Analysis of the 2023/2024 RPM Base Residual Auction

The Independent Market Monitor for PJM

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Introduction

This report, prepared by the Independent Market Monitor for PJM (IMM or MMU), reviews the functioning of the seventeenth Reliability Pricing Model (RPM) Base Residual Auction (BRA) for the 2023/2024 Delivery Year which was held from June 8 to 14, 2022, and responds to questions raised by PJM members and market observers about that auction.[1] The MMU prepares a report for each RPM Base Residual Auction.

This report addresses, explains and quantifies the basic market outcomes in the 2023/2024 BRA. This report also addresses and quantifies the impact on market outcomes of: the shape of the existing VRR curve; a VRR rotated half way towards a vertical curve; the overstatement of forecast peak load; the changes in Capacity Emergency Transfer Limits (CETL); the overstatement of intermittent capacity values; the inclusion of Demand Resources (DR); the inclusion of Energy Efficiency resources (EE) and the EE addback mechanism; the inclusion of Price Responsive Demand (PRD); the inclusion of seasonal products; the use of seasonal matching; the inclusion of capacity imports; and offers for nuclear resources.[2]

The combined impact of the identified market design flaws was to reduce capacity market revenues by 24.3 percent in the 2023/2024 BRA. The identified market design flaws are: the shape of the VRR curve; the overstatement of intermittent MW offers; the inclusion of sell offers from DR; and capacity imports.

This report also addresses additional issues including: market power; the market seller offer cap (MSOC); MOPR; the capacity must offer requirement; the definition of avoidable costs; the use of forward looking net revenues; the matching of seasonal offers; Capacity Transfer Rights (CTRs) and the market clearing model used by PJM.

The market power rules applied in the 2021/2022 BRA and the 2022/2023 BRA were significantly flawed, as illustrated by the results of the 2021/2022 BRA and the 2022/2023 BRA.[3] Competitive outcomes require continued improvement of the rules and ongoing

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1 The BRA for the 2023/2024 Delivery Year had been scheduled for May 2020.

2 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.

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

monitoring of market participant behavior and market performance. The incorrect definition of the offer caps in the 2021/2022 BRA and the 2022/2023 BRA resulted in noncompetitive offers and noncompetitive outcomes in both auctions. The market power rules were corrected by the Commission in an order issued on September 2, 2021, (September 2nd Order) but the modified market power rules were not implemented in the 2022/2023 BRA.[4] The result was that capacity market prices were above the competitive level in the 2022/2023 BRA. The corrected MSOC rules were applied in the 2023/2024 BRA and were essential to the competitive results of the 2023/2024 BRA.

The MMU concludes that the results of the 2023/2024 Base Residual Auction were competitive.

Capacity market prices in the 2023/2024 BRA were the result of both competitive forces and significantly flawed market design. The corrected MSOC rules resulted in competitive offers and prevented noncompetitive offers. Other elements of the market design suppressed prices. The lower clearing prices in 2023/2024 BRA were the combined result of lower offer prices, higher CETL limits, lower gross CONE values, subsidies to select generation resources, slightly reduced demand, and a change in cleared MW by technology. Cleared MW from coal resources decreased 5,698.8 MW from the 2022/2023 RPM Base Residual Auction while cleared MW from nuclear resources increased 5,314.8 MW from the 2022/2023 RPM Base Residual Auction. The lower offer prices reflected the significant change in the energy market fundamentals. Competitive capacity market offers reflect, regardless of tariff requirements, participants' forward looking expectations of profits from the energy market and therefore the revenue they require from the capacity market. The spark spread is a measure of the difference between the energy price and the cost of gas required to generate the energy at a defined heat rate. The forward looking peak hour spark spread in the period prior to the 2023/2024 BRA was about 134 percent higher than the forward looking peak hour spark spread in the period prior to the 2022/2023 BRA. The weighted average sell offer for existing generation capacity resources was less than half the weighted average market seller offer cap.

The capacity market exists to make the energy market work, by providing the additional net revenues required for the incentive to invest in new units and to maintain old units. The definition of capacity is not the ability to provide energy during one peak hour or five peak hours, as implied by the methods used by PJM and LSEs to allocate the costs of capacity to load. The obligations of capacity resources include the requirement to offer

Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20222023_RPM_BRA_20220222.pdf>.

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

their full ICAP in the day-ahead energy market every day. The need for the energy from capacity is not limited to one peak hour or five peak hours. Customers require energy from capacity resources all 8,760 hours per year. Rather than develop a complicated seasonal capacity market based on an arbitrary definition of seasons, the daily and even hourly value of the energy from capacity should be explicitly recognized in the capacity market. Under that approach, products with different characteristics at different times of the year (so called seasonal products) would not need to be matched with peak period products.

Conclusions and Recommendations

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

PJM's required demand for capacity, based on reliability requirements, includes expected peak load plus a required reserve margin, but most points on the downward sloping part of the demand curve, the (VRR curve, exceed peak load plus the reserve margin. The shape of the VRR curve results in the purchase of excess capacity and substantially higher payments by customers. The required demand for capacity defines a vertical demand curve equal to expected peak load plus a required reserve margin. The impact of the VRR curve shape used in the 2023/2024 BRA compared to a vertical demand curve was significant. Use of the VRR curve increased the purchase of capacity 10.1 percent, and increased the total load payments for capacity by $983 million, or an increase of 81.1 percent compared to a vertical demand curve.

The level of cleared demand resources (8,203.3 MW) is slightly greater than the entire excess (7,835.3 MW). PJM has not, and is not, relying on demand response for reliability in actual operations. The excess has hidden the impact 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, and associated energy market prices, whenever called.

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

The market design for capacity leads, almost unavoidably, to structural market power in the capacity market. The capacity market is unlikely ever to approach a competitive market structure in the absence of a substantial and unlikely structural change that results in much greater diversity of ownership. Market power is and will remain endemic to the structure of the PJM Capacity Market. Nonetheless a competitive outcome can be assured by appropriate market power mitigation rules. 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.[5] Competitive outcomes require continued improvement of the rules and ongoing monitoring of market participant behavior and market performance. The incorrect definition of the offer caps in the 2021/2022 BRA and the 2022/2023 BRA resulted in noncompetitive offers and noncompetitive outcomes in both auctions. The market power rules were corrected by the Commission in an order issued on September 2, 2021, (September 2nd Order) but the modified market power rules were not implemented in the 2022/2023 BRA.[6] The result was that capacity market prices were above the competitive level in the 2022/2023 BRA.

