021	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2021/2022 and 2022/2023 Delivery Years https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_RPM_Must_Offer_Obligations_20210219.pdf
March 4, 2021	Next Steps in Capacity Market Design https://www.monitoringanalytics.com/reports/Presentations/2021/IMM_Capacity_Market_Workshop_Session_2_Next_Steps_in_Capacity_Market_Design_20210304.pdf
March 5, 2021	IMM Comment re New Jersey FRR Docket No. E020030203 https://www.monitoringanalytics.com/filings/2021/IMM_Comment_Docket_No_E020030203_20210305.pdf
March 22, 2021	IMM Comments re ELCC Docket No. ER21-278-001 https://www.monitoringanalytics.com/filings/2021/IMM_Comments_Docket_No_ER21-278-001_20210322.pdf
March 31, 2021	IMM Answer re Jackson Complaint Docket No. EL21-62, et al https://www.monitoringanalytics.com/filings/2021/IMM_Answer_Docket_Nos_EL21-62_EL21-63_20210331.pdf
April 7, 2021	RPM Capacity Transfer Rights: Education https://www.monitoringanalytics.com/reports/Presentations/2021/IMM_MIC_RPM_Capacity_Transfer_Rights_Education_20210407.pdf
April 12, 2021	IMM Comments re Jackson Complaint Docket No. EL21-62, et al https://www.monitoringanalytics.com/filings/2021/IMM_Comments_Docket_Nos_EL21-62_EL21-63_20210412.pdf
April 19, 2021	IMM Answer to P3 re MSOC Docket Nos. EL19-47-001, et al https://www.monitoringanalytics.com/filings/2021/IMM_Answer_Docket_No_EL19-47_et_al_20210419.pdf
April 26, 2021	IMM Comments re Modernizing Electricity Market Design Docket No. AD21-10 https://www.monitoringanalytics.com/filings/2021/IMM_Post_Technical_Conference_Comments_Docket_No_AD21-10_20210426.pdf
April 28, 2021	IMM Brief re MSOC Docket No. EL19-47 and EL19-63 https://www.monitoringanalytics.com/filings/2021/IMM_Brief_Docket_No_EL19-47_et_al_20210428.pdf
April 29, 2021	IMM Answer to PJM re ELCC Docket No. ER21-278 https://www.monitoringanalytics.com/filings/2021/IMM_Answer_to_PJM_Docket_No_ER21-278_20210429.pdf
May 18, 2021	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2022/2023 Delivery Year https://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_RPM_Must_Offer_Obligations_20210518.pdf
May 19, 2021	IMM Answer to Motion re ELCC Docket No. EL19-100 and ER20-584 https://www.monitoringanalytics.com/filings/2021/IMM_Answer_to_Motion_Docket_No_EL19-100_20210519.pdf
May 25, 2021	IMM Comments re PJM Capacity Market CRF Docket No. ER21-1844 https://www.monitoringanalytics.com/filings/2021/IMM_Comments_Docket_No_ER21-1844_20210525.pdf
June 9, 2021	IMM Reply Brief re MSOC Docket No. EL19-47 and EL19-63 https://www.monitoringanalytics.com/filings/2021/IMM_Reply_Brief_Docket_No_EL19-47_EL19-63_20210609.pdf
June 15, 2021	IMM Response to Exelon re 10 Year Report Case No. 9271 https://www.monitoringanalytics.com/filings/2021/IMM_Response_to_Exelon_MDPSC_Case_No_%209271_20210615.pdf
June 16, 2021	IMM MOPR Matrix Entries https://www.monitoringanalytics.com/reports/Presentations/2021/IMM_MOPR_Matrix_Entries_20210616.pdf
June 22, 2021	IMM Comments re ELCC Docket No. ER21-2043 https://www.monitoringanalytics.com/filings/2021/IMM_Comment_Docket_No_ER21-2043_20210622.pdf
June 25, 2021	IMM Answer to Replies re MSOC Docket No. EL19-47 and EL19-63 https://www.monitoringanalytics.com/filings/2021/IMM_Answer_Docket_No_EL19-47_20210625.pdf
June 28, 2021	Data Submission Window Opening: 2023/2024 Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Opening_2023-2024_BRA_20210628.pdf
June 30, 2021	IMM MOPR Matrix Entries https://www.monitoringanalytics.com/reports/Presentations/2021/IMM_CIFP_MOPR_Matrix_Entries_20210630.pdf
August 11, 2021	EE Addback Issue https://www.monitoringanalytics.com/reports/Presentations/2021/IMM_MIC_EE_Addback_Issue_20210811.pdf
August 11, 2021	EE Addback Issue Charge Revised https://www.monitoringanalytics.com/reports/Presentations/2021/IMM_MIC_EE_Addback_Issue_Charge_Rev%2020210811.pdf
August 27, 2021	Quadrennial Review Issues https://www.monitoringanalytics.com/reports/Presentations/2021/IMM_MIC_Quad_Review_Issues_20210827.pdf
September 2, 2021	IMM Determinations Posted for the PJM 2023/2024 RPM Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Determinations_on_RPM_Requests_2023-2024_Base_Residual_Auction_20210902.pdf
September 13, 2021	Data Submission Window Reopening: 2023/2024 Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Reopening_2023_2024_Base_Residual_Auction_20210913.pdf
September 17, 2021	IMM Informational Session on MSOC https://www.monitoringanalytics.com/reports/Presentations/2021/IMM_MIC_MSOC_Net_ACR_%20Informational_Session_on_MSOC_20210917.pdf
September 22, 2021	IMM Answer to Comments re MOPR Docket No. ER21-2582 https://www.monitoringanalytics.com/filings/2021/IMM_Answer_to_Comments_Docket_No_ER21-2582_20210922.pdf
September 23, 2021	Market Seller Offer Cap (MSOC) Information https://www.monitoringanalytics.com/reports/Presentations/2021/IMM_MIC_MSOC_ACR_Market_Seller_Offer_Cap_20210923.pdf
September 27, 2021	IMM MOPR Review: PA House Environmental Resources & Energy Committee https://www.monitoringanalytics.com/reports/Presentations/2021/IMM_PA_House_E_and_E_MOPR_Review_20210927.pdf
September 28, 2021	Capacity Market Phase 2 Issues https://www.monitoringanalytics.com/reports/Presentations/2021/IMM_MIC_Capacity_Market_Workshop_20210928.pdf
September 29, 2021	Data Submission Window Reopening for the 2023/2024 RPM Base Residual Auction - Updated https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Reopening_20232024_BRA_Updated.pdf
September 30, 2021	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2022/2023 and 2023/2024 Delivery Years https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Notice_RPM_Must_Offer_Obligations_20210930.pdf
October 5, 2021	Data Submission Window Opening for the 2022/2023 RPM Third Incremental Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Opening_20222023_Third_Incremental_Auction_20211005.pdf

Table 5-2 RPM related MMU reports: January 2021 through February 25, 2022 (continued)

Date	Name
October 6, 2021	Data Submission Window Opening for the 2022/2023 RPM Third Incremental Auction – Updated https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Opening_%2020222023_Third_Incremental_Auction_20211005-Updated.pdf
October 12, 2021	IMM Motion for Clarification re MSOC Docket No. EL19-47, et al https://www.monitoringanalytics.com/filings/2021/IMM_Motion_for_Clarification_Docket_No_EL19-47_et_al_20211012.pdf
October 20, 2021	IMM Answer to PJM re RGGI Docket No. EL19-47, et al https://www.monitoringanalytics.com/filings/2021/IMM_Answer_Docket_No_EL19-47_et_al_20211020.pdf
October 22, 2021	Capacity Market Phase 2 Issues https://www.monitoringanalytics.com/reports/Presentations/2021/IMM_RASTF_Capacity_Market_Workshop_202101022.pdf
October 22, 2021	IMM Comments re SOO Green Capacity Complaint Docket No. EL21-103 https://www.monitoringanalytics.com/filings/2021/IMM_Comments_Docket_No_EL21-103_20211022.pdf
October 23, 2021	Unit Specific Net Revenue Calculation (Dispatchable Units) https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Net_Revenue_Calculation_2023_2024_Base_Residual_Auction_20211023.pdf
October 30, 2021	IMM Determinations Posted for the PJM 2023/2024 RPM Base Residual Auction – Updated https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Determinations_on_RPM_Requests_2023-2024_Base_Residual_Auction_Revised_20211030.pdf
November 1, 2021	IMM Comments and Market Power Analysis re PSEG–ArLight Transaction Docket No. EC21-128 https://www.monitoringanalytics.com/filings/2021/IMM_Comments_Docket_No_EC21-128_20211101.pdf
November 5, 2021	Net Revenue Calculation Update 2023/2024 Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Unit_Specific_Net_Revenue_Calculation_Dispatchable_Units_20232024_BRA_20211105.pdf
November 12, 2021	Net Revenue Calculation Update 2023/2024 Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/IMM_Unit_Specific_Review_Dispatchable_Units_Update_2023_2024_BRA_20211112.pdf
November 18, 2021	IMM Motion for Clarification or Waiver re MSOC Deadlines Docket No. EL19-47, et al https://www.monitoringanalytics.com/filings/2021/IMM_Motion_for_Clarification_or_Waiver_Docket_No_EL19-47_20211118.pdf
November 19, 2021	IMM Comments re ArLight/PSEG Transaction Docket No. EC21-128 https://www.monitoringanalytics.com/filings/2021/IMM_Letter_Merger_Docket_No_EC21-128_20211119.pdf
November 23, 2021	Alternative MSOC Agreement Template https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Alternative_MSOC_Agreement_Template_20211123.docx
November 23, 2021	Alternative Market Seller Offer Caps for the PJM 2023/2024 RPM Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Alternative_MSOC_2023-2024_Base_Residual_Auction_20211123.pdf
November 30, 2021	IMM Determinations Posted for the PJM 2022/2023 RPM Third Incremental Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Determinations_on_RPM_Requests_2022-2023_Third_Incremental_Auction_20211130.pdf
December 1, 2021	IMM Answer to PJM re MSOC Docket No. EL19-47, et al https://www.monitoringanalytics.com/filings/2021/IMM_Answer_to_PJM_Answer_Docket_No_EL19-47_20211201.pdf
December 1, 2021	Data Submission Window Reopening for the 2023/2024 RPM Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Reopening_for_the_20232024_RPM_BRA_20211201.pdf
December 3, 2021	Data Submission Window Reopening- 2023/2024 RPM Base Residual Auction – Updated https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Reopening_%202023-2024_Base_Residual_Auction_Updated_20211203.pdf
December 29, 2021	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2022/2023 and 2023/2024 Delivery Years https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Notice_RPM_Must_Offer_Obligations_20211229.pdf
January 5, 2022	MSOC Issues https://www.monitoringanalytics.com/reports/Presentations/2022/IMM_RASTF_MSOC_Issues_20220110.pdf
January 7, 2021	Reactive Power Compensation and the Capacity Market https://www.monitoringanalytics.com/reports/Presentations/2022/IMM_RPCTF_Reactive_Power_Compensation_20220107.pdf
January 27, 2021	Data Submission Window Reopening for the 2023/2024 RPM Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Reopening_2023-2024_Base_Residual_Auction_Updated_20220127.pdf
February 4, 2022	Data Submission Window Reopening for the 2023/2024 RPM Base Residual Auction – Updated https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Reopening_20232024_Base_Residual_Auction_Updated_20220204.pdf
February 11, 2022	2022 Quadrennial Review: IMM Proposals and Results https://www.monitoringanalytics.com/reports/Presentations/2022/IMM_Quadrennial_Review_IMM_CONE_CT_CC_Study_20220211.pdf
February 22, 2022	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 25, 2022	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2022/2023 and 2023/2024 Delivery Years https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Notice_RPM_Must_Offer_Obligations_20220225.pdf

Installed Capacity

On January 1, 2021, RPM installed capacity was 184,245.0 MW (Table 5-3).⁴⁰ Over the next 12 months, new generation, unit deactivations, facility reratings, plus import and export shifts resulted in RPM installed capacity of 186,593.4 MW on December 31, 2021, an increase of 2,348.4 MW or 1.3 percent from the January 1 level.⁴¹ ⁴² The 2,348.4 MW increase was the result of new or reactivated generation (4,809.7 MW), capacity modifications (670.0 MW), an increase in imports (38.5 MW), offset by an increase in exports (154.9 MW), derates (228.9 MW), and deactivations (2,786.0 MW).

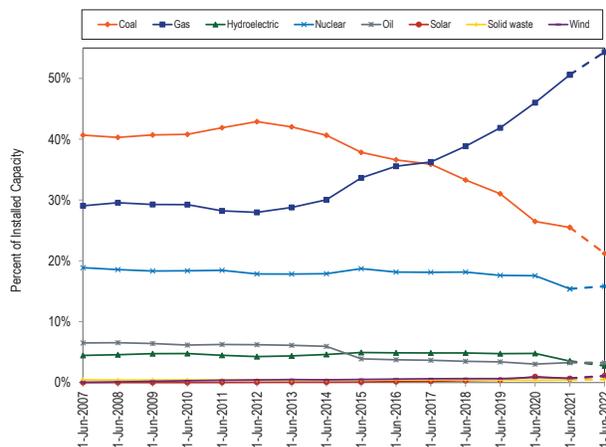
At the beginning of the new delivery year on June 1, 2021, RPM installed capacity was 183,962.3 MW, an increase of 1,024.4 MW or 0.6 percent from the May 31, 2021, level of 182,937.9 MW.

Table 5-3 Installed capacity (By fuel source): January 1, May 31, June 1, and December 31, 2021

	01-Jan-21		31-May-21		01-Jun-21		31-Dec-21	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	49,747.0	27.0%	49,340.2	27.0%	48,714.4	26.5%	48,568.4	26.0%
Gas	84,031.3	45.6%	83,914.1	45.9%	84,651.7	46.0%	86,321.3	46.3%
Hydroelectric	8,754.3	4.8%	8,753.5	4.8%	8,792.0	4.8%	8,792.0	4.7%
Nuclear	32,312.4	17.5%	32,301.2	17.7%	32,301.2	17.6%	32,301.2	17.3%
Oil	5,512.6	3.0%	5,507.1	3.0%	5,550.1	3.0%	5,545.5	3.0%
Solar	1,014.7	0.6%	1,051.1	0.6%	1,779.5	1.0%	1,824.0	1.0%
Solid waste	695.6	0.4%	650.5	0.4%	650.5	0.4%	650.5	0.3%
Wind	2,177.1	1.2%	1,420.2	0.8%	1,522.9	0.8%	2,590.5	1.4%
Total	184,245.0	100.0%	182,937.9	100.0%	183,962.3	100.0%	186,593.4	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, 2021, as well as the expected installed capacity for the 2022/2023 Delivery Year, based on the results of all auctions held through September 30, 2021.⁴³ On June 1, 2007, coal comprised 40.7 percent of the installed capacity, reached a maximum of 42.9 percent in 2012, decreased to 25.5 percent on June 1, 2021, and is projected to decrease to 21.2 percent by June 1, 2022. The share of gas increased from 29.1 percent on June 1, 2007, to 50.6 percent on June 1, 2021, and is projected to increase to 54.3 percent on June 1, 2022.

Figure 5-1 Percent of installed capacity (By fuel source): June 1, 2007 through June 1, 2022



⁴⁰ 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.

⁴¹ 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.

⁴² Wind resources accounted for 2,590.5 MW, and solar resources accounted for 1,824.0 MW of installed capacity in PJM on December 31, 2021. PJM administratively reduces 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 become available, unforced capability of wind and solar resources will 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. 15 (May 26, 2021). The derating approach will be replaced with ELCC.

⁴³ Due to EFORd values not being finalized for future delivery years, the projected installed capacity is based on cleared unforced capacity (UCAP) MW using the EFORd submitted with the offer.

Table 5-4 shows the RPM installed capacity on January 1, 2021, through December 31, 2021, 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 December 31, 2021⁴⁴

Parent Company	01-Jan-21			31-May-21			01-Jun-21			31-Dec-21		
	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
Exelon Corporation	20,843.6	12.2%	1	20,787.3	12.2%	1	20,747.0	12.2%	1	20,801.5	12.1%	1
Dominion Resources, Inc.	19,533.2	11.4%	2	19,505.1	11.5%	2	19,702.1	11.6%	2	19,702.1	11.4%	2
Vistra Energy Corp.	11,319.0	6.6%	3	11,319.0	6.7%	3	11,327.8	6.7%	3	11,327.8	6.6%	3
Riverstone Holdings LLC	10,941.4	6.4%	4	10,866.5	6.4%	5	10,914.8	6.4%	5	10,868.6	6.3%	5
LS Power Group	10,843.7	6.3%	5	11,053.7	6.5%	4	11,253.4	6.6%	4	11,253.4	6.5%	4

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, 2021, to December 31, 2021, by funding type.

Table 5-5 Installed capacity by funding type: January 1, May 31, June 1, and December 31, 2021⁴⁵

Funding Type	01-Jan-21		31-May-21		01-Jun-21		31-Dec-21	
	ICAP (MW)	Percent of Total ICAP						
Market	137,312.5	74.5%	136,106.1	74.4%	136,807.7	74.4%	139,462.8	74.7%
Nonmarket	46,932.5	25.5%	46,831.8	25.6%	47,008.6	25.6%	47,130.6	25.3%
Total	184,245.0	100.0%	182,937.9	100.0%	183,816.3	100.0%	186,593.4	100.0%

Fuel Diversity

Figure 5-2 shows the fuel diversity index (FDI_c) for RPM installed capacity.⁴⁶ 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. The fuel type categories used in the calculation of the FDI_c are the eight fuel sources in Table 5-3. 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.⁴⁷ 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.⁴⁸ The average FDI_c for 2021 decreased 0.3 percent compared to 2020. Figure 5-2 also includes the expected FDI_c through June 2022 based on cleared RPM auctions. The expected FDI_c is indicated in Figure 5-2 by the dashed orange line.