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

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

6 176 FERC ¶ 61,137 (September 2nd Order).

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 market seller offer cap defines a competitive offer in the capacity market, regardless of whether the concern is efforts to increase the market price above the competitive level or to reduce the market price below the competitive level. It is basic economics that a competitive offer is a competitive offer. There is not one competitive offer for those who would suppress market prices and another one for those would inflate market prices. As in all other markets, the competitive offer in the capacity market is the marginal cost of capacity.

The definition of the market seller offer cap was changed with the introduction of the Capacity Performance (CP) rules, from offer caps based on the marginal cost of capacity to offer caps based on Net CONE. But the derivation of the CP market seller offer cap was based on PJM's assertion that the target price of the capacity market should be Net CONE, and simply assumed the answer. The CP market seller offer cap was incorrectly and significantly overstated as a result.

PJM's filing of the CP design made clear that PJM was abandoning offer caps that were based on verifiable calculations of the marginal cost of providing capacity in favor of an approach that explicitly relied on wishful thinking about competitive forces resulting in competitive offers, despite the fact that the filing elsewhere recognized the high levels of concentration and the need to protect against market power in the capacity market.[7] PJM ignored the economic logic of marginal cost. PJM simply asserted that Net CONE was the target clearing price of the capacity market. PJM's filing explicitly stated that "By design, over time the marginal offer needed to clear the market will be priced at Net CONE, and all other resources that clear the market will be compensated at that Net CONE price."[8] PJM did not include a derivation of the offer cap in its CP filing, but simply asserted that Net CONE was the definition of a competitive offer.[9] There was not a single reference to opportunity cost as the basis for the market seller offer cap in the PJM filing.

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

[8] See page 55 of CP Filing.

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

In subsequent filings, PJM included the mathematical derivation of the market seller offer cap.[10] But the circular logic of the derivation inevitably concluded that Net CONE times B was the competitive offer. There were two key assumptions that led to that result. The derivation started by assuming that Net CONE was the target clearing price for the capacity market. PJM stated, in explaining the penalty rate, "Net CONE is the proper measure of the value of capacity."[11] That assumption/assertion was the basis for using Net CONE as the penalty rate. The penalty rate, adjusted for the reduced obligation defined by B, became the market seller offer cap. In addition to assuming the answer by setting the penalty rate based on net CONE, the second key counterfactual assumption was that capacity resources have the ability to costlessly switch between capacity resource status and energy only status.

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

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

The MMU supported the modified CP filing and prepared the mathematical appendix.[12] But, after evaluating the offer behavior and results of the capacity market auctions under CP and the actual PAI evidence and the failure to include updated PAI data in the definition of the offer cap, it became clear to the MMU that the CP model was a mistake.[13]

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10 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).

11 See page 43 of CP Filing.

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

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

The market seller offer cap of Net CONE times B was ultimately a failed experiment based on the third demonstrably false assumption that competitive forces in the PJM Capacity Market would produce competitive outcomes despite an offer cap that was above the competitive level. The structure of the PJM Capacity Market is not competitive and the purpose of market power mitigation is to produce competitive results despite that fact. The Net CONE times B offer cap assumed competition where it did not exist and led to noncompetitive outcomes and led to customers being overcharged by a combined $1.454 billion in the 2021/2022 and 2022/2023 BRAs.[14] The logical circularity of the argument as well as the fact that key assumptions are incorrect, means that the CP market seller offer cap was not based on economics or logic or math.

The correct definition of a competitive offer is the marginal cost of capacity, net ACR, where ACR includes an explicit accounting for the costs of mitigating risk, including the risk associated with capacity market nonperformance penalties, and the relevant costs of acquiring fuel, including natural gas. In response to a complaint filed by the MMU, the Commission replaced the Net CONE times B market seller offer cap with an ACR offer cap in the September 2nd Order.[15] [16]

The MMU, as part of the process for all BRAs, verifies the reasonableness of avoidable cost data and calculations; calculates unit specific net revenues; calculates the derived offer caps based on submitted data for resources that submitted unit specific data and for resources that submitted offers based on default ACR values; reviews Minimum Offer Price Rule (MOPR) unit specific exception requests; reviews offers for Planned Generation Capacity Resources; verifies capacity exports, including firm contracts and export offers based on opportunity costs; reviews requests for exceptions to the RPM must offer requirement; reviews requests for exceptions to the additional, specific CP must offer requirement; verifies the sell offer Equivalent Demand Forced Outage Rates (EFORds);

(December 13, 2019); Comments of the Independent Market Monitor, Docket No. ER15-623, EL15-29 and EL19-47 (December 17, 2020).

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

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

16 174 FERC ¶ 61,212; 176 FERC ¶ 61,137; *order on reh'g*, 178 FERC ¶ 61,121.

reviews requests for alternate maximum EFORds; reviews documentation for Intermittent Resources and Capacity Storage Resources to support CP eligibility; verifies clearing prices based on the supply and demand (VRR) curves; and verifies that the market power tests were applied correctly.[17]

All participants to which the three pivotal supplier (TPS) test was applied (in the RTO, MAAC, DPL South, and BGE RPM markets) failed the three pivotal supplier test. The result was that offer caps were applied to all sell offers for Existing Generation Capacity Resources when the capacity market seller did not pass the test, the submitted sell offer exceeded the tariff defined offer cap, and the submitted sell offer, absent mitigation, would have resulted in a higher market clearing price.[18] [19]

Based on the data and this review, the MMU concludes that the results of the 2023/2024 RPM Base Residual Auction were competitive. A competitive offer in the capacity market is equal to net ACR.[20] The ACR values were based on data provided by the participants and were consistent with competitive offers for the relevant capacity.

The MMU also concludes that market prices were significantly affected by flaws in the capacity market rules and in the application of the capacity market rules by PJM, including the shape of the VRR curve; the overstatement of intermittent MW offers; the inclusion of sell offers from DR; and capacity imports.

The MMU also concludes that, although not an issue in the 2023/2024 auction, the rules permit the exercise of market power without mitigation for seasonal products through

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17 Attachment A reviews why the MMU calculation of clearing prices differs slightly from PJM's calculation of clearing prices and includes recommendations for improving the market clearing algorithm.