The FDI_c was used to measure the impact of potential retirements of resources that the MMU has identified as being at risk of retirement. A total of 2,230 MW of capacity were identified as being at risk of retirement.⁴⁹ Generation owners that intend to retire a generator are required by the tariff to notify PJM at least 90 days in advance of the retirement.⁵⁰ There are 7,081.0 MW of generation that have a requested retirement date after December 31, 2021.⁵¹ The dashed green line in Figure 5-2 shows the FDI_c calculated assuming that the capacity that cleared in an RPM auction

⁴⁴ The calculated MW for January 1, 2021, were revised from the 2021 Quarterly State of the Market Report for PJM: January through March.

⁴⁵ The calculated MW for January 1, 2021, were revised from the 2021 Quarterly State of the Market Report for PJM: January through March.

⁴⁶ Monitoring Analytics 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.

⁴⁷ 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 State of the Market Report for PJM for additional details.

⁴⁸ See the 2019 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.

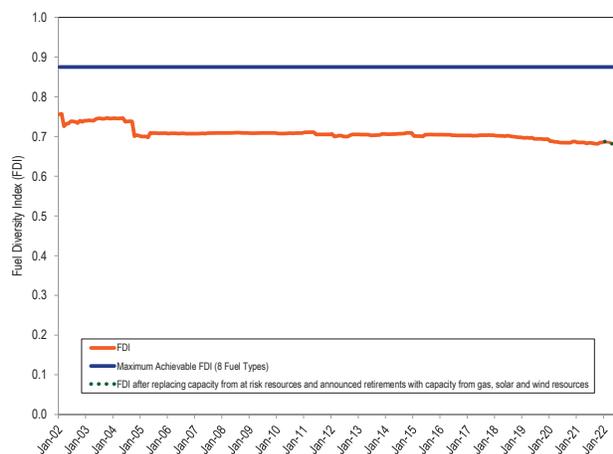
⁴⁹ See Table 7-47 in the 2021 State of the Market Report for PJM, Volume II, Section 7: Net Revenue.

⁵⁰ See OATT Part V § 113.1.

⁵¹ See Table 12-11 in the 2021 State of the Market Report for PJM, Volume II, Section 12: Generation and Transmission Planning.

from the at risk resources and other resources with deactivation notices is replaced by gas, wind and solar capacity.^{52 53} The FDI_c under these assumptions would decrease by 0.3 percent on average from the expected FDI_c for the period January 1, 2022, through June 1, 2022.

Figure 5-2 Fuel Diversity Index for installed capacity: January 1, 2002 through June 1, 2022



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 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.⁵⁴ In 2021, the 2021/2022 RPM Third Incremental

Auction and 2022/2023 RPM Base Residual Auction were conducted.⁵⁵

Market Structure

Supply

Table 5-6 shows generation capacity changes since the implementation of the Reliability Pricing Model through the 2020/2021 Delivery Year. The 19,278.5 MW increase was the result of new generation capacity resources (34,017.5 MW), reactivated generation capacity resources (1,374.4 MW), uprates (7,577.6 MW), integration of external zones (21,967.5 MW), a net decrease in capacity exports (2,016.8 MW), offset by a net decrease in capacity imports (1,051.5 MW), deactivations (42,972.0 MW) and derates (3,651.8 MW).

Table 5-7 shows the calculated RPM reserve margin and reserve in excess of the defined installed reserve margin (IRM) for June 1, 2018, through June 1, 2022, 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 EFORs for the delivery year are finalized, on November 30 in the year prior to the delivery year, but before the start of the delivery day. The calculated reserve margins for June 1, 2022, does not account for cleared buy bids that have not been used in replacement capacity transactions.

Future Changes in Generation Capacity⁵⁶

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 2020/2021

52 It is assumed that 1,458.4 MW of replacement capacity is from solar units and 133.7 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 7,669.5 GWh of generation over a one year period assuming the average capacity derate factors in the Planned Generation Additions subsection of Section 12 and the average capacity factors for wind and solar capacity resources in Table 8-27 and Table 8-30. This level of GWh represents the increase in renewable generation required by RPS in 2022 over the level of renewable generation that was required by RPS in 2021. The split between solar and wind is based on queue data.

53 For this analysis resources for which PJM has received deactivation notifications were replaced with capacity beginning on the projected retirement date listed in the deactivation data. At risk resources that have not notified PJM regarding deactivation were replaced with capacity beginning on July 1, 2021.

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

55 FERC granted PJM's request for waiver of its Open Access Transmission Tariff to delay the 2022/2023 RPM Base Residual Auction from May 2019 to August 2019. See 164 FERC ¶ 61,153 (2018). FERC subsequently denied PJM's motion seeking clarification of the June 29, 2018, Order (163 FERC ¶ 61,236) and directed PJM not to run the 2022/2023 BRA in August 2019. See 168 FERC ¶ 61,051 (2019).

56 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).

Delivery Year, internal installed capacity decreased by 3,654.3 MW after accounting for new capacity resources, reactivations, and uprates (42,969.5 MW) and capacity deactivations and derates (46,623.8 MW).

For the current and future delivery years (2021/2022 through 2022/2023), new generation capacity is defined as capacity that cleared an RPM auction for the first time in the specified delivery year. Based on expected completion rates of cleared new generation capacity (5,389.5 MW) and pending deactivations (6,911.4 MW), PJM capacity is expected to decrease by 1,521.9 MW for the 2021/2022 through 2022/2023 Delivery Years.

total reserves. The sum of cleared MW that did not have a must offer requirement and the cleared MW of DR is 16,823.3 MW, or 100.7 percent of required reserves and 69.0 percent of total reserves.

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

Table 5-6 Generation capacity changes: 2007/2008 through 2020/2021⁵⁷

	ICAP (MW)								
	New	Reactivations	Uprates	Integration	Net Change in Capacity Imports	Net Change in Capacity Exports	Deactivations	Derates	Net Change
2007/2008	45.0	0.0	691.5	0.0	70.0	15.3	380.0	417.0	(5.8)
2008/2009	815.4	238.3	987.0	0.0	473.0	(9.9)	609.5	421.0	1,493.1
2009/2010	406.5	0.0	789.0	0.0	229.0	(1,402.2)	108.4	464.3	2,254.0
2010/2011	153.4	13.0	339.6	0.0	137.0	367.7	840.6	223.5	(788.8)
2011/2012	3,096.4	354.5	507.9	16,889.5	(1,183.3)	(1,690.3)	2,542.0	176.2	18,637.1
2012/2013	1,784.6	34.0	528.1	47.0	342.4	84.0	5,536.0	317.8	(3,201.7)
2013/2014	198.4	58.0	372.8	2,746.0	934.3	28.9	2,786.9	288.3	1,205.4
2014/2015	2,276.8	20.7	530.2	0.0	2,335.7	177.3	4,915.6	360.3	(289.8)
2015/2016	4,291.8	90.0	449.0	0.0	511.4	(117.8)	8,338.2	215.8	(3,094.0)
2016/2017	3,679.3	532.0	419.2	0.0	575.6	722.9	659.4	206.7	3,617.1
2017/2018	4,127.3	5.0	562.1	0.0	(1,025.1)	(695.1)	2,657.4	148.5	1,558.5
2018/2019	8,127.5	4.0	330.9	2,120.0	(3,217.0)	212.7	6,730.0	89.2	333.5
2019/2020	4,612.0	13.3	494.9	165.0	(1,196.6)	401.3	3,296.0	116.8	274.5
2020/2021	403.1	11.6	575.4	0.0	(37.9)	(111.6)	3,572.0	206.4	(2,714.6)
Total	34,017.5	1,374.4	7,577.6	21,967.5	(1,051.5)	(2,016.8)	42,972.0	3,651.8	19,278.5

As shown in Table 5-7, total reserves on June 1, 2022, will be 24,373.5 MW, of which 7,660.2 MW are in excess of the required level of reserves, which is 16,713.3 MW. In the 2022/2023 BRA, 14,918.8 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 2,521.9 MW of intermittent and storage resources (1.7 percent of total cleared MW) were not offered in the 2022/2023 BRA.

The sum of cleared MW that were considered categorically exempt from the must offer requirement is 8,113.0 MW, or 48.5 percent of the required reserves and 33.3 percent of total reserves. The cleared MW of DR is 8,710.3 MW, or 52.1 percent of required reserves and 35.7 percent of

⁵⁷ The capacity changes in this report are calculated based on June 1 through May 31.

Table 5-7 RPM reserve margin: June 1, 2018, to June 1, 2022^{58 59}

	01-Jun-18	01-Jun-19	01-Jun-20	01-Jun-21	01-Jun-22	
Forecast peak load ICAP (MW)	152,407.9	151,643.5	148,355.3	149,482.9	150,229.0	A
FRR peak load ICAP (MW)	12,732.9	12,284.2	11,488.3	11,717.7	28,535.5	B
PRD ICAP (MW)	0.0	0.0	558.0	510.0	230.0	C
Installed reserve margin (IRM)	16.1%	16.0%	15.5%	14.7%	14.5%	D
Pool wide average EFORd	6.07%	6.08%	5.78%	5.22%	5.08%	E
Forecast pool requirement (FPR)	1.091	1.090	1.088	1.087	1.087	$F=(1+D)*(1-E)$
RPM committed less deficiency UCAP (MW) (generation and DR)	161,242.6	162,276.1	159,560.4	156,633.6	139,666.7	G
RPM committed less deficiency ICAP (MW) (generation and DR)	171,662.5	172,781.2	169,348.8	165,260.2	147,141.5	$H=G/(1-E)$
RPM peak load ICAP (MW)	139,675.0	139,359.3	136,309.0	137,255.2	121,463.5	$J=A-B-C$
Reserve margin ICAP (MW)	31,987.5	33,421.9	33,039.8	28,005.0	25,678.0	$K=H-J$
Reserve margin (%)	22.9%	24.0%	24.2%	20.4%	21.1%	$L=K/J$
Reserve margin in excess of IRM ICAP (MW)	9,499.8	11,124.4	11,911.9	7,828.5	8,065.8	$M=K-D*J$
Reserve margin in excess of IRM (%)	6.8%	8.0%	8.7%	5.7%	6.6%	$N=M/J$
RPM peak load UCAP (MW)	131,196.7	130,886.3	128,430.3	130,090.5	115,293.2	$P=J*(1-E)$
RPM reliability requirement UCAP (MW)	152,315.6	151,832.0	148,331.5	149,210.1	132,006.5	$Q=J*F$
Reserve margin UCAP (MW)	30,045.9	31,389.8	31,130.1	26,543.1	24,373.5	$R=G-P$
Reserve cleared in excess of IRM UCAP (MW)	8,927.0	10,444.1	11,228.9	7,423.5	7,660.2	$S=G-Q$
Projected replacement capacity UCAP (MW)	0.0	0.0	0.0	0.0	0.0	T
Projected reserve margin	22.9%	24.0%	24.2%	20.4%	21.1%	$U=(H-T/(1-E))/J-1$

Sources of Funding⁶⁰

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 2021/2022 Delivery Year totaled 35,391.9 MW (82.4 percent of all additions), with 26,320.6 MW from market funding and 9,071.3 MW from nonmarket funding. Upgrades to existing generation capacity from the 2007/2008 Delivery Year through the 2021/2022 Delivery Year totaled 7,577.6 MW (17.6 percent of all additions), with 5,188.6 MW from market funding and 2,389.0 MW from nonmarket funding. In summary, of the 42,969.5 MW of additional capacity from new, reactivated, and upgraded generation that cleared in RPM auctions for the 2007/2008 through 2021/2022 Delivery Years, 31,509.2 MW (73.3 percent) were based on market funding.

Of the 6,587.3 MW of the additional generation capacity (new resources, reactivated resources, and upgrades) that cleared in RPM auctions for the 2022/2023 through 2023/2024 Delivery Year, 3,644.4 MW are not yet in service. Of those 3,644.4 MW that have not yet gone into service, 2,244.6 MW have market funding and 1,399.8 MW have nonmarket funding. Applying the historical completion rates, 67.1 percent of all the projects in development are expected to go into service (1,483.2 MW of the 2,244.6 MW of in development market funded projects; 963.3 MW of the 1,399.8 MW of in development nonmarket funded projects). Together, 2,446.6 MW of the 3,644.4 MW of new generation capacity that cleared MW in RPM and are not yet in service are expected to go into service through the 2023/2024 Delivery Year.

Of the 2,942.9 MW of the additional generation capacity that cleared in RPM auctions for the 2022/2023 through 2023/2024 Delivery Years and are already in service, 2,679.8 MW (91.1 percent) are based on market funding and 263.1 MW (8.9 percent) are based on nonmarket funding. In summary, 4,924.2 MW (74.8 percent) of the additional generation capacity (2,244.6 MW not yet in service and 2,679.8 MW in service) that cleared in RPM auctions for the 2022/2023 through 2023/2024 Delivery Years are based on market funding. Capacity additions based on

⁵⁸ 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.

⁵⁹ These reserve margin calculations do not consider Fixed Resource Requirement (FRR) load.

⁶⁰ 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/JMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf> (September 15, 2020).

nonmarket funding are 1,662.9 MW (25.2 percent) of proposed generation that cleared at least one RPM auction for the 2022/2023 through 2023/2024 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:

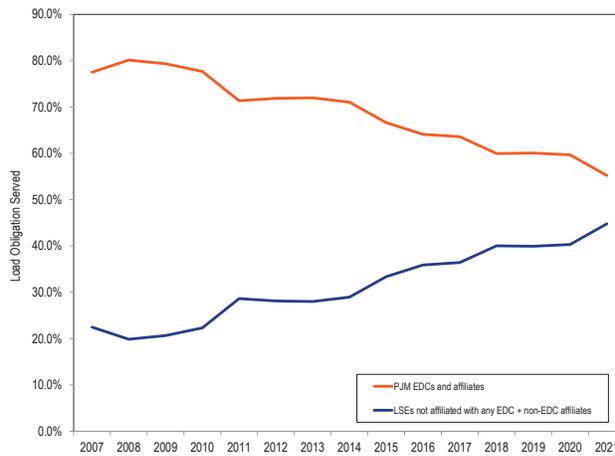
- **PJM EDC.** EDCs with a franchise service territory within the PJM footprint. This sector includes traditional utilities, electric cooperatives, municipalities and power agencies.
- **PJM EDC Generating Affiliate.** Affiliate companies of PJM EDCs that own generating resources.
- **PJM EDC Marketing 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, 2021, PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 55.2 percent (Table 5-8), down from 59.7 percent on June 1, 2020. The combined market share of LSEs not affiliated with any EDC and of non-PJM EDC affiliates was 44.8 percent, up from 40.3 percent on June 1, 2020. 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, 2021, 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 55.2 percent on June 1, 2021. 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 44.8 percent on June 1, 2021. 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.

Table 5-8 Capacity market load obligation served: June 1, 2020 and June 1, 2021

	1-Jun-20		1-Jun-21		Change	
	Obligation (MW)	Percent of total obligation	Obligation (MW)	Percent of total obligation	Obligation (MW)	Percent of total obligation
PJM EDCs and Affiliates	104,849.4	59.7%	96,306.4	55.2%	(8,543.1)	(4.5%)
LSEs not affiliated with any EDC + non EDC Affiliates	70,838.3	40.3%	78,114.1	44.8%	7,275.8	4.5%
Total	175,687.7	100.0%	174,420.4	100.0%	(1,267.3)	0.0%

Figure 5-3 Capacity market load obligation served: June 1, 2007 through June 1, 2021



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 six months prior to the delivery year.

The CTR issue implies a broader issue with capacity market clearing and settlements. The capacity market is cleared based on a three year ahead forecast of load and offers of capacity. Payments to capacity resources in the delivery year are based on the capacity market clearing prices and quantities. But payments by customers in the delivery year are not based on market clearing prices and quantities. Payments by customers in each zone are based on the ratio of zonal forecast peak load to the RTO forecast peak load used for the Third Incremental Auction, run six months prior to the delivery year when auctions follow the traditional schedule.⁶¹ 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

⁶¹ See "PJM Manual 18: PJM Capacity Market," §7.2.3 Final Zonal Unforced Capacity Obligations, Rev. 51 (October 20, 2021).

the clearing of the Base Residual Auction was 24,983.0 MW. The final ComEd Zone's capacity obligation for 2021/2022 Delivery Year after the Third Incremental Auction was 22,721.2 MW.

As with CTRs, the underlying reasons for not using the market clearing results 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 2022/2023 RPM Base Residual Auction, EMAAC had 4,946.8 MW of CTRs with a total value of \$3,737,529, COMED had 2,367.2 MW of CTRs with a total value of \$16,381,936, BGE had 4,745.1 MW of CTRs with a total value of \$53,188,332 and DEOK had 3,034.8 MW of CTRs with a total value of \$24,026,133.