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

19 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).

20 174 FERC ¶ 61,212 ("March 18th Order") at 65.

uplift payments for noncompetitive offers, rather than through higher prices.[21] Although the impact did not arise in the 2023/2024 auction, the issue should be addressed immediately in order to prevent the impact from increasing and because the solution is simple.

Changes to the capacity market design have addressed some but not all of the significant recommendations made by the MMU in prior reports. The MMU had recommended the elimination of the 2.5 percent demand adjustment (Short-Term Resource Procurement Target). The MMU had recommended that the performance incentives in the capacity market design be strengthened. The MMU had recommended that generation capacity resources pay penalties if they fail to produce energy when called upon during any of the hours defined as critical. The MMU had recommended that the net revenue calculation used by PJM to calculate the Net Cost of New Entry (CONE) VRR parameter reflect the actual flexibility of units in responding to price signals rather than using assumed fixed operating blocks that are not a result of actual unit limitations. The MMU had recommended that all capacity imports be required to be pseudo tied in order to ensure that imports are as close to full substitutes for internal, physical capacity resources as possible. The MMU had recommended that the definition of demand side resources be modified in order to ensure that such resources are full substitutes for and provide the same value in the capacity market as generation resources, although this recommendation has not been incorporated in PJM rules. The MMU had recommended that both the Limited and the Extended Summer DR products be eliminated and that the restrictions on the availability of Annual DR be eliminated in order to ensure that the DR product has the same unlimited obligation to provide capacity year round as Generation Capacity Resources. The MMU had recommended that the EE addback calculation be corrected. The MMU had recommended that the default Avoidable Cost Rate (ACR) escalation method be modified in order to ensure accuracy and eliminate double counting.

The MMU recommends that PJM evaluate the shape of the VRR curve. The shape of the VRR curve directly results in load paying substantially more for capacity than load would pay with a vertical demand curve. More specifically, the MMU recommends that the VRR curve be rotated half way towards the vertical demand curve at the reliability requirement for the current Quadrennial Review. The shape of the VRR curve was discussed in the stakeholder process, PJM reviewed the impact of a range of VRR shape options, and PJM

21 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.

agreed that the VRR curve should be rotated towards the vertical demand curve, but by only approximately one quarter of the way towards vertical.[22]

The MMU recommends that PJM not sell back any capacity in any IA, at much lower prices, procured in a BRA. If excess capacity is procured in a BRA at very significant cost to load, that capacity should not be sold back at a steep discount. Given PJM's assertions of the benefits of over procuring capacity, it has never been explained why load should pay a high price for capacity in a BRA and sell it back at very low prices in an IA. Such sales are inconsistent with PJM's assertion that additional capacity purchases have value.[23] In addition, such sales suppress prices in incremental auctions and provide inefficient incentives for demand resource offer behavior and others with an incentive to replace capacity sales.[24]

The MMU recommends the enforcement of a consistent definition of a capacity resource. The MMU recommends that the tariff requirement to be a physical resource be enforced and enhanced. The requirement to be a physical resource should apply at the time of auctions and should also constitute a commitment to be physical in the relevant delivery year. The requirement to be a physical resource should be applied to all resource types, including planned generation, demand resources, energy efficiency, and imports.[25] [26] The requirement to be a physical resource is not currently applied to DR and EE, both of which are permitted to submit marketing plans rather than evidence of physical resources in the BRA. All DR should be on the demand side of the market rather than on the supply side. If DR remains on the supply side, it should be required to be an economic resource rather than a purely emergency resource and to have all the obligations of any other capacity

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

23 "PJM Manual 18: PJM Capacity Market," § 3.1 Overview of Demand in the Reliability Pricing Model, Rev. 54 (Sep. 21, 2022).

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

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

26 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).

resource. EE should be removed from the capacity market because it is now accounted for in PJM load forecasts. In addition, the rules governing the actual EE resources are inadequate to ensure that the significant payments by capacity market customers are changing any actual behavior by EE program participants.

The MMU recommends that intermittent resources, including storage, not be permitted to offer capacity MW based on energy deliveries that exceed the CIRs assigned to such resources. Correctly defined derating factors will be lower than the CIRs required to meet those derating factors. It is not adequate that intermittent resources, including storage, not be permitted to offer capacity MW greater than the CIR values assigned to and, when required, paid for by such resources. For intermittent resources, including storage, that is a necessary but not sufficient condition for the correct level of capacity MW. Intermittent resources' CIR values generally exceed the correctly defined level of capacity because the derated value (including derating based on ELCC) of capacity MW is based on energy deliveries in excess of the derated value. The derated ELCC values are generally based on energy deliveries equal to the full maximum output capability of the resource. The deliverable energy, required for capacity resource status, is based on CIRs. Derating factors initially and now derating factors based on 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. The ELCC capacity derating factors applied to intermittent nameplate capacity in the 2023/2024 BRA were based on the incorrect assumption that the intermittent resources provide reliable output in excess of their CIRs. But that output, in excess of CIRs, is not deliverable when needed for reliability because it is in excess of the formally defined deliverability rights (CIRs) and therefore is not reliable output as assumed and therefore should not be included in the definition of intermittent capacity. Any generation from a resource in excess of its CIR value is equivalent to generation from an energy only resource and should not be included in the calculation of the capacity value of the resource or in the calculation of the derated ELCC class ratings that define the capacity value of the resource.[27] [28] PJM recalculated the ELCC class ratings for wind and solar resources assuming the generation from an ELCC resource is capped at its CIR level.[29] The revised

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27 See OATT Attachment O § 2.1(a).

28 See RAA Schedule 9.1, Schedule H ("Energy Resources are not included in the effective load carrying capability analysis.").

29 "Impact on Wind & Solar Class UCAP Values by Capping Hourly Outputs in UCAP Calculation at CIR Level," Item 4A in meeting notes for PC Special Session – CIRs for ELCC

class rating for onshore wind is 8.0 percent, 46.7 percent lower than the original class rating of 15.0 percent. The revised rating for fixed solar is 33.0 percent, 13.2 percent lower than the original class rating of 38.0 percent. The revised rating for tracking solar is 51.0 percent, 5.6 percent lower than the original class rating of 54.0 percent.[30]

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

The MMU recommends that the must offer rule in the capacity market apply to all capacity resources. There is no reason to exempt intermittent and capacity storage resources, including hydro and demand resources and energy efficiency resources from the must offer requirement. The same rules should apply to all capacity resources. The purpose of the must offer rule, which has been in place since the beginning of the capacity market in 1999, is to ensure that the capacity market works based on the inclusion of all demand and all supply, and to prevent the exercise of market power via withholding of supply. The failure to apply the must offer requirement will create increasingly significant market design issues and market power issues in the capacity market as the level of capacity from intermittent and storage resources increases and the level of demand side resources remains high. The failure to apply the must offer requirement consistently could also create price volatility and uncertainty in the capacity market and put PJM's reliability margin at risk. The capacity market was designed on the basis of a must buy requirement for load and a corresponding must offer requirement for capacity resources. The capacity market can work only if both are enforced.

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

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Resources, PJM Interconnection LLC, May 19, 2022 <https://pjm.com/committees-and-groups/committees/pc>.

30 These issues have been the subject of lengthy stakeholder discussions in the Capacity Capability Senior Task Force <https://pjm.com/committees-and-groups/closed-groups/ccstf> and the Planning Committee (PC) Special Session – CIRs for ELCC Resources <https://www.pjm.com/committees-and-groups/committees/pc>.

tariff distinction between mothball and retirement avoidable costs is unsupported and should be eliminated. Avoidable costs are defined by the OATT to be the costs that a generation owner incurs as a result of operating a generating unit for one year, in particular the delivery year.[31] 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. Avoidable costs are costs that are neither short run marginal costs, like fuel or consumables, nor fixed costs like depreciation and rate of return. The MMU also 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.[32]

The MMU recommends that Energy Efficiency Resources (EE) not be included in the capacity market because PJM's load forecasts now account for EE, unlike the situation when EE was first added to the capacity market.[33] EE should not be part of the capacity market. EE is appropriately and automatically compensated through the markets because it reduces energy and capacity use and therefore customer payments for energy and capacity. EE is appropriately incorporated in PJM forecasts, so the original logic for the inclusion of EE in the capacity market is no longer correct. While EE does not affect the clearing price when the EE addback is done correctly, customers do pay for the cleared quantity of EE at market clearing prices. These direct payments to EE in the capacity market are an overpayment by customers.

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

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31 OATT Attachment DD § 6.8 (b).

32 *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).

33 "PJM Manual 19: Load Forecasting and Analysis," § 3.2 Development of the Forecast, Rev. 35 (Dec. 31, 2021).

ACR. This recommendation was rejected by FERC.[34] The FERC approved approach, used in the 2021/2022, 2022/2023 and 2023/2024 BRAs, requires use of the price-based offer in most cases. The FERC approach requires the use of the cost-based offer when the resource offer is mitigated for market power and the cost-based offer is lower than the price-based offer. The FERC approach also requires the use of the cost-based offer when the price based offer is less than fuel costs plus environmental costs, even if the cost-based offer is greater than fuel cost plus environmental costs.[35] The higher the energy offer used in the calculation of net revenues, the lower the net revenues and the higher the net ACR offer cap. The FERC approach, used in most cases, results in lower net revenues and higher offer caps than calculated under the MMU approach.

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

But the current PJM method for calculating forward looking E&AS net revenues includes an adjustment based on the prices of long term FTRs for the planning period closest in time to the delivery year which requires an adjustment for monthly average day-ahead congestion price differentials and an adjustment for loss component differentials of historical LMPs. Use of the adjustment based on the prices of long term FTRs adds unnecessary complexity, fails to make the result more accurate, makes the results less transparent, and in some cases make the results less accurate. PJM's use of long term FTRs in the forward energy market price calculation does not use the FTR auction for the desired delivery year as a result of the timing of capacity auctions and FTR auctions when PJM is on its defined three year capacity market auction schedule. The MMU recommends the use of forward LMPs calculated using real-time monthly on and off peak forward prices for the delivery year at the PJM Western Hub, adjusted to the zone and hour using the historical zonal, nodal and hourly real-time price differentials for each of the last three years. The MMU and PJM have been implementing this method for years in the

34 See 155 FERC ¶ 61,281 (2016).

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

calculation of the opportunity costs associated with environmental limits on the operation of generating units.[36]

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

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

The MMU recommends that, as part of the MOPR unit specific standard of review, all projects be required to use the same basic modeling assumptions. That is the only way to ensure that projects compete on the basis of actual costs rather than on the basis of modeling assumptions.[37] This was a significant issue in the review of MOPR offer floors in the 2022/2023 BRA.

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36 *See* "PJM Manual 15: Cost Development Guidelines," Rev. 41 (October 1, 2022) § 12.7.

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

The MMU recommends that the RPM market power mitigation rules be modified to apply offer caps in all cases when the three pivotal supplier test is failed and the sell offer is greater than the offer cap in order to ensure that market power does not result in an increase in uplift payments for seasonal products. The RPM rules require that offer caps be applied to all sell offers for Existing Generation Capacity Resources when the capacity market seller fails the three pivotal supplier test, the submitted sell offer exceeds the defined offer cap, and the submitted sell offer, absent mitigation, would result in a higher market clearing price.[38] Under the seasonal capacity rules, the optimization considers the average cost of clearing seasonal offers, including an offer in each season. This can result in clearing seasonal sell offers for the higher cost season at offer prices that are not competitive and making seasonal uplift payments based on those high offer prices.

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

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

The MMU recommends that the market clearing results be used in settlements rather than the reallocation process currently used or that the process of modifying the obligations to pay for capacity be reviewed. 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 PJM improve the clarity and transparency of its CETL calculations. CETL is a critical parameter that can have significant impacts on capacity market outcomes. The changes in CETL that have affected market outcomes in this and prior auctions have not been well explained. CETL analysis has assumed the equivalent of capacity imports in the form of emergency transfers from external balancing authorities when there are no actual capacity imports and when there can be no capacity imports (from the NYISO) but that issue has been resolved. The MMU recommends that CETL be

38 OATT Attachment DD § 6.5.

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

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

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

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.