MAAC had 270.1 MW of customer funded ICTRs with a total value of \$4,513,768, EMAAC had 40.0 MW of customer funded ICTRs with a total value of \$30,222, BGE had 65.7 MW of customer funded ICTRs with a total value of \$736,441, COMED had 1,376.0 MW of customer funded ICTRs with a total value of \$9,522,470 and DEOK had 155.0 MW of customer funded ICTRs with a total value of \$1,227,112.

MAAC had 128.0 MW of ICTRs due to Incremental Rights-Eligible Required Transmission Enhancements with a value of \$2,139,474, EMAAC had 948.0 MW with a value of \$716,261 and BGE had 306.0 MW with a value of \$3,430,000.

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.⁶² Figure 5-4 shows the shape of the VRR curve compared to a vertical demand curve at the reliability requirement for the 2022/2023 RPM Base Residual Auction.

In proposing the downward sloping portion of the VRR curve, PJM asserted that the sloping VRR curve recognizes the value of incremental capacity above the target reserve margin providing additional reliability benefit at a declining rate.⁶³

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

Effective for the 2018/2019 and subsequent delivery years, PJM revised the VRR curve.⁶⁴ PJM defines the reliability requirement as the capacity needed to satisfy the one event in ten years loss of load expectation (LOLE) for the RTO and capacity needed to satisfy the one event in 25 years loss of load expectation for the each LDA. The maximum price on the VRR curve is the greater of Gross CONE or 1.5 times Net CONE for all unforced capacity MW between 0 and 99 percent of

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

63 See 117 FERC ¶ 61,331 (2006).

64 "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>>.

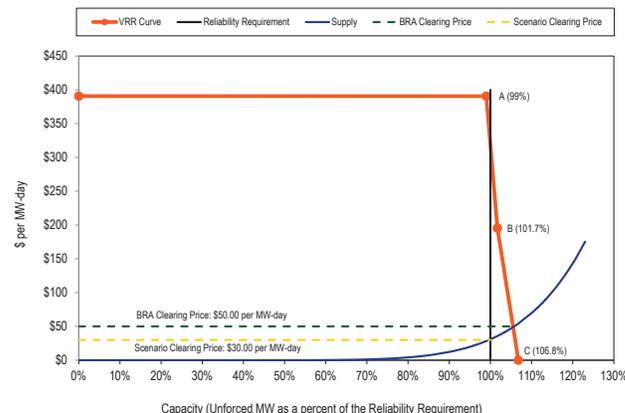
the reliability requirement. The first downward sloping segment is from 99 percent and 101.7 percent of the reliability requirement. The second downward sloping segment is from 101.7 percent and 106.8 percent of the reliability requirement (Figure 5-4).

The downward sloping shape of the demand curve, the VRR curve, had a significant impact on the outcome of the 2022/2023 BRA. As a result of the downward sloping VRR demand curve, more capacity cleared in the market than would have cleared with a vertical demand curve set equal to the reliability requirement.

Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2022/2023 RPM Base Residual Auction were \$3,916,990,303. If PJM had used a vertical demand curve set equal to the reliability requirement for 2022/2023 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2022/2023 RPM Base Residual Auction would have been \$2,659,527,128, a decrease of \$1,257,463,175, or 32.1 percent, compared to the actual results. From another perspective, clearing the auction using a downward sloping VRR curve resulted in a 47.3 percent increase in RPM revenues for the 2022/2023 RPM Base Residual Auction compared to what RPM revenues would have been with a vertical demand curve set equal to the reliability requirement.

The PJM definition of the VRR curve means the clearing price and cleared quantity will be higher, almost without exception, using the current VRR curve than using a vertical demand curve at the reliability requirement. As a result, payments for capacity will be higher. Figure 5-4 shows the RTO VRR curve and RTO reliability requirement for the 2022/2023 RPM BRA. The clearing price and cleared quantity would have been lower if a vertical VRR curve set at the reliability requirement had been used in place of the existing VRR curve. In the 2022/2023 BRA, the RTO clearing price would have decreased from \$50.00 per MW-day to \$30.00 per MW-day, and the clearing quantity would have decreased from 144,477.3 MW to 132,006.7 MW.

Figure 5-4 Shape of the VRR curve relative to the reliability requirement: 2022/2023 Delivery Year



Market Concentration

Auction Market Structure

As shown in Table 5-9, in the 2021/2022 RPM Third Incremental Auction and the 2022/2023 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.⁶⁵ Offer caps were applied to all sell offers for resources which were subject to mitigation when the capacity market seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.^{66 67 68}

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.

⁶⁵ 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.

⁶⁶ See OATT Attachment DD § 6.5.

⁶⁷ 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).

⁶⁸ 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 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.

Table 5-9 RSI results: 2019/2020 through 2022/2023 RPM Auctions⁶⁹

RPM Markets	$RSI_{1,105}$	RSI_3	Total Participants	Failed RSI_3 Participants
2019/2020 Base Residual Auction				
RTO	0.81	0.66	131	131
EMAAC	0.79	0.23	6	6
ComEd	0.74	0.12	6	6
BGE	0.00	0.00	1	1
2019/2020 First Incremental Auction				
RTO	0.63	0.50	53	53
EMAAC	0.00	0.00	5	5
2019/2020 Second Incremental Auction				
RTO	0.61	0.48	38	38
BGE	0.00	0.00	1	1
2019/2020 Third Incremental Auction				
RTO	0.70	0.59	72	72
2020/2021 Base Residual Auction				
RTO	0.81	0.69	119	119
MAAC	0.67	0.77	24	24
EMAAC	0.45	0.18	21	21
ComEd	0.47	0.20	14	14
DEOK	0.00	0.00	1	1
2020/2021 First Incremental Auction				
RTO	0.47	0.42	47	47
2020/2021 Second Incremental Auction				
RTO	0.40	0.56	34	34
2020/2021 Third Incremental Auction				
RTO	0.54	0.72	59	59
MAAC	0.25	0.18	14	14
2021/2022 Base Residual Auction				
RTO	0.80	0.68	122	122
EMAAC	0.71	0.22	14	14
PSEG	0.20	0.01	5	5
ATSI	0.01	0.00	2	2
ComEd	0.08	0.02	5	5
BGE	0.23	0.00	3	3
2021/2022 First Incremental Auction				
RTO	0.57	0.48	26	26
EMAAC	0.00	0.82	5	3
PSEG	0.00	0.00	1	1
PSEG North	0.00	0.00	2	2
BGE	0.00	0.00	1	1
2021/2022 Second Incremental Auction				
RTO	0.19	0.12	19	19
EMAAC	0.05	0.23	7	5
PSEG	0.00	0.00	2	2
BGE	0.00	0.00	0	0
2021/2022 Third Incremental Auction				
RTO	0.57	0.41	59	59
EMAAC	1.00	0.19	6	6
PSEG	0.00	0.00	1	1
BGE	0.00	-0.00	2	2
2022/2023 Base Residual Auction				
RTO	0.81	0.73	130	130
MAAC	0.69	0.37	25	25
EMAAC	1.25	0.64	7	7
ComEd	0.43	0.36	14	14
BGE	0.00	0.00	1	1
DEOK	0.00	0.00	1	1

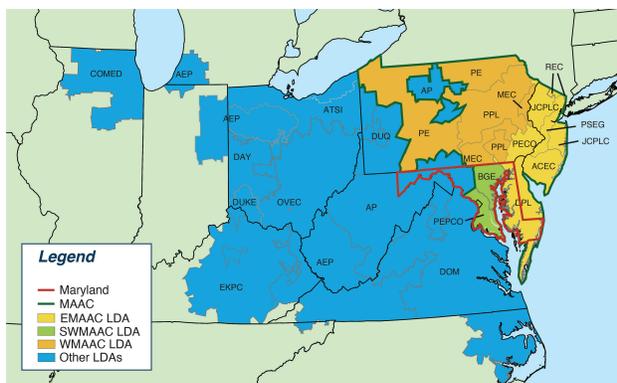
⁶⁹ The RSI shown is the lowest RSI in the market.

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.⁷⁰ 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.”⁷¹ 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 are 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, are established for each modeled LDA.⁷²

Locational Deliverability Areas are shown in Figure 5-5, Figure 5-6 and Figure 5-7.

Figure 5-5 Map of locational deliverability areas



⁷⁰ 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.

⁷¹ OATT Attachment DD § 5.10 (a) (ii).

⁷² 146 FERC ¶ 61,052 (2014).

Figure 5-6 Map of RPM EMAAC subzonal LDAs

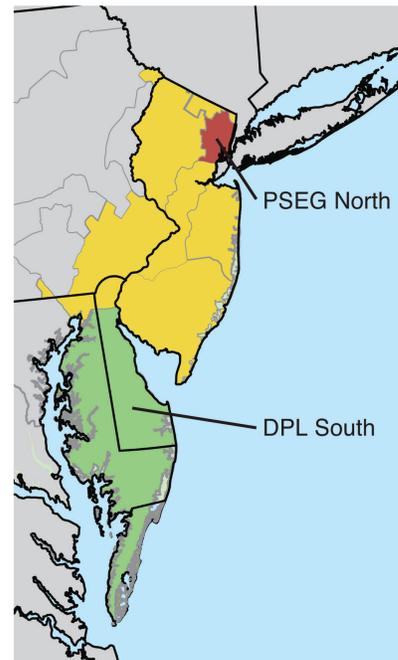
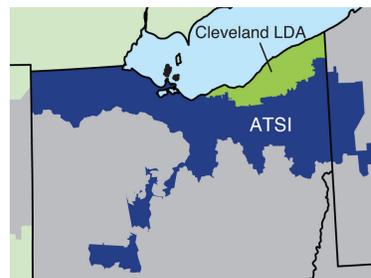


Figure 5-7 Map of RPM ATSI subzonal LDA



Imports and Exports

Units external to the metered boundaries of PJM can qualify as PJM capacity resources if they meet the requirements to be capacity resources. Generators on the PJM system that do not have a commitment to serve PJM loads in the given delivery year as a result of RPM auctions, FRR capacity plans, locational UCAP transactions, and/or are not designated as a replacement resource, are eligible to export their capacity from PJM.⁷³

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

⁷³ OATT Attachment DD § 5.6.6(b).

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 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.⁷⁴

Effective May 9, 2017, significantly improved pseudo tie requirements for external generation capacity resources were implemented.⁷⁵ 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.^{76 77 78} Firm transmission service must be acquired from all external transmission providers between the unit and border of PJM and generation deliverability into PJM must be demonstrated prior to the start of the delivery year. In order to demonstrate generation deliverability into PJM, external generators must obtain firm point to point transmission service on the PJM OASIS from the PJM border into the PJM transmission system or by obtaining network external designated transmission service. In the event that transmission upgrades are required to establish deliverability, those upgrades must be completed by the start of the delivery year. The following are also required: the external generating unit must be in the resource portfolio of a PJM member; twelve 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.⁷⁹

⁷⁴ External resources are not assigned to any of the five global LDAs or 22 zonal and subzonal LDAs. PJM's current practice is to model external resources in the rest of RTO. The practice is not currently documented by PJM. It was previously documented in "PJM Manual 18: PJM Capacity Market," § 2.3.4 Capacity Import Limits, Rev. 39 (December 21, 2017).

⁷⁵ 161 FERC ¶ 61,197 (2017).

⁷⁶ See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 9 Et 10.

⁷⁷ "PJM Manual 18: PJM Capacity Market," § 4.2.2 Existing Generation Capacity Resources – External, Rev. 51 (Oct. 20, 2021).

⁷⁸ "PJM Manual 18: PJM Capacity Market," § 4.6.4 Importing an External Generation Resource, Rev. 51 (Oct. 20, 2021).

⁷⁹ OATT Schedule 1 § 1.10.1A.

Planned External Generation Capacity Resources are eligible to be offered into an RPM Auction if they meet specific requirements.^{80 81} 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.⁸² 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.⁸³

As shown in Table 5-10, of the 1,558.0 MW of imports offered in the 2022/2023 RPM Base Residual Auction, 1,558.0 MW cleared. Of the cleared imports, 954.9 MW (61.3 percent) were from MISO.

Table 5-10 RPM imports: 2007/2008 through 2022/2023 RPM Base Residual Auctions

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

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

81 "PJM Manual 18: PJM Capacity Market," § 4.2.4 Planned Generation Capacity Resources – External, Rev. 51 (Oct. 20, 2021).

82 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).

83 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).

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.⁸⁴ If DR displaces new generation resources in BRAs, but then buys out of the position prior to the delivery year, this means potentially replacing new entry generation resources at the high end of the supply curve with other existing but uncleared capacity resources available in Incremental Auctions at reduced offer prices. This suppresses the price of capacity in the BRA compared to the competitive result because it permits the shifting of demand from the BRA to the Incremental Auctions, which is inconsistent with the must offer, must buy rules, and the requirement to be an actual, physical resource, governing the BRA. PJM's sell back of capacity in Incremental Auctions exacerbates the incentive for DR to buy out of its BRA positions in IAs.

There are two categories of demand side products included in the RPM market design for the 2022/2023 BRA:^{85 86}

- **Demand Resources (DR).** Interruptible load resource that is offered in an RPM Auction as capacity and receives the relevant LDA or RTO resource clearing price.
- **Energy Efficiency (EE) Resources.** Load resources that are offered in an RPM Auction as capacity and receive the relevant LDA or RTO resource clearing price. An EE Resource is a project designed to achieve a continuous (during peak periods) reduction in electric energy consumption during peak periods that is not reflected in the peak load forecast for the delivery year for which the EE is proposed, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention.⁸⁷ The peak period definition for the EE Resource type is

84 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).

85 Effective June 1, 2007, the PJM Active Load Management (ALM) program was replaced by the PJM Load Management (LM) program. Under ALM, providers had received a MW credit which offset their capacity obligation. With the introduction of LM, qualifying load management resources can be offered in RPM Auctions as capacity resources and receive the clearing price.

86 Interruptible load for reliability (ILR) is an interruptible load resource that is not offered into the RPM Auction, but receives the final zonal ILR price determined after the Second Incremental Auction. The ILR product was eliminated as of the 2012/2013 Delivery Year.

87 "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 6, Section L.

even more limited than Limited DR, including only the period from the hour ending 15:00 and the hour ending 18:00 from June through August, excluding weekends and federal holidays. The EE Resource type was eligible to be offered in RPM Auctions starting with the 2012/2013 Delivery Year and in Incremental Auctions in the 2011/2012 Delivery Year.⁸⁸

Effective with the 2020/2021 Delivery Year, the Capacity Performance product will include two possible season types, annual and summer.

- **Annual Capacity Performance Resources**

- **Annual Demand Resources.** A Demand Resource that is required to be available on any day during the Delivery Year for an unlimited number of interruptions. Annual DR is required to be capable of maintaining each interruption between the hours of 10:00 a.m. and 10:00 p.m. EPT for the months of June through October and the following May and between the hours of 6:00 a.m. and 9:00 p.m. EPT for the months of November through April unless there is a PJM approved maintenance outage during the October through April period.
- **Annual Energy Efficiency Resources.** A project designed to achieve a continuous (during summer and winter peak periods) reduction in electric energy consumption during peak periods that is not reflected in the peak load forecast for the delivery year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention. The peak period definition for the Annual Efficiency Resource type includes the period between the hour ending 15:00 EPT and the hour ending 18:00 EPT from June through August, and between the hour ending 8:00 EPT and the hour ending 9:00 EPT and between the hour ending 19:00 EPT and the hour ending 20:00 EPT from January 1 through February 28, excluding weekends and federal holidays.

- **Seasonal Capacity Performance Resources**

- **Summer-Period Demand Resources.** A Demand Resource that is 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. Summer Period DR is required to be capable of maintaining each interruption between the hours of 10:00 a.m. to 10:00 p.m. EPT.
- **Summer-Period Energy Efficiency Resources.** A project designed to achieve a continuous (during summer peak periods) reduction in electric energy consumption during peak periods that is not reflected in the peak load forecast for the delivery year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention. The peak period definition for the Summer-Period Efficiency Resource type includes the period from the hour ending 15:00 EPT and the hour ending 18:00 EPT from June through August, excluding weekends and federal holidays.

As shown in Table 5-11, Table 5-12, and Table 5-13, capacity in the RPM load management programs was 12,115.9 MW for June 1, 2021, as a result of cleared capacity for demand resources and energy efficiency resources in RPM auctions for the 2021/2022 Delivery Year (16,233.9 MW) less replacement capacity (4,118.0 MW).

⁸⁸ Letter Order in Docket No. ER10-366-000 (January 22, 2010).