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

Summary of Results

As shown in Table 16 and Table 17, the 139,399.5 MW of cleared generation and DR for the entire RTO, resulted in a reserve margin of 21.6 percent and a net excess of 7,835.3 MW over the reliability requirement adjusted for FRR and PRD of 131,564.2 MW.[39] [40] Net excess increased 175.1 MW from the net excess of 7,660.2 MW in the 2022/2023 RPM Base Residual Auction. As shown in Figure 2, the intersection of the supply curve and the downward sloping VRR demand curve resulted in a clearing price for Capacity Performance Resources of $34.13 per MW-day.

Table 1 and Table 2 summarize the sensitivity analyses.

The downward sloping shape of the demand curve, the VRR curve, had a significant impact on the auction results. 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 2023/2024 RPM Base Residual Auction were $2,196,444,791. If PJM had used a vertical demand curve set equal to the reliability requirement for the 2023/2024 BRA and everything else had remained the same, total RPM market revenues for the 2023/2024 BRA would have been $1,212,977,260, a decrease of $983,467,530, or 44.8 percent, compared to the actual results. From another perspective, clearing the auction using a downward sloping VRR curve resulted in an 81.1 percent increase in RPM revenues for the 2023/2024 RPM BRA compared to what RPM revenues would have been with a vertical demand curve set equal to the reliability requirement. (Scenario 1)

The downward sloping shape of the VRR curve had a significant impact on the outcome of the auction. As a result of the flatter downward sloping VRR demand curve, more capacity cleared in the market than would have cleared with a steeper demand curve set at half way between the VRR curve used in the 2023/2024 BRA and the vertical demand

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39 The 21.6 percent reserve margin does 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. The 21.6 percent reserve margin also does not include the 196.3 MW of uplift. This is how PJM calculates the reserve margin.

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

curve defined by the reliability requirement. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2023/2024 RPM Base Residual Auction were $2,196,444,791. If PJM had used a VRR curve set at half way between the VRR curve used in the 2023/2024 RPM Base Residual Auction and the reliability requirement for 2023/2024 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2023/2024 RPM Base Residual Auction would have been $1,790,941,751, a decrease of $405,503,039, or 18.5 percent, compared to the actual results. From another perspective, clearing the auction using a downward sloping VRR curve resulted in a 22.6 percent increase in RPM revenues for the 2023/2024 RPM Base Residual Auction compared to what RPM revenues would have been with a VRR curve set at half way between the VRR curve used in the 2023/2024 RPM Base Residual Auction and the reliability requirement. (Scenario 2)

The accuracy of the peak load forecast had a significant impact on the auction results.[41] [42] An analysis of the RPM auctions for the 2017/2018 through 2022/2023 Delivery Years shows that the peak load forecast for the Third Incremental Auction has been on average 3.1 percent lower than the peak load forecast used for the corresponding Base Residual Auction. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2023/2024 RPM Base Residual Auction were $2,196,444,791. If the peak load forecast for the 2023/2024 RPM Base Residual Auction had been 3.1 percent lower and everything else had remained the same, total RPM market revenues for the 2023/2024 RPM Base Residual Auction would have been $1,729,724,427, a decrease of $466,720,364, or 21.2 percent, compared to the actual results. From another perspective, using PJM's peak load forecast for the 2023/2024 Base Residual Auction resulted in a 27.0 percent increase in RPM revenues for the 2023/2024 RPM Base Residual Auction compared to what revenues would have been using a load forecast that is 3.1 percent below the PJM peak load forecast. (Scenario 3)

The decrease in the ComEd CETL of 1,058.0 MW, or 15.5 percent, from the 2022/2023 level to the 2023/2024 level did not have any impact on the auction results. The results of the scenario show that the ComEd price for the 2023/2024 RPM Base Residual Auction would have been the same if the CETL had remained at the higher 2022/2023 CETL value. Based on actual auction clearing prices and quantities and uplift MW, total RPM market

41 PJM has developed its forecasting process. The historical error levels include auctions that were held approximately three years prior to the delivery year while the 2023/2024 BRA was held approximately one year prior to the delivery year.

42 PJM recently hired a consultant to provide advice on its forecasting methods. See PJM Model Review and Recommendations, Itrón, Item 3 in the meeting materials for the Load Analysis Subcommittee, PJM L.L.C., July 28, 2022 <https://pjm.com/committees-and-groups/subcommittees/las>.

revenues for the 2023/2024 RPM Base Residual Auction were $2,196,444,791. If the 2022/2023 CETL value for ComEd had been used in the 2023/2024 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2023/2024 RPM Base Residual Auction would have remained the same. (Scenario 4)

The increase in the MAAC CETL of 2,006.0 MW, or 45.9 percent, from the 2022/2023 level to the 2023/2024 level had a limited impact on the auction results. The results of the scenario show that the MAAC price for the 2023/2024 RPM Base Residual Auction would be higher if the CETL had remained at the lower 2022/2023 CETL value. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2023/2024 RPM Base Residual Auction were $2,196,444,791. If the lower 2022/2023 CETL value for MAAC had been used in the 2023/2024 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2023/2024 RPM Base Residual Auction would have been $2,191,931,381, a decrease of $4,513,409, or 0.2 percent, compared to the actual results.[43] From another perspective, the use of 2023/2024 CETL value for MAAC resulted in a 0.2 percent increase in RPM revenues for the 2023/2024 RPM Base Residual Auction compared to what RPM revenues would have using the 2022/2023 CETL value for MAAC. (Scenario 5)

Overstatement of the reliability contribution of intermittent resources can have a significant impact on capacity market results.[44] The PJM method for computing derated capacity values, applicable to delivery years prior to 2023/2024, and PJM's ELCC method, used to determine capacity values for 2023/2024, incorrectly included generation in excess of the CIR levels for wind and solar generators. As a result, PJM recalculated the ELCC class ratings for 2023/2024 excluding generation from wind and solar resource in excess of CIR levels.[45] The incorrect, rather than the corrected class ratings, were used in the 2023/2024 RPM Base Residual Auction.

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43 This apparently counterintuitive result in aggregate is a result of offsetting changes in LDA revenues.

44 There were no offers for battery resources in the 2023/2024 RPM Base Residual Auction. The 10 hour rule, for determining the capacity value of batteries, was effective for the 2023/2024 RPM Base Residual Auction. Beginning with the 2023/2024 Delivery Year, capacity value for batteries is determined by PJM's ELCC analysis.

45 "Impact on Wind & Solar Class UCAP Values by Capping Hourly Outputs in UCAP Calculation at CIR Level," Item 4A in meeting notes for PC Special Session – CIRs for ELCC Resource, PJM Interconnection LLC, May 19, 2022 <https://pjm.com/committees-and-groups/committees/pc>.

As a sensitivity to calculate that impact of overstating the capacity value of wind and solar generators, the MMU calculated an updated accredited UCAP based on the revised ELCC class ratings for each wind and solar resource. The capacity offer for each wind and solar resource was adjusted to be the lesser of the corrected accredited UCAP and the CIR level. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2023/2024 RPM Base Residual Auction were $2,196,444,791. If the unforced capacity of solar and wind resources offered in the 2023/2024 RPM Base Residual Auction had been capped at the lesser of the corrected accredited UCAP and the CIR level, and everything else had remained the same, total RPM market revenues for the 2023/2024 RPM Base Residual Auction would have been $2,254,726,706, an increase of $58,281,915, or 2.7 percent, compared to the actual results. From another perspective, the inclusion of all offers from solar and wind resources resulted in a 2.6 percent decrease in RPM revenues for the 2023/2024 RPM Base Residual Auction compared to what RPM revenues would have been if offers from solar and wind resources had been limited by the corrected accredited UCAP. (Scenario 6)

The inclusion of all sell offers for demand resources, including annual and seasonal, had a significant impact on the auction results. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2022/2023 RPM Base Residual Auction were $2,196,444,791. If there had been no offers for DR in the 2023/2024 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2023/2024 RPM Base Residual Auction would have been $4,111,765,958, an increase of $1,915,321,168, or 87.2 percent, compared to the actual results. From another perspective, the inclusion of DR resulted in a 46.6 percent reduction in RPM revenues for the 2023/2024 RPM Base Residual Auction compared to what RPM revenues would have been without any DR. (Scenario 7)

The inclusion of sell offers for EE, with the EE addback mechanism, had a significant impact on the auction results. The 2023/2024 RPM Base Residual Auction was the fifth BRA that included EE and the EE addback mechanism. RPM rules allow EE to participate on the supply side. An adjustment is made to the demand curve through the EE addback mechanism to avoid affecting the clearing price, because EE for the delivery year is reflected in the revised load forecast model for the same delivery year. PJM did not require EE addback to equal EE cleared in all auctions prior to 2023/2024 Delivery Year. This flawed EE addback mechanism resulted in more EE addback than EE cleared, distorting the clearing prices. Based on the issue charge introduced by the MMU, PJM updated the EE addback rules effective with the 2023/2024 Delivery Year to ensure that the difference between EE addback and EE cleared is minimized.[46] The combination of EE and the EE

[46] "PJM Manual 18: PJM Capacity Market," § 2.4.5 Adjustments to RPM Auction Parameters for EE Resources, Rev. 54 (Sep. 21, 2022).

addback mechanism had a significant impact on the auction results. The impact of EE and the addback mechanism was a result of customers paying for a significant level of EE MW and a zero impact from the market price increase as a result of the updated EE addback mechanism. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2022/2023 RPM Base Residual Auction were $2,196,444,791. If there were no offers for EE and the EE addback MW were removed in the 2023/2024 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2023/2024 RPM Base Residual Auction would have been $2,114,675,175, a decrease of $81,769,616, or 3.7 percent, compared to the actual results. From another perspective, the inclusion of EE offers and the EE addback MW, resulted in a 3.9 percent increase in RPM revenues for the 2023/2024 RPM Base Residual Auction compared to what RPM revenues would have been if energy efficiency projects were reflected in the demand and EE did not participate on the supply side. (Scenario 8)

The 2023/2024 RPM Base Residual Auction was the third BRA that included submissions for Price Responsive Demand (PRD). The inclusion of PRD had a limited impact on the auction results. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2023/2024 RPM Base Residual Auction were $2,196,444,791. If there had been no submissions from PRD providers in the 2023/2024 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2023/2024 RPM Base Residual Auction would have been $2,206,858,085, an increase of $10,413,294, or 0.5 percent, compared to the actual results. From another perspective, the inclusion of PRD resulted in a 0.5 percent reduction in RPM revenues for the 2023/2024 RPM Base Residual Auction compared to what RPM revenues would have been without any PRD. (Scenario 9)

The 2023/2024 RPM Base Residual Auction was the third BRA held using the seasonal products for summer and winter capacity. The inclusion of seasonal offers (Demand Resources, Energy Efficiency Resources, and Generation Resources) had a significant impact on the auction results. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2023/2024 RPM Base Residual Auction were $2,196,444,791. If there had been no offers for Seasonal products in the 2023/2024 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2023/2024 RPM Base Residual Auction would have been $2,277,928,225, an increase of $81,483,434, or 3.7 percent, compared to the actual results. From another perspective, the inclusion of Seasonal offers resulted in a 3.6 percent decrease in RPM revenues for the 2023/2024 RPM Base Residual Auction compared to what RPM revenues would have been without any Seasonal offers. (Scenario 10)

Matching seasonal offers across LDAs had a limited impact on the auction results. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2023/2024 RPM Base Residual Auction were $2,196,444,791. If seasonal offers were not matched with complementary seasonal offers from other LDAs in the

2023/2024 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues would have been $2,195,770,974, a decrease of $673,816 or less than 0.1 percent, compared to the actual results. From another perspective, allowing the matching of offers from seasonal products across child LDAs in the same parent LDA resulted in a less than 0.1 percent increase in RPM revenues for the 2023/2024 RPM Base Residual Auction compared to what RPM revenues would have been if Seasonal offers were only matched with complementary seasonal offers within the same LDA. (Scenario 11)

The inclusion of capacity imports in the 2023/2024 RPM Base Residual Auction had a significant impact on the auction results. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2023/2024 RPM Base Residual Auction were $2,196,444,791. If offers for external generation had been eliminated and everything else had remained the same, total RPM market revenues for the 2023/2024 RPM Base Residual Auction would have been $2,288,709,765, an increase of $92,264,974, or 4.2 percent, compared to the actual results. From another perspective, the impact of including capacity imports resulted in a 4.0 percent reduction in RPM revenues for the 2024/2023 RPM Base Residual Auction compared to what RPM revenues would have been if no capacity imports were included in the auction. (Scenario 12)