Table 5-11 RPM load management statistics by LDA: June 1, 2018 to June 1, 2022^{89 90 91}

	UCAP (MW)															
	RTO	MAAC	EMAAC	SWMAAC	DPL		PSEG			ATSI						
					South	PSEG	North	Pepco	ATSI	Cleveland	ComEd	BGE	PPL	DAY	DEOK	
01-Jun-18	DR cleared	11,435.4	4,361.9	1,707.2	1,226.4	86.8	389.9	139.2	559.3	1,034.3	287.2	1,895.2	667.1	716.2		
	EE cleared	2,296.3	706.8	315.9	317.6	9.2	102.0	45.2	186.1	184.4	33.2	807.4	131.5	43.1		
	DR net replacements	(3,182.4)	(1,268.4)	(584.3)	(199.5)	(52.4)	(150.9)	(43.6)	(25.6)	(261.0)	(136.7)	(430.0)	(173.9)	(220.0)		
	EE net replacements	248.8	163.0	45.5	107.6	1.1	22.4	9.1	(8.9)	14.7	4.7	29.0	116.5	5.4		
	RPM load management	10,798.1	3,963.3	1,484.3	1,452.1	44.7	363.4	149.9	710.9	972.4	188.4	2,301.6	741.2	544.7		
01-Jun-19	DR cleared	10,703.1	3,878.9	1,659.2	817.0	91.3	381.2	176.5	554.6	1,047.0	333.9	1,759.9	262.4	741.4		
	EE cleared	2,528.5	821.4	395.3	301.7	7.8	134.5	52.8	170.0	204.8	41.7	792.9	131.7	72.7		
	DR net replacements	(2,138.8)	(1,004.2)	(468.8)	(129.0)	(40.9)	(141.5)	(86.6)	(74.8)	(130.3)	(123.1)	(143.0)	(54.2)	(208.9)		
	EE net replacements	(50.0)	(24.1)	4.7	3.3	(0.2)	2.7	9.1	2.2	3.4	0.0	0.0	1.1	(20.4)		
	RPM load management	11,042.8	3,672.0	1,590.4	993.0	58.0	376.9	151.8	652.0	1,124.9	252.5	2,409.8	341.0	584.8		
01-Jun-20	DR cleared	9,445.7	2,829.1	1,168.9	485.8	72.6	339.0	152.7	236.3	951.7	231.9	1,657.3	249.5	616.6	241.5	184.7
	EE cleared	3,569.5	1,288.8	700.3	394.5	28.8	246.1	111.3	196.2	356.0	72.9	852.0	198.3	111.4	79.5	105.6
	DR net replacements	(2,399.5)	(858.7)	(369.0)	(176.5)	(29.7)	(136.5)	(89.0)	(53.3)	(121.1)	(36.2)	(314.5)	(123.2)	(171.0)	(66.1)	(27.5)
	EE net replacements	(29.7)	(0.5)	(0.3)	5.9	0.0	(6.3)	12.0	(0.6)	(0.2)	0.0	(0.1)	6.5	(5.2)	0.0	(5.0)
	RPM load management	10,586.0	3,258.7	1,499.9	709.7	71.7	442.3	187.0	378.6	1,186.4	268.6	2,194.7	331.1	551.8	254.9	257.8
01-Jun-21	DR cleared	11,427.7	3,454.1	1,381.5	624.9	66.3	410.5	188.6	345.9	1,196.8	272.8	2,073.7	279.0	697.7	227.7	220.5
	EE cleared	4,806.2	1,810.5	979.1	501.1	42.0	353.1	136.0	275.9	420.5	95.7	982.7	225.2	186.7	111.0	135.5
	DR net replacements	(4,111.0)	(1,302.8)	(568.4)	(160.8)	(28.1)	(195.8)	(100.2)	(106.5)	(483.2)	(137.4)	(609.5)	(54.3)	(235.1)	(50.9)	(90.2)
	EE net replacements	(7.0)	0.0	0.0	(1.1)	0.1	0.0	34.9	(2.6)	80.0	7.0	10.6	1.5	(1.7)	8.0	(17.5)
	RPM load management	12,115.9	3,961.8	1,792.2	964.1	80.3	567.8	259.3	512.7	1,214.1	238.1	2,457.5	451.4	647.6	295.8	248.3
01-Jun-22	DR cleared	8,811.9	2,817.4	1,139.9	485.3	48.4	294.6	93.8	322.7	924.1	166.5	1,511.0	162.6	661.7	210.5	185.1
	EE cleared	4,810.6	1,974.4	1,090.8	463.7	49.6	384.4	182.6	263.8	417.0	41.8	723.9	199.9	242.1	91.8	145.9
	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
	EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	RPM load management	13,622.5	4,791.8	2,230.7	949.0	98.0	679.0	276.4	586.5	1,341.1	208.3	2,234.9	362.5	903.8	302.3	331.0

Table 5-12 RPM commitments, replacements, and registrations for demand resources: June 1, 2007 to June 1, 2022^{92 93 94}

	UCAP (MW)						Registered DR		
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM Commitment Shortage	RPM Commitments Less Commitment Shortage	ICAP (MW)	UCAP Conversion	
								Factor	UCAP (MW)
01-Jun-07	127.6	0.0	0.0	127.6	0.0	127.6	0.0	1.033	0.0
01-Jun-08	559.4	0.0	(40.0)	519.4	(58.4)	461.0	488.0	1.034	504.7
01-Jun-09	892.9	0.0	(474.7)	418.2	(14.3)	403.9	570.3	1.033	589.2
01-Jun-10	962.9	0.0	(516.3)	446.6	(7.7)	438.9	572.8	1.035	592.6
01-Jun-11	1,826.6	0.0	(1,052.4)	774.2	0.0	774.2	1,117.9	1.035	1,156.5
01-Jun-12	8,752.6	(11.7)	(2,253.6)	6,487.3	(34.9)	6,452.4	7,443.7	1.037	7,718.4
01-Jun-13	10,779.6	0.0	(3,314.4)	7,465.2	(30.5)	7,434.7	8,240.1	1.042	8,586.8
01-Jun-14	14,943.0	0.0	(6,731.8)	8,211.2	(219.4)	7,991.8	8,923.4	1.042	9,301.2
01-Jun-15	15,774.8	(321.1)	(4,829.7)	10,624.0	(61.8)	10,562.2	10,946.0	1.038	11,360.0
01-Jun-16	13,284.7	(19.4)	(4,800.7)	8,464.6	(455.4)	8,009.2	8,961.2	1.042	9,333.4
01-Jun-17	11,870.7	0.0	(3,870.8)	7,999.9	(30.3)	7,969.6	8,681.4	1.039	9,016.3
01-Jun-18	11,435.4	0.0	(3,182.4)	8,253.0	(1.0)	8,252.0	8,512.0	1.091	9,282.4
01-Jun-19	10,703.1	0.0	(2,138.8)	8,564.3	(0.4)	8,563.9	9,229.9	1.090	10,056.0
01-Jun-20	9,445.7	0.0	(2,399.5)	7,046.2	(0.1)	7,046.1	7,867.6	1.088	8,561.5
01-Jun-21	11,427.7	0.0	(4,111.0)	7,316.7	0.0	7,316.7	7,754.2	1.087	8,429.6
01-Jun-22	8,811.9	0.0	0.0	8,811.9	0.0	8,811.9	0.0	1.087	0.0

89 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.

90 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.

91 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.

92 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.

93 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.

94 See OATT Attachment DD § 5.14E. The reported DR adjustments to cleared MW for the 2016/2017, 2017/2018, and 2018/2019 Delivery Years include reductions in the level of committed MW due to the Demand Response Legacy Direct Load Control Transition Provision.

Table 5-13 RPM commitments and replacements for energy efficiency resources: June 1, 2007 to June 1, 2022^{95 96}

	UCAP (MW)					
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM Commitment Shortage	RPM Commitments Less Commitment Shortage
01-Jun-07	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-08	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-09	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-10	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-11	76.4	0.0	0.2	76.6	0.0	76.6
01-Jun-12	666.1	0.0	(34.9)	631.2	(5.1)	626.1
01-Jun-13	904.2	0.0	120.6	1,024.8	(13.5)	1,011.3
01-Jun-14	1,077.7	0.0	204.7	1,282.4	(0.2)	1,282.2
01-Jun-15	1,189.6	0.0	335.9	1,525.5	(0.9)	1,524.6
01-Jun-16	1,723.2	0.0	61.1	1,784.3	(0.5)	1,783.8
01-Jun-17	1,922.3	0.0	195.6	2,117.9	(7.4)	2,110.5
01-Jun-18	2,296.3	0.0	248.8	2,545.1	0.0	2,545.1
01-Jun-19	2,528.5	0.0	(50.0)	2,478.5	0.0	2,478.5
01-Jun-20	3,569.5	0.0	(29.7)	3,539.8	(0.1)	3,539.7
01-Jun-21	4,806.2	0.0	(7.0)	4,799.2	0.0	4,799.2
01-Jun-22	4,810.6	0.0	0.0	4,810.6	0.0	4,810.6

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. 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 were used in the 2022/2023 BRA. 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.⁹⁷ The MMU opposed the

new ELCC rules because they fail to incorporate the marginal ELCC value of resources, rely on significant counterfactual behavioral assumptions, do not apply to all resource types, and use invented (putative) data as key inputs, among other issues, but does not oppose the ELCC approach in concept and when done correctly.⁹⁸ PJM's flawed ELCC approach will create new issues for the PJM Capacity Markets unless addressed promptly. If done correctly, including the application of ELCC to all resources, ELCC could be an advance over the current approach to defining the MW of capacity provided by all resource types, including intermittent resources.

PJM's flawed ELCC approach, based on static average rather than dynamic, market defined marginal values and basing the results on incorrect assumptions about the dispatch of some resource types, will create new issues for the PJM Capacity Markets unless addressed in the near future. If done correctly, ELCC would be an advance over the current approach to discounting the reliability contribution of intermittent resources, but only if done correctly and only if all the required assumptions are made explicit and decided explicitly.

Derating factors and ELCC values are used in capacity auctions to convert the nameplate capacity of intermittent and storage resources into MW of capacity equivalent to resources that can produce for any of the 8,760 hours in a year. Both the capacity derating factors applied to intermittent nameplate capacity in the 2022/2023 BRA and the ELCC calculations to be used for future capacity auctions are based on the assumption that the intermittent resources provide reliable output in excess of their CIRs. But that output is not deliverable when needed for reliability because it is in excess of the

⁹⁵ Pursuant to the OA § 15.1.6(c), PJM Settlement shall close out and liquidate all forward positions of PJM members that are declared in default. The replacement transactions reported for the 2014/2015 Delivery Year included transactions associated with RTP Controls, Inc., which was declared in collateral default on March 9, 2012.

⁹⁶ Effective with the 2019/2020 Delivery Year, available capacity from an EE Resource can be used to replace only EE Resource commitments. This rule change and related EE addback rule changes were endorsed at the December 17, 2015, meeting of the PJM Markets and Reliability Committee.

⁹⁷ See 176 FERC ¶ 61,056. There are multiple ways to apply the ELCC method. There is not a single ELCC method.

⁹⁸ Comments and Motions of the Independent Market Monitor for PJM, Docket No. ER21-278 and EL19-100 (November 20, 2020). Answer and Motion for Leave to Answer and Alternative Motion for Consolidation of the Independent Market Monitor for PJM, Docket No. ER21-278 (December 10, 2020). Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER21-278 (December 18, 2020). Comments and Motions of the Independent Market Monitor for PJM, ER21-278-001 (March 22, 2021). Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER21-278 (April 28, 2021).

defined deliverability rights (CIRs) and therefore should not be included in the definition of intermittent capacity.

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.

Market Conduct

Offer Caps

Market power mitigation measures were applied to capacity resources such that the sell offer was set equal to the defined offer cap when the capacity market seller failed the market structure test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would have increased the market clearing price.^{99 100 101} 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, 2021.¹⁰² 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.¹⁰³ As a result, the tariff defines avoidable costs as the costs that a generation owner would not incur if the generating unit did not offer for one year. Although the term mothball is used in the tariff to modify the term ACR, the term mothball is not defined in the tariff. Mothball is an informal term better understood as a metaphor for the cost to operate for one year. Avoidable costs are the costs to operate the unit for one year, regardless of whether the unit plans to retire. Although the tariff includes different mothball and retirement values, the distinction is based on a misunderstanding of the meaning of avoidable costs and should be eliminated. PJM never explained exactly how it calculated mothball and retirement avoidable cost levels. The MMU recommends that major maintenance costs be included in the definition of avoidable costs and removed from energy offers because such costs are avoidable costs and not short run marginal costs.¹⁰⁴ 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 and expected bonus performance payments/nonperformance charges.¹⁰⁵ 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

99 See OATT Attachment DD § 6.5.

100 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).

101 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).

102 176 FERC ¶ 61,137 (September 2, 2021).

103 OATT Attachment DD § 6.8 (b).

104 *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).

105 For details on the competitive offer of a capacity performance resource, 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).

components of avoidable costs are defined in the PJM tariff.¹⁰⁶

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).¹⁰⁷ AFAE is available for Capacity Performance Resources. AFAE is defined to include expenses related to fuel availability and delivery. CPQR is available for Capacity Performance Resources and, for the 2018/2019 and 2019/2020 Delivery Years, Base Capacity Resources. CPQR is defined to be the quantifiable and reasonably supported cost of mitigating the risks of nonperformance associated with submission of an offer.

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

Competitive Offers

The competitive offer of a Capacity Performance resource is based 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) including gross ACR, forward looking net revenues and the impact of the resource's performance during performance assessment intervals (A) in the delivery year on its risk and the cost to mitigate that risk.¹⁰⁸

The competitive offer of a Capacity Performance resource is also 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 (H) where the resource is located; the level of performance required to meet its capacity obligation during those performance assessment intervals,

measured as the average Balancing Ratio (B); and the level of the bonus performance payment rate (CPBR) compared to the nonperformance charge rate (PPR). The total capacity revenues earned by a resource are the sum of revenues earned in the forward capacity auctions and additional bonus revenues earned (or penalties paid) during the delivery year, which are a function of unit performance during PAI (A). The level of the bonus performance payment rate depends on the level of underperforming MW net of the underperforming MW excused by PJM during performance assessment intervals for reasons defined in the PJM OATT.¹⁰⁹

Under the original Capacity Performance design, the competitive offer of a resource was the larger of the opportunity cost of taking on a CP obligation (the default offer cap), or a unit specific offer cap based on its net ACR. But the default offer cap defined in the PJM tariff was based on strong assumptions that are not correct. The default offer cap was based on the opportunity cost of taking on a CP obligation when the resource could have earned enough revenues by staying as an energy only resource and earned enough bonus revenues to cover its avoidable costs. If the resource's net avoidable costs are higher than the bonuses it expects to earn during performance assessment intervals in the delivery year, its competitive offer is its net ACR adjusted with any bonuses or nonperformance charges it may incur during the delivery year.

The basic assumptions of the Capacity Performance design are not correct and as a result the competitive offer is not Net CONE times B. Two of the core assumptions are that it is reasonable to expect 360 PAI and that it is reasonable to expect that the bonus performance payment rate (bonus rate or CPBR) is equal to the nonperformance charge rate (penalty rate or PPR). There have been effectively zero true PAI since the introduction of the capacity performance model. This does not mean that there will never be PAI or that there will never be 360 PAI. It does mean that it is not reasonable to include the assumption of 360 PAI in establishing the definition of a competitive offer in the capacity market. It does mean that there is no accurate way to calculate expected PAI for the market and that a design based on that calculation will not be based on market fundamentals. The bonus rate has been

¹⁰⁶ OATT Attachment DD § 6.8(a).

¹⁰⁷ 151 FERC ¶ 61,208.

¹⁰⁸ The model is only applicable to generation resources and storage resources that have an annual obligation to perform with very limited specific excuses as defined in the PJM OATT.

¹⁰⁹ OATT Attachment DD § 10A (d).

significantly lower than the penalty rate and there is no reason to expect that to change. As a result, it is not reasonable to include the assumption that CPBR equals PPR in defining a competitive offer in the capacity market. PJM's interpretation of the rules has led to the ability of nonperforming or underperforming resources to avoid penalty payments and to a corresponding reduction in bonus payments. It is not consistent with actual capacity market rules to include the assumption that a generation unit is forgoing energy only status when it decides on a capacity market offer. The PJM Capacity Market has a must offer requirement for a reason; it is required in order to prevent the exercise of market power, particularly given the must buy obligation of load. If a capacity market seller wants to convert to energy only status, the owner must give up its CIRs. Such CIRs could be expensive and difficult to reacquire if the capacity market seller decided to reenter the capacity market.

The Net CONE times B offer caps are equivalent to assuming the worst case outcome as defined by the number of PAI and unit performance and permitting generation owners to use that worst case to define offers. It is more accurate and consistent with market logic to reflect the cost of mitigating the risk of making offers, in the presence of the risk of capacity market penalties, through the CPQR component of the ACR. The CPQR component is the cost of mitigating the risk faced by the generator rather than the full cost of the worst case scenario. Use of the CPQR component also permits generation owners to include their own views of the key market parameters in the calculation of the cost to mitigate risk, within a reasonable range, and subject to market power review.

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

The clearing prices for CP Resources were less than Net CONE times B for every zone. Of the 22 identified zones, the clearing price was less than 50 percent of Net CONE

times B in 14 zones and less than 60 percent in 20 zones. The clearing price in BGE Zone was 68.4 of Net CONE times B and the clearing price in Penelec Zone, where Net CONE was lower than other zones, was 78.4 of Net CONE times B. Overall, the average clearing price was 43.6 percent of the average Net CONE times B.¹¹⁰

2021/2022 RPM Third Incremental Auction

As shown in Table 5-14, 481 generation resources submitted Capacity Performance offers in the 2021/2022 RPM Third Incremental Auction. Unit specific offer caps were calculated for zero generation resources (0.0 percent). Of the 481 generation resources, 415 generation resources had the Net CONE times B offer cap (86.3 percent), 28 generation resources elected the offer cap option of 1.1 times the BRA clearing price (5.8 percent), 11 Planned Generation Capacity Resources had uncapped offers (2.3 percent), and the remaining 27 generation resources were price takers (5.6 percent). Market power mitigation was applied to the Capacity Performance sell offers of zero generation resources, including 0.0 MW.

2022/2023 RPM Base Residual Auction

As shown in Table 5-14, 1,083 generation resources submitted Capacity Performance offers in the 2022/2023 RPM Base Residual Auction. Unit specific offer caps were not calculated for any generation resources (0.0 percent). Of the 1,083 generation resources, 872 generation resources had the Net CONE times B offer cap (80.5 percent), 35 Planned Generation Capacity Resources had uncapped offers (3.2 percent), 40 generation resources had uncapped planned uprates plus Net CONE times B offer cap for the existing portion of the units (3.7 percent), four generation resources had uncapped planned uprates and were price takers for the existing portion of the unit (0.4 percent), and the remaining 132 generation resources were price takers (12.2 percent). Market power mitigation was not applied to any Capacity Performance sell offers.

¹¹⁰ See "Analysis of the 2022/2023 RPM Base Residual Auction," at 27, Table 3 (February 22, 2022) <http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20222023_RPM_BRA_20220222.pdf>

Table 5-14 ACR statistics: RPM auctions conducted in 2021

Offer Cap/Mitigation Type	2021/2022 Third Incremental Auction		2022/2023 Base Residual Auction	
	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	NA	NA	NA	NA
Unit specific ACR (APIR)	0	0.0%	0	0.0%
Unit specific ACR (APIR and CPQR)	0	0.0%	0	0.0%
Unit specific ACR (non-APIR)	0	0.0%	0	0.0%
Unit specific ACR (non-APIR and CPQR)	0	0.0%	0	0.0%
Opportunity cost input	0	0.0%	0	0.0%
Default ACR and opportunity cost	NA	NA	NA	NA
Net CONE times B	415	86.3%	872	80.5%
Offer cap of 1.1 times BRA clearing price elected	28	5.8%	NA	NA
Uncapped planned uprate and default ACR	NA	NA	NA	NA
Uncapped planned uprate and opportunity cost	0	0.0%	0	0.0%
Uncapped planned uprate and Net CONE times B	0	0.0%	40	3.7%
Uncapped planned uprate and price taker	0	0.0%	4	0.4%
Uncapped planned uprate and 1.1 times BRA clearing price elected	0	0.0%	NA	NA
Uncapped planned generation resources	11	2.3%	35	3.2%
Existing generation resources as price takers	27	5.6%	132	12.2%
Total Generation Capacity Resources offered	481	100.0%	1,083	100.0%

MOPR

By order issued December 19, 2019, the RPM Minimum Offer Price Rule (MOPR) was modified.¹¹¹ 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.¹¹² The MMU testified at the Technical Conference and provided comments and responses to the Commission's questions following the conference.¹¹³

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

¹¹² Technical Conference regarding Resource Adequacy in the Evolving Electricity Sector, Docket No. AD21-10 (March 23, 2021).

¹¹³ *Modernizing Electricity Market Design*, Comments of the Independent Market Monitor for PJM, Docket No. AD21-10 (April 26, 2021).

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.¹¹⁴ The revised MOPR in OATT Attachment DD § 5.14(h-2) is effective for RPM auctions for the 2023/2024 and subsequent delivery years. Under the revised MOPR, a generation resource would be subject to an

offer floor if the capacity is deemed to meet the definition of Conditioned State Support or if the capacity market seller plans to use the resource to exercise Buyer-Side Market Power as the term is defined in the tariff through either self certification or a fact specific review initiated by the MMU or PJM. Whether a state program or policy qualifies for Conditioned State Support would be the result of a Commission determination.

The MMU's filing in response to PJM's proposal was clear. The PJM markets would be better off, more competitive, and more efficient with no MOPR than with PJM's proposed approach. PJM's proposal would effectively eliminate the MOPR while creating a confusing and inefficient administrative process that effectively makes it both unnecessary and impossible to prove buyer side market power as PJM has defined it.¹¹⁵

The Commission approved PJM's proposed revisions to the PJM market rules to implement a forward looking EAS offset to include forward looking energy and ancillary services revenues rather than historical.¹¹⁶ The change in the offset affected MOPR floor prices and the results of unit specific reviews under MOPR in the 2022/2023 BRA.

¹¹⁴ *PJM Interconnection, LLC*, Notice of Filing Taking Effect by Operation of Law, Docket No. ER21-2582 (September 29, 2021).

¹¹⁵ 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).

¹¹⁶ 173 FERC ¶ 61,134 (2020).

The Commission approved PJM's proposed revisions to the PJM market rules to implement a forward looking EAS offset to include forward looking energy and ancillary services revenues rather than historical.¹¹⁷ The MMU has recommended such an approach. The change in the offset affected MOPR floor prices and the results of unit specific reviews under MOPR in the 2022/2023 BRA. This decision was reversed in the Commission's order related to the ORDC matter.¹¹⁸

Issues addressed during the MOPR unit specific review process in 2021 for the 2022/2023 BRA included documentation of asset life greater than 20 years, degradation of resource performance, operating and maintenance expenses, required capital expenditures, tax assumptions, documentation of forward net revenues, and the use of retail savings as a source of net revenue offset to EE gross CONE. The MMU did not agree with PJM's judgments about parameters and calculations of MOPR floors in a significant number of cases (Table 5-15).

MOPR Statistics

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

As shown in Table 5-15, of the 838.5 ICAP MW of MOPR Unit-Specific Exception requests for the 2021/2022 RPM Third Incremental Auction, requests for 838.5 MW were granted.

As shown in Table 5-15, of the 13,149.2 ICAP MW of MOPR Unit-Specific Exception and Resource-Specific Exception requests for the 2022/2023 RPM Base Residual Auction, the MMU agreed with requests for 6,794.7 MW.

Table 5-15 MOPR statistics: RPM auctions conducted in 2021¹¹⁹

MOPR Type	Calculation Type	Number of Requests	ICAP (MW)			UCAP (MW)	
			Requested	MMU Agreed	Offered	Offered	Cleared
2021/2022 Third Incremental Auction	Capacity Resources with No State Subsidy	77	838.5	838.5	248.2	246.5	103.9
	Capacity Resources with No State Subsidy	NA	NA	NA	82.1	81.4	0.0
	Total	77	838.5	838.5	330.3	327.9	103.9
2022/2023 Base Residual Auction	Capacity Resources with No State Subsidy	148	8,849.0	4,882.7	1,720.0	1,702.4	490.3
	Capacity Resources with State Subsidy - Cleared	2	2,134.0	1,240.0	2,134.0	2,126.1	2,126.1
	Capacity Resources with State Subsidy - New	109	2,166.2	672.0	1,207.1	1,248.5	1,104.4
	Capacity Resources with No State Subsidy	NA	NA	NA	116.7	98.9	0.0
	Capacity Resources with State Subsidy - Cleared	NA	NA	NA	6,590.9	6,332.9	4,954.7
	Capacity Resources with State Subsidy - New	NA	NA	NA	459.8	493.0	153.1
	Total	259	13,149.2	6,794.7	12,228.5	12,001.7	8,828.6

Replacement Capacity¹²⁰

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.

¹¹⁷ 173 FERC ¶ 61,134 (2020).

¹¹⁸ 177 FERC ¶ 61,209 (2021).

¹¹⁹ There were additional MOPR Screened Generation Resources for which no exceptions or exemptions were requested and to which the MOPR floor was applied. Some numbers are not reported as a result of PJM confidentiality rules.

¹²⁰ 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).

Table 5-16 shows the committed and replacement capacity for all capacity resources for June 1 of each year from 2007 through 2022. The 2022 numbers are not final.

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

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

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

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

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

The definition of demand side resources in PJM capacity markets is flawed in a variety of ways. The current demand side definition should be replaced with a definition that includes demand on the demand side of the market. There are ways to ensure and enhance the vibrancy of demand side without negatively affecting markets for generation. There are other price formation issues in the capacity market that should also be examined and addressed.¹²¹

Table 5-16 RPM commitments and replacements for all Capacity Resources: June 1, 2007 to June 1, 2022

	UCAP (MW)				RPM	RPM Commitments
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	Commitment Shortage	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	144,477.3	0.0	0.0	144,477.3	0.0	144,477.3

¹²¹ See Monitoring Analytics, LLC, "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).

Market Performance

Figure 5-8 shows cleared MW weighted average capacity market prices on a delivery year basis including base and incremental auctions for each delivery year, and the weighted average clearing prices by LDA in each Base Residual Auction for the entire history of the PJM capacity markets.

Table 5-17 shows RPM clearing prices for all RPM auctions held through 2021, and Table 5-18 shows the RPM cleared MW for all RPM auctions held through 2021.

Figure 5-9 shows the RPM cleared MW weighted average prices for each LDA from the 2018/2019 Delivery Year to the current delivery year, and all results for auctions for future delivery years that have been held through 2021. A summary of these weighted average prices is given in Table 5-19.

Table 5-20 shows RPM revenue by delivery year for all RPM auctions held through 2021 based on the unforced MW cleared and the resource clearing prices. In the 2019/2020 Delivery Year RPM revenue was \$7.1 billion. In the 2020/2021 Delivery Year, RPM revenue was \$7.0 billion.

Table 5-21 shows RPM revenue by calendar year for all RPM auctions held through 2021. In 2019, RPM revenue was \$8.7 billion. In 2020, RPM revenue was \$7.1 billion.

Table 5-22 shows the RPM annual charges to load. For the 2019/2020 Delivery Year, RPM annual charges to load were \$7.0 billion. For the 2020/2021 Delivery Year, annual charges to load are \$7.0 billion.

Table 5-17 Capacity market clearing prices: 2019/2020 through 2022/2023 RPM Auctions¹²²

	Product Type	RPM Clearing Price (\$ per MW-day)													
		RTO	MAAC	APS	PPL	EMAAC	SWMAAC	DPL		PSEG					
								South	PSEG	North	PEPCO	ATSI	COMED	BGE	DUKE
2019/2020 BRA	Base Capacity	\$80.00	\$80.00	\$80.00	\$80.00	\$99.77	\$80.00	\$99.77	\$99.77	\$99.77	\$80.00	\$80.00	\$182.77	\$80.30	\$80.00
2019/2020 BRA	Base Capacity DR/EE	\$80.00	\$80.00	\$80.00	\$80.00	\$99.77	\$80.00	\$99.77	\$99.77	\$99.77	\$0.01	\$80.00	\$182.77	\$80.30	\$80.00
2019/2020 BRA	Capacity Performance	\$100.00	\$100.00	\$100.00	\$100.00	\$119.77	\$100.00	\$119.77	\$119.77	\$119.77	\$100.00	\$100.00	\$202.77	\$100.30	\$100.00
2019/2020 First Incremental Auction	Base Capacity	\$15.00	\$15.00	\$15.00	\$15.00	\$22.22	\$15.00	\$22.22	\$22.22	\$22.22	\$15.00	\$15.00	\$15.00	\$15.00	\$15.00
2019/2020 First Incremental Auction	Base Capacity DR/EE	\$15.00	\$15.00	\$15.00	\$15.00	\$22.22	\$15.00	\$22.22	\$22.22	\$22.22	\$15.00	\$15.00	\$15.00	\$15.00	\$15.00
2019/2020 First Incremental Auction	Capacity Performance	\$51.33	\$51.33	\$51.33	\$51.33	\$58.55	\$51.33	\$58.55	\$58.55	\$58.55	\$51.33	\$51.33	\$51.33	\$51.33	\$51.33
2019/2020 Second Incremental Auction	Base Capacity	\$10.01	\$10.01	\$10.01	\$10.01	\$10.01	\$10.01	\$10.01	\$10.01	\$10.01	\$10.01	\$10.01	\$10.01	\$10.01	\$10.01
2019/2020 Second Incremental Auction	Base Capacity DR/EE	\$10.01	\$10.01	\$10.01	\$10.01	\$10.01	\$10.01	\$10.01	\$10.01	\$10.01	\$10.01	\$10.01	\$10.01	\$10.01	\$10.01
2019/2020 Second Incremental Auction	Capacity Performance	\$32.87	\$32.87	\$32.87	\$32.87	\$32.87	\$32.87	\$32.87	\$32.87	\$32.87	\$32.87	\$32.87	\$32.87	\$32.87	\$55.00
2019/2020 Third Incremental Auction	Base Capacity	\$21.35	\$21.35	\$21.35	\$21.35	\$21.35	\$21.35	\$21.35	\$21.35	\$21.35	\$21.35	\$21.35	\$21.35	\$21.35	\$21.35
2019/2020 Third Incremental Auction	Base Capacity DR/EE	\$21.35	\$21.35	\$21.35	\$21.35	\$21.35	\$21.35	\$21.35	\$21.35	\$21.35	\$21.35	\$21.35	\$21.35	\$21.35	\$21.35
2019/2020 Third Incremental Auction	Capacity Performance	\$28.35	\$28.35	\$28.35	\$28.35	\$28.35	\$28.35	\$28.35	\$28.35	\$28.35	\$28.35	\$28.35	\$28.35	\$28.35	\$28.35
2020/2021 BRA	Capacity Performance	\$76.53	\$86.04	\$76.53	\$86.04	\$187.87	\$86.04	\$187.87	\$187.87	\$187.87	\$86.04	\$76.53	\$188.12	\$86.04	\$76.53
2020/2021 First Incremental Auction	Capacity Performance	\$42.90	\$42.90	\$42.90	\$42.90	\$42.90	\$42.90	\$42.90	\$42.90	\$42.90	\$42.90	\$42.90	\$42.90	\$42.90	\$42.90
2020/2021 Second Incremental Auction	Capacity Performance	\$20.25	\$20.25	\$20.25	\$20.25	\$20.25	\$20.25	\$20.25	\$20.25	\$20.25	\$20.25	\$20.25	\$20.25	\$20.25	\$20.25
2020/2021 Third Incremental Auction	Capacity Performance	\$10.00	\$15.25	\$10.00	\$15.25	\$15.25	\$15.25	\$15.25	\$15.25	\$15.25	\$15.25	\$10.00	\$10.00	\$15.25	\$10.00
2021/2022 BRA	Capacity Performance	\$140.00	\$140.00	\$140.00	\$140.00	\$165.73	\$140.00	\$165.73	\$204.29	\$204.29	\$140.00	\$171.33	\$195.55	\$200.30	\$140.00
2021/2022 First Incremental Auction	Capacity Performance	\$23.00	\$23.00	\$23.00	\$23.00	\$25.00	\$23.00	\$25.00	\$25.00	\$45.00	\$219.00	\$23.00	\$23.00	\$23.00	\$60.00
2021/2022 Second Incremental Auction	Capacity Performance	\$10.26	\$10.26	\$10.26	\$10.26	\$15.37	\$10.26	\$15.37	\$125.00	\$125.00	\$10.26	\$10.26	\$10.26	\$70.00	\$10.26
2021/2022 Third Incremental Auction	Capacity Performance	\$20.55	\$20.55	\$20.55	\$20.55	\$26.36	\$20.55	\$26.36	\$31.00	\$31.00	\$20.55	\$20.55	\$20.55	\$39.00	\$20.55
2022/2023 BRA	Capacity Performance	\$50.00	\$95.79	\$50.00	\$95.79	\$97.86	\$95.79	\$97.86	\$97.86	\$97.86	\$95.79	\$50.00	\$68.96	\$126.50	\$71.69

¹²² See the 2019 State of the Market Report for PJM, Volume 2, Section 5: Capacity Market

Table 5-18 Capacity market cleared MW: 2019/2020 through 2022/2023 RPM Auctions¹²³

Delivery Year	Auction	UCAP (MW)													
		RTO	MAAC	APS	PPL	EMAAC	DPL South	PSEG North	PEPCO	ATSI	COMED	BGE	DUKE	TOTAL	
2019/2020	BASE	57,090.2	9,996.2	9,066.6	12,754.9	20,382.4	1,598.5	5,583.1	3,228.9	6,971.7	10,291.1	22,971.4	4,422.9	2,971.6	167,329.5
2019/2020	FIRST	774.9	249.4	39.3	157.7	78.7	11.7	10.6	28.8	43.6	147.5	711.4	31.9	9.6	2,295.1
2019/2020	SECOND	435.6	160.4	30.1	146.2	210.1	21.2	38.1	44.8	41.9	263.6	105.8	107.5	7.3	1,612.6
2019/2020	THIRD	1,531.9	440.9	429.4	1,216.6	265.7	2.4	180.4	23.2	83.6	454.2	867.4	255.2	76.1	5,827.0
2020/2021	BASE	53,574.6	11,413.2	8,990.6	14,398.2	19,978.5	1,647.2	5,041.2	2,975.4	6,410.0	9,925.9	23,960.3	4,021.1	2,437.8	164,773.9
2020/2021	FIRST	1,245.3	331.0	144.2	83.4	76.2	38.9	105.8	32.0	97.8	666.9	644.4	38.7	20.3	3,524.8
2020/2021	SECOND	415.7	206.9	53.0	30.7	302.9	28.4	29.5	48.8	35.4	366.2	194.6	160.3	31.5	1,903.8
2020/2021	THIRD	961.2	569.7	118.7	89.0	194.1	33.1	423.0	137.0	93.1	554.3	127.7	39.8	145.4	3,486.0
2021/2022	BASE	52,896.5	12,565.1	10,136.1	15,368.6	19,857.3	1,673.8	4,667.2	3,134.1	6,546.1	8,010.5	22,358.1	3,667.8	2,746.1	163,627.3
2021/2022	FIRST	194.1	200.4	45.9	27.2	119.0	15.3	18.3	79.1	207.9	739.3	360.4	48.7	87.6	2,143.2
2021/2022	SECOND	1,242.5	335.8	30.3	55.4	129.9	39.3	97.0	98.1	75.7	1,216.8	205.9	115.5	65.3	3,707.5
2021/2022	THIRD	1,638.4	168.7	231.6	127.8	911.0	18.3	227.7	244.8	67.2	942.7	221.7	275.9	159.2	5,235.0
2022/2023	BASE	37,732.2	12,804.7	10,147.4	14,118.7	23,658.8	1,305.3	1,914.3	2,531.1	3,621.8	10,550.7	19,223.7	4,750.9	2,117.7	144,477.3