The combined impact of issues related to the definition of capacity had a significant impact on the auction results. Together, the overstatement of intermittent MW offers, and the inclusion of sell offers from demand resources, EE, PRD, seasonal products, and imports had a significant combined impact on the auction results. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2023/2024 RPM Base Residual Auction were $2,196,444,791. If there had been no overstatement of intermittent MW offers and no offers from demand resources, EE, PRD, seasonal products, or imports in the 2023/2024 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2023/2024 RPM Base Residual Auction would have been $4,919,185,790, an increase of $2,722,740,999, or 124.0 percent, compared to the actual results. From another perspective, the inclusion of overstated intermittent MW offers, and offers from demand resources, EE, PRD, seasonal products and imports resulted in a 55.3 percent decrease in RPM revenues for the 2023/2024 RPM Base Residual Auction compared to what RPM revenues would have been without overstated intermittent MW offers, and offers from demand resources, EE, PRD, seasonal products and imports. (Scenario 13)

Nuclear offer behavior in the 2023/2024 RPM Base Residual Auction had no impact on the auction results. Nuclear offer behavior in the 2023/2024 RPM Base Residual Auction was significantly different from that in the 2022/2023 BRA. In both the 2022/2023 BRA and the 2021/2022 BRA a significant level of nuclear capacity was offered at higher sell offer prices than in the 2020/2021 BRA, and fewer nuclear MW cleared in the 2022/2023 BRA and

2021/2022 BRA than in the 2020/2021 RPM BRA. (See Table 22 and Table 23).[47] To define an upper bound on the impact of nuclear offers, a scenario setting all nuclear offers to $0 per MW-day was analyzed. It is not asserted that a $0 per MW-day sell offer is the competitive offer for all nuclear resources. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2023/2024 RPM Base Residual Auction were $2,196,444,791. If all nuclear offers were replaced by $0 per MW-day nuclear offers in the 2023/2024 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2023/2024 RPM Base Residual Auction would have remained the same. (Scenario 14)

The impact of some of the identified market design flaws reduced capacity market prices and the impact of other identified market design flaws increased capacity market prices. The combined impact of the identified market design flaws was to reduce capacity market revenues by 24.3 percent in the 2023/2024 BRA. The identified market design flaws are: the shape of the VRR curve; the overstatement of intermittent MW offers; the inclusion of sell offers from DR; and capacity imports. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2023/2024 RPM Base Residual Auction were $2,196,444,791. If all of the identified market design flaws had been corrected in the 2023/2024 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2023/2024 RPM Base Residual Auction would have been $2,901,559,097, an increase of $705,114,306, or 32.1 percent, compared to the actual results. From another perspective, the identified market design flaws resulted in a 24.3 percent reduction in RPM revenues for the 2023/2024 RPM Base Residual Auction compared to what RPM revenues would have been without those flaws (Scenario 15).

[47] See PJM. Markets and Operations. BRA Reports are organized by Delivery Years and are located at <https://www.pjm.com/markets-and-operations/rpm>. Associated press releases can be found at <https://www.pjm.com/about-pjm/newsroom/announcements-and-news-releases> .

Summary Results Tables

Table 1 Scenario summary for 2023/2024 RPM Base Residual Auction: Impacts on RPM revenue

Scenario	Scenario Description	RPM Revenue ($ per Delivery Year)	Scenario Impact RPM Revenue ($ per Delivery Year)	Scenario Impact Percent
0	Actual Results	$2,196,444,791	NA	NA
1	Downward sloping VRR curve	$1,212,977,260	$983,467,530	81.1%
2	Modified VRR curve	$1,790,941,751	$405,503,039	22.6%
3	Over forecast peak load	$1,729,724,427	$466,720,364	27.0%
4	Change in ComEd CETL	$2,196,444,791	$0	0.0%
5	Change in MAAC CETL	$2,191,931,381	$4,513,409	0.2%
6	Overstated intermittent capacity	$2,254,726,706	($58,281,915)	(2.6%)
7	Demand resources	$4,111,765,958	($1,915,321,168)	(46.6%)
8	EE offers and EE add back	$2,114,675,175	$81,769,616	3.9%
9	PRD	$2,206,858,085	($10,413,294)	(0.5%)
10	Seasonal products	$2,277,928,225	($81,483,434)	(3.6%)
11	Seasonal matching across LDAs	$2,195,770,974	$673,816	0.0%
12	Capacity imports	$2,288,709,765	($92,264,974)	(4.0%)
13	Combined scenarios 6,7,8,9,10,12	$4,919,185,790	($2,722,740,999)	(55.3%)
14	Nuclear offers	$2,196,444,791	$0	0.0%
15	Combined scenarios 2,6,7,12	$2,901,559,097	($705,114,306)	(24.3%)

Table 2 Scenario summary for 2023/2024 RPM Base Residual Auction: Impacts on RPM cleared UCAP MW

Scenario	Scenario Description	Cleared UCAP (MW)	Scenario Impact Cleared UCAP (MW)	Scenario Impact Percent
0	Actual Results	144,870.6	NA	NA
1	Downward sloping VRR curve	131,564.3	13,306.3	10.1%
2	Modified VRR curve	141,119.4	3,751.2	2.7%
3	Over forecast peak load	139,895.0	4,975.6	3.6%
4	Change in ComEd CETL	144,870.6	0.0	0.0%
5	Change in MAAC CETL	145,199.1	(328.5)	(0.2%)
6	Overstated intermittent capacity	144,828.9	41.7	0.0%
7	Demand resources	143,568.3	1,302.2	0.9%
8	EE offers and EE add back	139,399.5	5,471.1	3.9%
9	PRD	145,126.7	(256.1)	(0.2%)
10	Seasonal products	144,526.3	344.3	0.2%
11	Seasonal matching across LDAs	144,814.6	56.0	0.0%
12	Capacity imports	144,768.4	102.2	0.1%
13	Combined scenarios 6,7,8,9,10,12	137,535.0	7,335.6	5.3%
14	Nuclear offers	144,870.6	0.0	0.0%
15	Combined scenarios 2,6,7,12	140,596.2	4,274.4	3.0%

Market Design

Capacity Market Design Changes

Market Seller Offer Cap (MSOC)

In a September 2, 2021, Order in Docket Nos. EL19-47-000, EL19-64-000, ER21-2444-000, and ER21-2877-000, the Commission reestablished a market seller offer cap (MSOC) of net avoidable cost rate (ACR), replacing the Net CONE times B offer cap.[48] The Commission's modified MSOC rules were applied in the 2023/2024 BRA.