Table 5-19 Weighted average clearing prices by zone: 2019/2020 through 2022/2023

LDA	Weighted Average Clearing Price (\$ per MW-day)			
	2019/2020	2020/2021	2021/2022	2022/2023
RTO				
AEP	\$93.63	\$74.42	\$133.84	\$50.00
APS	\$93.63	\$74.42	\$133.84	\$50.00
ATSI	\$92.97	\$69.75	\$142.59	\$50.00
Cleveland	\$89.17	\$68.93	\$90.81	\$50.00
COMED	\$188.90	\$182.15	\$189.54	\$69.02
DAY	\$93.63	\$72.42	\$132.69	\$50.00
DUKE	\$93.63	\$121.24	\$127.66	\$71.66
DUQ	\$93.63	\$74.42	\$133.84	\$50.00
DOM	\$93.63	\$74.42	\$133.84	\$50.00
EKPC	\$93.63	\$74.42	\$133.84	\$50.00
MAAC				
EMAAC				
ACEC	\$112.48	\$182.04	\$158.72	\$97.79
DPL	\$112.48	\$182.04	\$158.72	\$97.79
DPL South	\$115.95	\$178.65	\$159.65	\$97.86
JCPLC	\$112.48	\$182.04	\$158.72	\$97.79
PECO	\$112.48	\$182.04	\$158.72	\$97.79
PSEG	\$110.56	\$165.74	\$184.82	\$97.77
PSEG North	\$116.03	\$176.45	\$190.48	\$97.82
REC	\$112.48	\$182.04	\$158.72	\$97.79
SWMAAC				
BGE	\$88.20	\$80.71	\$174.43	\$126.49
PEPCO	\$90.59	\$84.24	\$133.37	\$95.19
WMAAC				
MEC	\$93.81	\$81.85	\$134.56	\$95.79
PE	\$93.81	\$81.85	\$134.56	\$95.79
PPL	\$88.53	\$85.07	\$138.51	\$95.77

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

Table 5-20 RPM revenue by delivery year: 2007/2008 through 2022/2023¹²⁴

Delivery Year	Weighted Average RPM Price (\$ per MW-day)	Weighted Average Cleared UCAP (MW)	Days	RPM Revenue
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	\$74.28	144,477.3	365	\$3,916,953,841

Table 5-21 RPM revenue by calendar year: 2007 through 2023¹²⁵

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	\$104.50	156,985.8	365	\$6,183,448,991
2023	\$74.28	59,770.1	151	\$1,620,438,438

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

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

Figure 5-8 History of capacity prices: 1999/2000 through 2022/2023¹²⁶

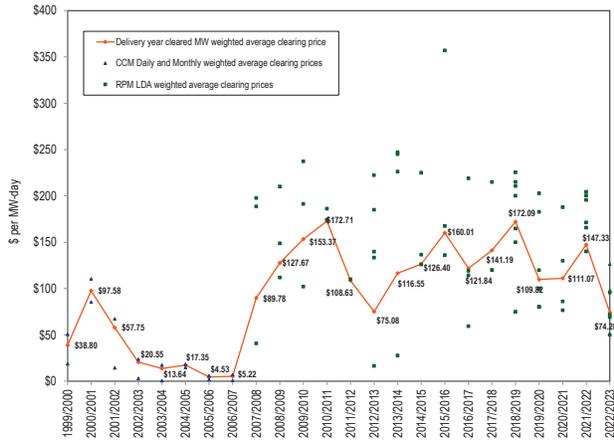
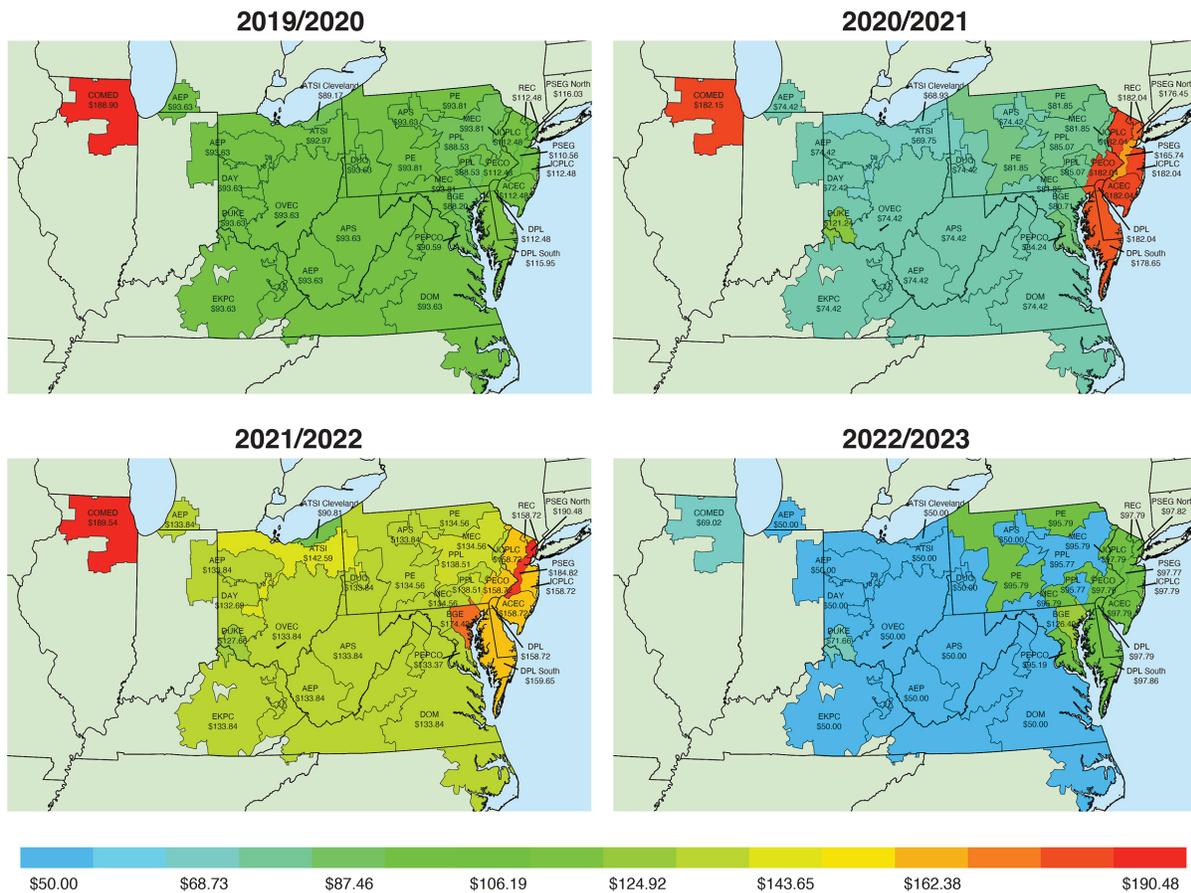


Figure 5-9 Map of RPM capacity prices: 2019/2020 through 2022/2023



126 The 1999/2000 through 2006/2007 capacity prices are CCM combined market, weighted average prices. The 2007/2008 through 2021/2022 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.

Table 5-22 RPM cost to load: 2019/2020 through 2022/2023 RPM Auctions^{127 128 129}

	Net Load Price (\$ per MW-day)	UCAP Obligation (MW)	Annual Charges
2019/2020			
Rest of RTO	\$98.07	89,185.9	\$3,201,364,940
Rest of EMAAC	\$115.58	24,415.1	\$1,032,810,556
BGE	\$97.79	7,595.2	\$271,828,430
COMED	\$192.56	24,985.1	\$1,760,892,086
PEPCO	\$92.90	7,330.3	\$249,230,694
PSEG	\$115.83	11,281.1	\$478,247,326
Total		164,792.8	\$6,994,374,033
2020/2021			
Rest of RTO	\$77.31	69,073.7	\$1,949,098,489
Rest of MAAC	\$87.06	29,555.9	\$939,246,366
EMAAC	\$174.32	35,740.4	\$2,274,098,760
COMED	\$189.92	23,744.7	\$1,645,988,210
DUKE	\$104.50	5,072.0	\$193,459,838
Total		163,186.7	\$7,001,891,663
2021/2022			
Rest of RTO	\$142.16	82,768.3	\$4,294,838,410
Rest of EMAAC	\$164.73	23,719.9	\$1,426,178,211
ATSI	\$160.21	13,995.4	\$818,411,597
BGE	\$163.50	7,491.2	\$447,049,048
COMED	\$198.43	22,721.2	\$1,645,630,168
PSEG	\$188.46	10,987.4	\$755,803,998
Total		161,683.4	\$9,387,911,433
2022/2023			
Rest of RTO	\$50.09	51,125.9	\$934,814,759
EMAAC	\$97.75	35,300.9	\$1,259,545,677
WMAAC	\$96.42	15,495.6	\$545,317,684
BGE	\$107.92	7,611.3	\$299,826,001
COMED	\$67.17	22,940.7	\$562,472,028
DUKE	\$59.38	5,304.6	\$114,962,107
PEPCO	\$95.97	6,698.3	\$234,639,139
Total		144,477.3	\$3,951,577,394

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

¹²⁷ The RPM annual charges are calculated using the rounded, net load prices as posted in the PJM RPM auction results.

¹²⁸ 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.

¹²⁹ The net load prices and obligation MW for 2021/2022 are not finalized.

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.^{130 131 132 133 134 135} The reports showed that the FRR approach is likely to lead to significant increases in payments by customers if it were to replace participation in the PJM markets. The impact on the remaining PJM capacity market footprint is also computed for each scenario. In all but a few scenarios the MMU finds that the FRR leads to higher costs for load included in the FRR service area. In all scenarios the MMU finds that prices in what remains of the PJM Capacity Market would be significantly lower.

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

¹³⁰ 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).

¹³¹ 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).

¹³² 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).

¹³³ 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).

¹³⁴ 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).

¹³⁵ 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).

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.

CRF Issue¹³⁶

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 205.¹³⁷ 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.^{138 139}

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

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

137 "Revisions to Capital Recovery Factor for Avoidable Project Investment Cost Determinations and Request for Waiver of Sixty-Day Notice Requirement," PJM Interconnection LLC, Docket ER21-1844-000 (May 4, 2021).

138 See "Comments of the Independent Market Monitor for PJM," ER21-1844-000 (May 25, 2021).

139 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 ER21-1635-000.

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.¹⁴⁰ FERC rejected the MMU's unit specific state tax recommendation. Going forward, PJM will post the CRFs on their website. Table 5-24 shows the CRFs that are currently posted. The values in Table 5-24 were calculated using the formula above and the financial assumptions in Table 5-25. Bonus depreciation assumptions vary by delivery year with 100 percent bonus depreciation assumed in the 2022/2023 Delivery Year. The bonus depreciation in each subsequent delivery year is reduced by 20 percent.

Table 5-23 Variable descriptions for the CRF formula

Formula Symbol	Description
r	After tax weighted average cost of capital (ATWACC)
s	Effective tax rate
B	Bonus depreciation percent
N	Cost Recovery Period (years)
L	Lesser of N or 16 (years)
m _j	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 5-24, which is identical to the table posted by PJM, includes CRF values for projects that go into service for four identified delivery years but fails to note that these CRF values for a later delivery year would not apply for investments made in prior delivery years that will still be in service in the later delivery year.¹⁴¹ 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

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

141 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>>.

the applicable CRF values would change for all projects, regardless of vintage. As a result, the CRF values in Table 5-24 for delivery years after 2022/2023 would not apply to the calculation of APIR values for projects that go into service for the 2022/2023 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 indicated that the issue is “beyond the scope” of the PJM filing.¹⁴²

Table 5-24 Levelized CRF values: Delivery Year 2022/2023 through Delivery Year 2025/2026

Age of Existing Units (Years)	Remaining Life of Plant	Levelized CRF 2022/2023	Levelized CRF 2023/2024	Levelized CRF 2024/2025	Levelized CRF 2025/2026
1 to 5	30	0.088	0.091	0.094	0.096
6 to 10	25	0.093	0.096	0.098	0.101
11 to 15	20	0.101	0.104	0.107	0.110
16 to 20	15	0.116	0.119	0.122	0.126
21 to 25	10	0.147	0.152	0.158	0.164
25 Plus	5	0.246	0.258	0.271	0.283
Mandatory CapEx	4	0.296	0.312	0.328	0.345
40 Plus Alternative	1	1.100	1.100	1.100	1.100

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

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

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 at least 90 days prior to the proposed deactivation date. 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.¹⁴³ 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.¹⁴⁴

Table 5-26 shows the timing of actual deactivation dates and the initially requested deactivation date, for all deactivation requests submitted from January 2018 through December 2021. Of the 119 deactivation requests submitted, 20 units (16.8 percent) deactivated an average of 214 days earlier than their initially requested date; 12 units (10.1 percent) deactivated an average of 95 days later than the originally requested deactivation date; and 28 units (23.5 percent) deactivated on their initially requested date. Fifteen (12.6 percent) of the unit deactivations were cancelled an average of 351 days before their scheduled deactivation date, and 44 (37.0 percent) of the unit deactivations have not yet reached their target retirement date. Table 5-27 shows this information broken out by fuel types.

Table 5-26 Timing of actual unit deactivations compared to requested deactivation date: Requests submitted January 2018 through December 2021

Status	Number of Units	Percent	Average Days Deviation from Originally Requested Date
Early	20	16.8%	(214)
Late	12	10.1%	95
On time	28	23.5%	0
Cancelled	15	12.6%	(351)
Pending	44	37.0%	-
Total	119	100.0%	-

¹⁴² Order 176 FERC ¶61,003 (July 2, 2021) at 28.

¹⁴³ OATT Attachment DD § 6.6(g).

¹⁴⁴ OATT Part V §113

Table 5-27 Timing of actual unit deactivations compared to requested deactivation date by fuel type: Requests submitted January 2018 through December 2021

Fuel Type	Status	Number of		Average Days Deviation from Originally Requested Date
		Units	Percent	
Biomass	Early	2	100.0%	(4)
	Late	0	0.0%	-
	On time	0	0.0%	-
	Cancelled	0	0.0%	-
	Pending	0	0.0%	-
	Total	2	100.0%	-
Coal	Early	9	25.7%	(268)
	Late	5	14.3%	108
	On time	7	20.0%	0
	Cancelled	2	5.7%	(832)
	Pending	12	34.3%	-
	Total	35	100.0%	-
Diesel	Early	0	0.0%	-
	Late	0	0.0%	-
	On time	0	0.0%	-
	Cancelled	0	0.0%	-
	Pending	4	100.0%	-
	Total	4	100.0%	-
Methane	Early	4	20.0%	(107)
	Late	5	25.0%	75
	On time	7	35.0%	0
	Cancelled	2	10.0%	(190)
	Pending	2	10.0%	-
	Total	20	100.0%	-
Natural Gas	Early	3	20.0%	(262)
	Late	1	6.7%	12
	On time	7	46.7%	0
	Cancelled	0	0.0%	-
	Pending	4	26.7%	-
	Total	15	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	2	7.4%	(326)
	Late	1	3.7%	213
	On time	3	11.1%	0
	Cancelled	1	3.7%	(105)
	Pending	20	74.1%	-
	Total	27	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	0	0.0%	-
	Late	0	0.0%	-
	On time	3	60.0%	0
	Cancelled	0	0.0%	-
	Pending	2	40.0%	-
	Total	5	100.0%	-

Reliability Must Run (RMR) Service

PJM must make out of market payments to units for Reliability Must Run (RMR) service during periods when a unit that would otherwise have been deactivated is needed for reliability.¹⁴⁵ The need for RMR service reflects a flawed market design and/or planning process problems. If a unit is needed for reliability, the market should reflect a locational value consistent with that need which would result in the unit remaining in service or being replaced by a competitor unit. The planning process should evaluate the impact of the loss of units at risk and determine in advance whether transmission upgrades are required.¹⁴⁶

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.¹⁴⁷ PJM performs a system study to determine whether the system can accommodate the deactivation on the desired date, and if not, when it could.¹⁴⁸ If PJM determines that it needs a unit for a period beyond the intended deactivation date, PJM will request a unit to provide RMR service.¹⁴⁹ The PJM market rules do not require an owner to provide RMR service, but owners must provide 90 days advance notice of a proposed deactivation.¹⁵⁰ 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.¹⁵¹ 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.¹⁵²

145 OATT Part V §114

146 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.”).

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

148 OATT § 113.2.

149 *Id.*

150 OATT § 113.1.

151 OATT Attachment DD § 6.6(g).

152 *Id.*

Under the current rules, a unit providing RMR service can recover its costs 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.¹⁵³ Avoidable costs are defined to mean "incremental expenses directly required for the operation of a generating unit."¹⁵⁴ The incentives escalate for each year of service (first year, 10 percent; second year, 20 percent; third year, 35 percent; fourth year, 50 percent).¹⁵⁵ The rules provide terms for early termination of RMR service and for the repayment of project investment by owners of units that choose to keep units in service after the RMR period ends.¹⁵⁶ Project investment is capped at \$2 million, above which FERC approval is required.¹⁵⁷ 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.¹⁵⁸

Table 5-28 shows units that have provided RMR service to PJM. PJM has indicated to another plant that RMR service will be required in 2022.

Table 5-28 RMR service summary

Unit Names	Owner	ICAP				
		(MW)	Cost Recovery Method	Docket Numbers	Start of Term	End of Term
B.L. England 2	RC Cape May Holdings, LLC	150.0	Cost of Service Recovery Rate	ER17-1083	01-May-17	30-Apr-19
Yorktown 1	Dominion Virginia Power	159.0	Deactivation Avoidable Cost Rate	ER17-750	06-Jan-17	08-Mar-19
Yorktown 2	Dominion Virginia Power	164.0	Deactivation Avoidable Cost Rate	ER17-750	06-Jan-17	08-Mar-19
B.L. England 3	RC Cape May Holdings, LLC	148.0	Cost of Service Recovery Rate	ER17-1083	01-May-17	24-Jan-18
Ashtabula	FirstEnergy Service Company	210.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	11-Apr-15
Eastlake 1	FirstEnergy Service Company	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Eastlake 2	FirstEnergy Service Company	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Eastlake 3	FirstEnergy Service Company	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Lakeshore	FirstEnergy Service Company	190.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Elrama 4	GenOn Power Midwest, LP	171.0	Cost of Service Recovery Rate	ER12-1901	01-Jun-12	01-Oct-12
Niles 1	GenOn Power Midwest, LP	109.0	Cost of Service Recovery Rate	ER12-1901	01-Jun-12	01-Oct-12
Cromby 2 and Diesel	Exelon Generation Company, LLC	203.7	Cost of Service Recovery Rate	ER10-1418	01-Jun-11	01-Jan-12
Eddystone 2	Exelon Generation Company, LLC	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.	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	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	453.0	Cost of Service Recovery Rate	ER05-644	25-Feb-05	01-Sep-08

Only two of seven owners have used the deactivation avoidable cost rate approach. The other five owners used the cost of service recovery rate, despite the greater administrative expense.

In each of the cost of service recovery rate filings for RMR 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 RMR service.

The cost of service recovery rate approach has been interpreted by the companies using that approach to allow the company to establish a rate base including investment in the existing plant and new investment necessary to provide RMR service and to earn a return on that rate base and receive depreciation of that rate base. Companies developing the cost of service recovery rate have ignored the tariff's limitation to the costs of operating the unit during the RMR service period and have included costs incurred prior to the decision to the deactivate and costs associated with closing the unit that would have been incurred regardless of the RMR service period.¹⁵⁹ In one cost of service recovery rate, the filing included costs that already had been written

off on the company's public books.¹⁶⁰ Unit owners have filed for revenues under the cost of service method that substantially exceed the actual incremental costs of providing RMR service.

Because an RMR unit is needed by PJM for reliability reasons, and the provision of RMR service is voluntary

153 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).

154 OATT § 115.

155 *Id.*

156 OATT § 118.

157 OATT §§ 115, 117.

158 OATT § 119.

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

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

in PJM, owners of RMR service have significant market power in establishing the terms of RMR service.

RMR service should be provided to PJM customers at reasonable rates, which reflect the riskless nature of providing such service to owners, the reliability need for such service and the opportunity for owners to be guaranteed recovery of 100 percent of the actual incremental costs incurred to provide the service plus an incentive markup.

The cost of service recovery rates have been excessive compared to the actual incremental costs of providing RMR service. The DACR method also provides excessive incentives for service longer than a year, given that customers bear the risks.

The MMU recommends elimination of the cost of service recovery rate in OATT Section 119, that RMR service should be provided under the deactivation avoidable cost rate in Part V, and that the revenue cap under the avoidable cost rate option be eliminated.

The MMU also recommends, based in part on its experience with application of the deactivation avoidable cost rate and proceedings filed under Section 119, the following improvements to the DACR provisions:

- Revise the applicable adders in Section 114 to be 15 percent for the second year of RMR service and 20 percent for the provision of RMR service in excess of two years.
- Add true up provisions that ensure that the RMR service provider is reimbursed for, and consumers pay for, the actual incremental costs associated with the RMR service, plus the applicable adder.
- Eliminate the \$2 million cap on project investment expenditures.
- Clearly distinguish operating expenses and project investment costs.
- Clarify the tariff language in Section 118 regarding the refund of project investment in the event the RMR unit continues operation beyond the RMR term.

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 5-29 shows the capacity factors by unit type for 2020 and 2021. In 2021, nuclear units had a capacity factor of 95.0 percent, compared to 96.1 percent in 2020; combined cycle units had a capacity factor of 61.8 percent in 2021, compared to a capacity factor of 60.1 percent in 2020; coal units had a capacity factor of 42.0 percent in 2021, compared to 34.4 percent in 2020.

Table 5-29 Capacity factor (By unit type (GWh)): 2020 and 2021^{161 162 163}

Unit Type	2020		2021		Change in 2021 from 2020
	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor	
Battery	36.1	1.2%	36.5	1.3%	0.0%
Combined Cycle	289,902.1	60.1%	285,458.6	61.8%	1.6%
Single Fuel	252,301.6	65.6%	251,731.8	69.0%	3.4%
Dual Fuel	37,600.4	38.6%	33,726.8	34.7%	(4.0%)
Combustion Turbine	19,213.8	7.5%	20,320.5	8.0%	0.5%
Single Fuel	13,245.3	7.4%	14,906.4	8.4%	1.0%
Dual Fuel	5,968.5	7.8%	5,414.1	7.1%	(0.7%)
Diesel	282.5	8.3%	311.7	9.1%	0.8%
Single Fuel	273.4	9.0%	292.6	9.5%	0.6%
Dual Fuel	9.1	2.5%	19.1	5.3%	2.8%
Diesel (Landfill gas)	1,560.5	56.2%	1,450.6	55.5%	(0.7%)
Fuel Cell	226.6	90.9%	220.8	88.9%	(2.1%)
Nuclear	276,607.6	96.1%	272,670.4	95.0%	(1.1%)
Pumped Storage Hydro	6,049.3	12.4%	6,091.8	12.5%	0.1%
Run of River Hydro	10,374.0	39.7%	10,533.0	40.4%	0.7%
Solar	3,812.0	16.8%	7,335.0	19.3%	2.5%
Steam	165,306.2	30.2%	189,970.0	36.6%	6.4%
Biomass	5,533.8	65.3%	5,770.9	70.3%	5.0%
Coal	152,358.3	34.3%	178,280.9	42.0%	7.7%
Single Fuel	149,895.3	36.0%	173,535.0	43.0%	7.1%
Dual Fuel	2,463.0	8.9%	4,745.9	22.3%	13.4%
Natural Gas	6,262.9	40.6%	4,878.3	41.1%	0.5%
Single Fuel	426.7	49.5%	523.0	51.7%	2.2%
Dual Fuel	5,836.2	20.5%	4,355.3	18.1%	(2.4%)
Oil	1,151.3	2.6%	1,039.9	3.4%	0.9%
Wind	26,430.7	29.3%	27,650.7	28.4%	(0.9%)
Total	799,801.5	45.2%	822,049.5	47.2%	2.0%

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.¹⁶⁴ 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.¹⁶⁵ If a proposed maintenance outage scheduled within the PJM Peak Period Maintenance Season is not approved by PJM and the generation owner takes the outage, the outage must be classified as a forced outage, or the generation owner may buy replacement capacity, or pay a Peak Season Maintenance Compliance Penalty

¹⁶¹ The capacity factors in this table are based on nameplate capacity values, and are calculated based on when the units come on line.

¹⁶² 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.

¹⁶³ The capacity factor values are modified from previously reported values because of a calculation error which has been fixed.

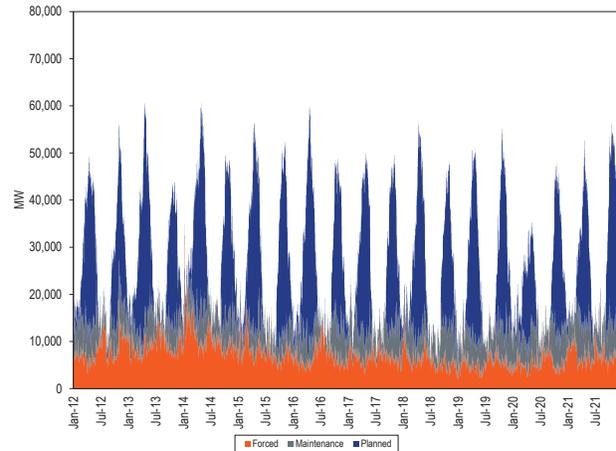
¹⁶⁴ "PJM Manual 10: Pre-Scheduling Operations," § 2.3.2 Maintenance Outage Rules, Rev. 40 (Dec. 15, 2021).

¹⁶⁵ OATT, Attachment K (Appendix) § 1.9.3 (b).

Charge.^{166 167} 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 5-10, as a result of restrictions on planned outages during the winter and summer. The effect of the seasonal variation in outages can be seen in the monthly generator performance metrics in Figure 5-14.

Figure 5-10 Outages (MW): 2012 through 2021



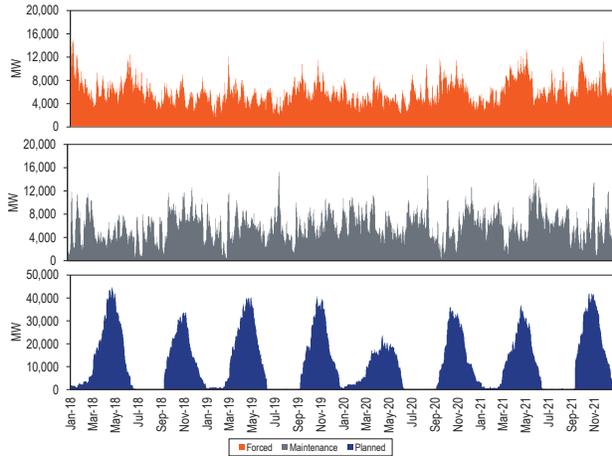
In 2020, planned, maintenance and forced outages were lower than in 2019 (Figure 5-11). The MWh of planned outages were 26 percent lower than in 2019. The MWh of maintenance outages were 7 percent lower than in 2019. The MWh of forced outages were 20 percent lower

¹⁶⁶ OATT, Attachment DD (Reliability Pricing Model) § 9 (b).

¹⁶⁷ PJM "eDART User Guide," Maintenance Outages, Rev. 11 (Feb. 11, 2022), p. 31.

than in 2019. Planned outages were 31 percent higher, maintenance outages were 2 percent higher, and forced outages were 24 percent higher in 2021 than in 2020.

Figure 5-11 Forced, maintenance and planned outages (MW): 2018 through 2021



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 5-12. Metrics by unit type are shown in Table 5-30.

Figure 5-12 Equivalent outage and availability factors: 2007 to 2021

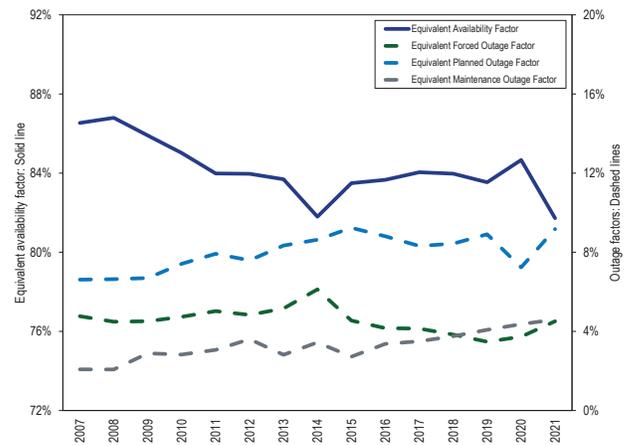


Table 5-30 EFOF, EPOF, EMOF and EAF by unit type: 2007 through 2021

	Coal				Combined Cycle				Combustion Turbine				Diesel			
	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF
2007	7.3%	8.6%	2.7%	81.4%	2.5%	6.1%	1.7%	89.7%	4.4%	2.7%	2.5%	90.4%	10.2%	0.6%	1.6%	87.6%
2008	7.3%	7.1%	2.4%	83.1%	2.1%	6.2%	1.7%	90.0%	2.8%	4.5%	2.2%	90.5%	9.1%	1.0%	1.2%	88.7%
2009	6.6%	8.5%	3.6%	81.3%	2.8%	6.5%	3.3%	87.4%	1.7%	2.8%	2.5%	93.0%	6.6%	0.6%	1.1%	91.7%
2010	7.8%	8.9%	4.1%	79.2%	2.6%	8.4%	3.1%	85.9%	2.1%	2.8%	2.0%	93.1%	4.4%	0.4%	1.5%	93.6%
2011	8.2%	9.2%	4.4%	78.2%	2.5%	9.5%	2.3%	85.7%	2.2%	3.7%	2.4%	91.7%	3.3%	0.1%	1.9%	94.8%
2012	7.6%	9.0%	6.0%	77.4%	3.7%	7.9%	2.2%	86.1%	2.8%	3.4%	1.6%	92.2%	3.9%	0.7%	2.4%	93.0%
2013	8.4%	10.6%	4.5%	76.5%	1.9%	9.1%	2.4%	86.6%	5.3%	4.4%	1.5%	88.8%	6.0%	0.3%	1.4%	92.4%
2014	9.7%	9.8%	5.4%	75.1%	2.7%	10.0%	2.5%	84.7%	6.6%	4.2%	1.8%	87.4%	14.0%	0.4%	2.0%	83.6%
2015	7.7%	10.7%	3.9%	77.7%	2.3%	10.3%	2.0%	85.4%	2.8%	4.7%	1.9%	90.6%	7.7%	0.3%	2.7%	89.3%
2016	7.5%	9.3%	5.9%	77.3%	2.8%	10.6%	1.8%	84.7%	2.0%	5.8%	2.1%	90.1%	5.3%	0.2%	2.6%	91.9%
2017	8.9%	10.4%	6.4%	74.3%	2.1%	10.1%	1.7%	86.2%	1.4%	5.9%	1.9%	90.8%	5.9%	0.4%	2.0%	91.7%
2018	8.3%	11.7%	6.8%	73.2%	1.4%	9.3%	1.4%	87.9%	1.8%	5.6%	1.9%	90.7%	6.2%	0.9%	3.4%	89.6%
2019	7.3%	10.6%	8.0%	74.1%	1.9%	10.4%	1.9%	85.8%	1.8%	6.9%	1.7%	89.7%	7.0%	0.9%	3.0%	89.1%
2020	5.2%	9.0%	9.2%	76.6%	3.9%	8.0%	2.5%	85.6%	4.3%	6.0%	2.0%	87.7%	7.7%	0.1%	3.0%	89.1%
2021	8.0%	14.3%	9.1%	68.5%	2.9%	9.6%	2.4%	85.2%	2.5%	6.0%	3.0%	88.5%	9.3%	0.5%	3.6%	86.6%

	Hydroelectric				Nuclear				Other			
	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF
2007	1.3%	7.3%	1.5%	89.9%	1.4%	5.4%	0.3%	93.0%	5.3%	7.1%	3.3%	84.4%
2008	1.4%	8.2%	2.2%	88.3%	1.8%	5.1%	0.8%	92.3%	4.2%	11.0%	3.3%	81.4%
2009	2.4%	8.7%	2.4%	86.5%	4.2%	4.9%	0.6%	90.2%	3.1%	8.0%	5.0%	83.9%
2010	0.7%	8.5%	2.0%	88.9%	2.4%	5.6%	0.5%	91.6%	4.7%	10.5%	3.7%	81.2%
2011	1.6%	12.1%	1.9%	84.4%	2.7%	5.4%	1.2%	90.7%	5.1%	10.8%	3.3%	80.8%
2012	2.9%	5.8%	2.2%	89.1%	1.6%	6.3%	1.0%	91.1%	5.1%	12.0%	4.2%	78.7%
2013	2.3%	8.2%	2.0%	87.5%	0.9%	5.7%	0.6%	92.8%	6.2%	10.7%	3.4%	79.7%
2014	2.6%	9.6%	3.2%	84.6%	1.6%	5.5%	1.0%	92.0%	6.7%	16.2%	5.2%	71.9%
2015	3.9%	9.9%	1.5%	84.6%	1.4%	5.1%	1.4%	92.1%	6.0%	18.1%	4.3%	71.6%
2016	2.7%	7.9%	3.3%	86.2%	1.6%	5.5%	1.1%	91.8%	4.6%	16.6%	4.6%	74.2%
2017	2.4%	5.9%	3.2%	88.5%	0.5%	5.1%	0.7%	93.7%	4.8%	10.1%	5.7%	79.4%
2018	2.7%	7.7%	3.3%	86.4%	0.7%	4.7%	0.6%	94.0%	3.6%	9.1%	8.2%	79.0%
2019	1.6%	7.1%	3.9%	87.5%	0.6%	5.3%	0.9%	93.2%	3.5%	13.5%	6.7%	76.2%
2020	5.7%	6.9%	2.8%	84.6%	1.4%	4.8%	0.7%	93.1%	19.5%	7.8%	5.5%	67.2%
2021	8.5%	7.7%	2.7%	81.0%	1.0%	4.5%	1.1%	93.3%	6.5%	8.5%	6.7%	78.3%

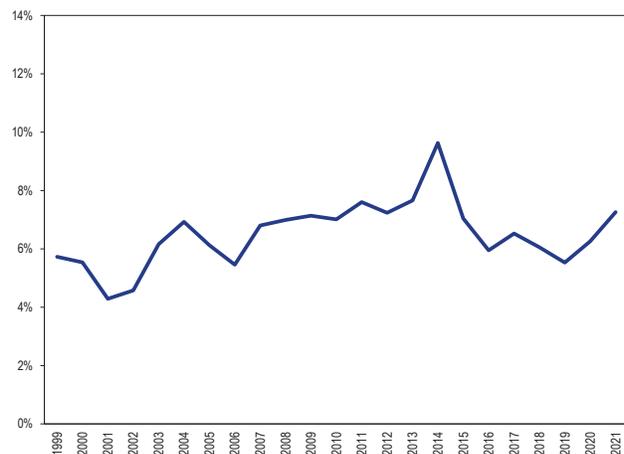
Generator Outage Rates

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.¹⁶⁸ The EFORd metric includes all forced outages, regardless of the reason for those outages.

¹⁶⁸ 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 represent full hours.

The average PJM EFORd in 2021 was 7.3 percent, an increase from 6.3 percent in 2020. Figure 5-13 shows the average EFORd since 1999 for all units in PJM.¹⁶⁹

Figure 5-13 Trends in the equivalent demand forced outage rate (EFORd): 1999 through 2021



¹⁶⁹ The universe of units in PJM changed as the PJM footprint expanded and as units retired from and entered PJM markets. See the 2020 State of the Market Report for PJM, Appendix A: "PJM Overview" for details.

Table 5-31 shows the class average EFORd by unit type.

Table 5-31 EFORd by unit type: 2007 through 2021

	Annual														
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Coal	8.4%	8.4%	8.2%	9.4%	10.5%	10.1%	10.9%	12.2%	9.4%	9.4%	11.4%	11.0%	10.1%	8.6%	11.8%
Combined Cycle	4.0%	3.8%	4.3%	3.8%	3.5%	4.5%	2.6%	4.6%	3.0%	3.5%	2.7%	2.1%	2.7%	3.9%	3.8%
Combustion Turbine	11.5%	11.7%	10.3%	9.7%	8.7%	8.3%	11.1%	16.5%	9.2%	5.6%	5.4%	6.2%	5.3%	4.3%	5.5%
Diesel	11.7%	10.3%	9.3%	6.4%	9.2%	4.8%	6.6%	15.0%	9.0%	6.9%	7.0%	6.7%	7.6%	7.7%	11.6%
Hydroelectric	2.0%	2.1%	3.3%	1.2%	2.9%	4.5%	3.7%	4.0%	5.5%	3.9%	3.4%	3.5%	2.0%	5.7%	10.7%
Nuclear	1.4%	2.0%	4.3%	2.6%	2.9%	1.8%	1.0%	1.8%	1.5%	1.8%	0.5%	0.8%	0.6%	1.4%	1.1%
Other	9.3%	9.9%	8.4%	7.8%	10.1%	9.0%	10.9%	13.3%	13.2%	9.2%	13.7%	9.2%	9.2%	19.5%	17.3%
Total	6.8%	7.0%	7.2%	7.0%	7.6%	7.2%	7.6%	9.6%	7.0%	6.0%	6.5%	6.1%	5.5%	6.3%	7.3%

EFORd vs EAF

EFORd is not an adequate measure of units' availability because EFORd measures only forced outages and does not account for planned or maintenance outages. Forced outage rates can be managed under the existing outage rules. A unit with significant planned and/or maintenance outages is considered to have identical reliability properties in capacity planning, transmission planning and in the sale of capacity in the capacity market.¹⁷⁰ 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 5-32 shows the differences between EFORd and EAF by unit type. For the 2021/2022 Base Residual Auction, total offered UCAP (Unforced Capacity) calculated using the EFORd was 126,452 MW. If EAF were used to calculate available capacity, total available capacity for the 2021/2022 BRA would have been 10.0 percent lower, 114,313 MW.

Table 5-32 EFORd and EAF by unit type: 2012 through 2021

Year	Unit Types															
	Coal		Combined Cycle		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	10.1%	22.6%	4.5%	13.9%	8.3%	7.8%	4.8%	7.0%	4.5%	10.9%	1.8%	8.9%	9.0%	21.3%	7.2%	16.0%
2013	10.9%	23.5%	2.6%	13.4%	11.1%	11.2%	6.6%	7.6%	3.7%	12.5%	1.0%	7.2%	10.9%	20.3%	7.6%	16.3%
2014	12.2%	24.9%	4.6%	15.3%	16.5%	12.6%	15.0%	16.4%	4.0%	15.4%	1.8%	8.0%	13.3%	28.1%	9.6%	18.2%
2015	9.4%	22.3%	3.0%	14.6%	9.2%	9.4%	9.0%	10.7%	5.5%	15.4%	1.5%	7.9%	13.2%	28.4%	7.0%	16.5%
2016	9.4%	22.7%	3.5%	15.3%	5.6%	9.9%	6.9%	8.1%	3.9%	13.8%	1.8%	8.2%	9.2%	25.8%	6.0%	16.3%
2017	11.4%	25.7%	2.7%	13.8%	5.4%	9.2%	7.0%	8.3%	3.4%	11.5%	0.5%	6.3%	13.7%	20.6%	6.5%	16.0%
2018	11.0%	26.8%	2.1%	12.1%	6.2%	9.3%	6.7%	10.4%	3.5%	13.6%	0.8%	6.0%	9.2%	21.0%	6.1%	16.0%
2019	10.1%	25.9%	2.7%	14.2%	5.3%	10.3%	7.6%	10.9%	2.0%	12.5%	0.6%	6.8%	9.2%	23.8%	5.5%	16.5%
2020	8.6%	23.4%	3.9%	13.8%	4.3%	9.6%	7.7%	9.7%	5.7%	13.9%	1.4%	6.8%	19.5%	22.2%	6.3%	15.3%
2021	11.8%	31.5%	3.8%	14.8%	5.5%	11.5%	11.6%	13.4%	10.7%	19.0%	1.1%	6.7%	17.3%	21.7%	7.3%	18.3%
Average	10.5%	24.9%	3.3%	14.1%	7.7%	10.1%	8.3%	10.3%	4.7%	13.9%	1.2%	7.3%	12.4%	23.3%	6.9%	16.5%

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.¹⁷¹ 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).

¹⁷⁰ OATT, Attachment DD (Reliability Pricing Model) § 10A (d).

¹⁷¹ 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 EFOF was 4.5 percent in 2021. Table 5-33 shows the causes of EFOF by unit type. Forced outages for boiler tube leaks, 18.3 percent of the system EFOF, were the largest single contributor to EFOF.

Table 5-33 Contribution to EFOF by unit type by cause: 2021

	Combined		Combustion		Diesel	Hydroelectric	Nuclear	Other	System
	Coal	Cycle	Turbine						
Boiler Tube Leaks	28.1%	6.4%	0.0%	0.0%	0.0%	0.0%	0.0%	12.4%	18.3%
Electrical	6.4%	14.5%	9.9%	2.9%	18.5%	22.7%	1.2%		8.7%
Generator	7.8%	16.6%	1.9%	7.7%	2.8%	0.0%	2.4%		7.1%
Turbine	0.0%	0.7%	11.8%	0.0%	70.6%	0.0%	0.0%		6.1%
Unit Testing	2.7%	10.9%	23.5%	27.9%	2.6%	1.4%	6.9%		5.9%
Feedwater System	8.4%	4.5%	0.0%	0.0%	0.0%	3.6%	0.3%		5.6%
Controls	0.8%	3.8%	0.9%	6.6%	0.1%	6.8%	34.4%		4.6%
Boiler Air and Gas Systems	6.5%	0.1%	0.0%	0.0%	0.0%	0.0%	3.1%		4.1%
Wet Scrubbers	5.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%		3.3%
Miscellaneous (Steam Turbine)	2.3%	5.7%	0.0%	0.0%	0.0%	0.0%	1.7%		2.2%
Condensing System	2.6%	0.8%	0.0%	0.0%	0.0%	12.1%	0.3%		2.2%
Auxiliary Systems	0.9%	5.7%	7.3%	0.1%	0.3%	2.5%	0.2%		2.0%
Economic	0.2%	1.4%	1.3%	2.0%	2.1%	0.0%	14.1%		1.9%
Boiler Fuel Supply from Bunkers to Boiler	3.1%	0.3%	0.0%	0.0%	0.0%	0.0%	0.8%		1.9%
Miscellaneous (Gas Turbine)	0.0%	2.9%	17.0%	0.0%	0.0%	0.0%	0.0%		1.8%
Circulating Water Systems	2.1%	3.2%	0.0%	0.0%	0.0%	2.8%	0.0%		1.7%
High Pressure Turbine	2.6%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%		1.6%
Boiler Piping System	2.1%	1.3%	0.0%	0.0%	0.0%	0.0%	1.2%		1.5%
Valves	2.1%	1.6%	0.0%	0.0%	0.0%	0.3%	0.6%		1.5%
All Other Causes	15.6%	19.5%	26.5%	52.9%	2.9%	47.7%	20.3%		18.2%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%		100.0%

The PJM EMOF was 4.6 percent in 2021. Table 5-34 shows the causes of EMOF by unit type. Maintenance outages for boiler tube leaks, 10.3 percent of the system EMOF, were the second largest contributor to the system EMOF. Overhauling and inspecting boilers, 12.1 percent of the system EMOF, was the largest contributor to system EMOF. The causes of maintenance outages for diesel and hydroelectric units differed from the other technology types. The largest contributor to EMOF for diesel units and for hydroelectric units was “All Other Causes.”

Table 5-34 Contribution to EMOF by unit type by cause: 2021

	Combined		Combustion		Diesel	Hydroelectric	Nuclear	Other	System
	Coal	Cycle	Turbine						
Boiler Overhaul and Inspections	16.4%	8.3%	0.0%	0.0%	0.0%	0.0%	13.6%		12.1%
Boiler Tube Leaks	14.3%	13.9%	0.0%	0.0%	0.0%	0.0%	3.5%		10.3%
Electrical	5.3%	6.8%	30.6%	1.4%	12.8%	0.0%	6.4%		8.4%
Boiler Air and Gas Systems	10.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.9%		6.2%
Miscellaneous (Gas Turbine)	0.0%	18.9%	23.9%	0.0%	0.0%	0.0%	0.0%		4.7%
Miscellaneous (Reactor)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	76.0%		3.9%
Miscellaneous (Balance of Plant)	1.9%	5.2%	3.1%	0.0%	2.5%	0.0%	12.4%		3.4%
Feedwater System	3.1%	0.2%	0.0%	0.0%	0.0%	0.0%	14.1%		3.4%
Auxiliary Systems	3.5%	1.7%	5.6%	0.0%	0.4%	0.0%	3.0%		3.2%
Boiler Piping System	3.4%	8.1%	0.0%	0.0%	0.0%	0.0%	1.1%		3.0%
Precipitators	4.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%		2.9%
Wet Scrubbers	4.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%		2.9%
Dry Scrubbers	4.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%		2.6%
Condensing System	3.0%	1.5%	0.0%	0.0%	0.0%	0.5%	2.8%		2.3%
High Pressure Turbine	2.8%	0.5%	0.0%	0.0%	0.0%	2.6%	0.6%		1.9%
Circulating Water Systems	1.5%	3.7%	0.0%	0.0%	0.0%	4.8%	2.9%		1.8%
Miscellaneous (Boiler)	1.8%	0.3%	0.0%	0.0%	0.0%	0.0%	4.7%		1.6%
Boiler Tube Fireside Slagging or Fouling	2.4%	0.0%	0.0%	0.0%	0.0%	0.0%	1.1%		1.5%
Fuel, Ignition and Combustion Systems	0.0%	4.3%	9.0%	0.0%	0.0%	0.0%	0.0%		1.5%
All Other Causes	16.1%	26.5%	27.8%	98.5%	84.3%	16.1%	32.8%		22.4%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%		100.0%

PJM EPOF was 9.2 percent in 2021. Table 5-35 shows the causes of EPOF by unit type. The single largest contributor, 24.7 percent of system EPOF, was planned outages for inspecting and overhauling boilers. The causes of maintenance

outages for diesel and hydroelectric units differed from the other technology types. The largest contributor to EPOF for diesel units and for hydroelectric units was “All Other Causes.”

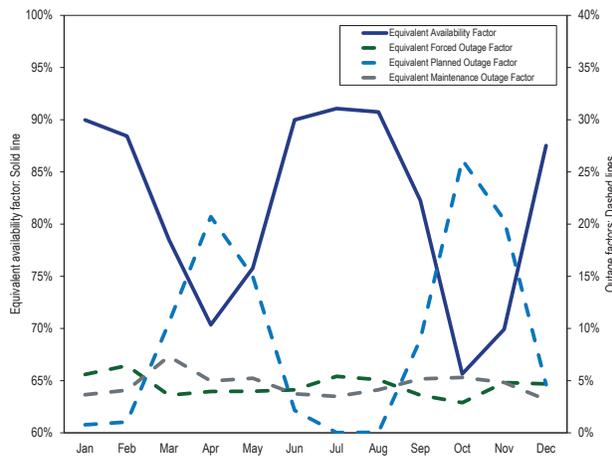
Table 5-35 Contribution to EPOF by unit type and cause: 2021

	Combined		Combustion Turbine	Diesel	Hydroelectric	Nuclear	Other	System
	Coal	Cycle						
Boiler Overhaul and Inspections	41.4%	4.0%	0.0%	0.0%	0.0%	0.0%	60.5%	24.7%
Miscellaneous (Gas Turbine)	0.0%	46.3%	55.6%	0.0%	0.0%	0.0%	0.0%	15.5%
Miscellaneous (Balance of Plant)	14.7%	19.0%	11.2%	0.0%	7.0%	0.2%	6.6%	12.9%
Core/Fuel	0.0%	0.0%	0.0%	0.0%	0.0%	93.5%	0.0%	9.6%
Miscellaneous (Steam Turbine)	5.9%	8.2%	0.0%	0.0%	0.0%	0.0%	0.6%	4.5%
NOx Reduction Systems	5.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.6%
Electrical	2.3%	1.9%	6.3%	0.5%	0.4%	0.0%	5.7%	2.6%
Boiler Piping System	3.8%	2.3%	0.0%	0.0%	0.0%	0.0%	3.2%	2.5%
Generator	0.0%	1.3%	3.3%	0.0%	35.3%	0.0%	1.1%	2.0%
Boiler Tube Leaks	3.2%	0.5%	0.0%	0.0%	0.0%	0.0%	0.1%	1.6%
Wet Scrubbers	3.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.6%
Low Pressure Turbine	2.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.3%
Miscellaneous (Generator)	0.7%	1.1%	5.0%	0.0%	2.2%	0.0%	0.7%	1.2%
Boiler Air and Gas Systems	2.3%	0.0%	0.0%	0.0%	0.0%	0.0%	1.1%	1.2%
Miscellaneous (Boiler)	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	16.9%	1.2%
Controls	2.2%	0.1%	0.5%	0.0%	0.0%	0.4%	0.2%	1.2%
Fuel, Ignition and Combustion Systems	0.0%	4.0%	3.3%	0.0%	0.0%	0.0%	0.0%	1.2%
Boiler Tube Fireside Slagging or Fouling	2.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.0%
Condensate System	0.0%	4.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.9%
All Other Causes	10.0%	6.8%	14.6%	99.5%	55.2%	5.9%	3.3%	10.7%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Performance by Month

On a monthly basis, unit availability as measured by the equivalent availability factor is shown in Figure 5-14.

Figure 5-14 Monthly generator performance factors: 2021



Generator Testing

PJM’s testing requirements are not well designed, permit excessive generator discretion and do not require adequate winter testing. Summer/Winter Capability Testing, also known as Net Capability Verification Testing, is designed to demonstrate whether a resource

has the ICAP claimed.¹⁷² Generation owners perform these tests during the summer and winter test periods, but may use data collected in the summer for winter testing after adjusting for ambient winter conditions. 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. An owner can perform an unlimited number of tests during the testing period before a successful result. Test results must be submitted via eGADS. Generators are required to report failed tests and to derate their unit in eGADS. Failure to report and derate the unit can result in a Generation Resource Rating Test Failure Charge. Generation owners also have the option to buy replacement capacity that satisfies the same locational requirements.^{173 174}

172 “PJM Manual 18: PJM Capacity Market,” § 8.5 Summer/Winter Capability Testing, Rev. 51 (Oct. 20, 2021).

173 “PJM Manual 21: Rules and Procedures for Determination of Generating Capability,” § 1.3.6 Impacts of Test Results, Rev. 16 (Aug. 1, 2021).

174 OAT, Attachment DD (Reliability Pricing Model) § 7 (a).