Minimum Offer Price Rule (MOPR)

On June 29, 2018, the Commission initiated an FPA section 206 proceeding to address the price suppressive impact of resources receiving out of market support.[49] The Commission issued revised MOPR rules on December 19, 2019.[50] The December 19, 2019 order, and subsequent order on rehearing and clarification, defined state subsidy and expanded the applicability of the MOPR to any new or existing resource that received a state subsidy, and retained the applicability of MOPR to new gas-fired resources.[51] [52] The Commission's resultant modified MOPR rules were applied in the 2022/2023 BRA.[53]

On July 30, 2021, PJM filed tariff changes to effectively eliminate the MOPR while creating a confusing and inefficient administrative process that effectively makes it both

48 176 FERC ¶ 61,137 (September 2, 2021), *order on reh'g*, 178 FERC ¶ 61,121 (2022); *appeal pending*, Vistra Corp. v FERC, Case Nos 21-1214 et al (D.C. Cir).

49 163 FERC ¶ 61,236 (2018) at 5 and 6.

50 169 FERC ¶ 61,239 (2019).

51 Id. at 37 and 67.

52 *Order on Rehearing and Clarification*, 171 FERC ¶ 61,035 (2020).

53 169 FERC ¶ 61,239 (2019), *order denying reh'g*, 171 FERC ¶ 61,035 (2020).

unnecessary and impossible to prove buyer side market power as PJM defined it.[54] [55] [56] On September 29, 2021, PJM's proposed MOPR changes took effect by operation of law.[57] This new MOPR approach was applied to the 2023/2024 BRA.

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.[58]

Net Revenues

On December 22, 2021, in Docket Nos. EL19-58-006 and ER19-1486-003, the Commission issued an order on voluntary remand, reversing its prior determination that PJM should use a forward looking energy and ancillary services (E&AS) revenue offset and directing

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

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

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

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

58 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).

PJM to submit a compliance filing restoring the tariff provisions defining the backward looking E&AS revenue offset.[59]

ELCC

On July 30, 2021, FERC approved new PJM rules for defining the capacity value of intermittent generators, based on an approach to the effective load carrying capability (ELCC) method.[60] The 2023/2024 RPM Base Residual Auction is the first auction to use capacity values that resulted from PJM's application of an ELCC method.

The MMU opposed PJM's 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, among other issues, but does not oppose the ELCC approach in concept and when done correctly for all resources.[61] [62]

Market Design Issues

There are significant market design issues in the capacity market that result in material differences between the prices that result from the existing design and prices that would result from a market design based on market fundamentals including a consistent definition of capacity.

Competitive Offers

Effective for the 2018/2019 and subsequent delivery years through the 2022/2023 BRA, the default offer cap for Capacity Performance Resources was the applicable zonal net Cost of New Entry (CONE) times (B), where B is the average of the Balancing Ratios (B) during the Performance Assessment Intervals in the three consecutive calendar years that

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59 177 FERC ¶ 61,209 (2021); 179 FERC ¶ 61,104 (2022).

60 See 176 FERC ¶ 61,056.

61 In Docket ER21-278-000, *see* Comments and Motions of the Independent Market Monitor for PJM, (November 20, 2020); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, (December 18, 2020); Comments and Motions of the Independent Market Monitor for PJM (March 22, 2021); Answer and motion for Leave to Answer of the Independent Market Monitor for PJM (April 29, 2021)

62 In Docket ER21-2043, *see* Comments of the Independent Market Monitor for PJM (June 22, 2021); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM (July 9, 2021); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM (July 20, 2021);

precede the Base Residual Auction for such delivery year. Effective for the 2023/2024 delivery year, the offer cap is the net avoidable cost (ACR) of a capacity resource.

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

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

Clearing Prices and Offer Caps

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 clearing prices in the 2022/2023 BRA based on actual offers averaged less than half the level of the offer caps. But some generation owners did successfully exercise market power within this design. The change in the MSOC for the 2023/2024 BRA protected the market from noncompetitive outcomes. The clearing prices in the 2023/2024 BRA based on actual offers averaged less than one quarter the level of the offer caps based on Net CONE times B that would have been used absent the MSOC rule change.

Table 3 shows the weighted average clearing prices in the 2022/2023 BRA by zone compared to the corresponding offer cap based on net Cost of New Entry (CONE) times B, where B is the average of the Balancing Ratios during the Performance Assessment Intervals in the three consecutive calendar years that precede the Base Residual Auction for such delivery year. The weighted average clearing prices were less than Net CONE times B for every zone. Of the 22 identified zones, the weighted average clearing price was less than 50 percent of Net CONE times B in 14 zones and less than 60 percent in 20 zones.[63] The weighted average 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.

Table 3 also shows the weighted average clearing prices in the 2023/2024 BRA by zone compared to the corresponding offer cap based on Net CONE times B that would have been used absent the MSOC rule change. The weighted average clearing prices were less than Net CONE times B for every zone. Of the 22 identified zones, the weighted average clearing price was less than 25 percent of Net CONE times B in 19 zones and less than 40 percent in all 22 zones.[64] The weighted average clearing price in BGE Zone was 35.2 of Net CONE times B and the weighted average clearing price in Penelec Zone, where Net CONE was lower than other zones, was 32.2 of Net CONE times B. Overall, the average clearing price was 22.2 percent of the average Net CONE times B.

63 PJM continues to use the prior zone names in the capacity market despite the changes PJM has made to zone names in the energy market.

64 PJM continues to use the prior zone names in the capacity market despite the changes PJM has made to zone names in the energy market.

Table 3 Clearing prices and Net CONE times B: 2022/2023 and 2023/2024 RPM Base Residual Auctions

	2022/2023 BRA				2023/2024 BRA			
Zone	Weighted Average Clearing Price ($ per MW-day)	Net CONE Times B ($ per MW-day)	Clearing Price less Net CONE Times B ($ per MW-day)	Clearing Price to Net CONE Times B	Weighted Average Clearing Price ($ per MW-day)	Net CONE Times B ($ per MW-day)	Clearing Price less Net CONE Times B ($ per MW-day)	Clearing Price to Net CONE Times B
AECO	$97.84	$195.16	($97.32)	50.1%	$49.49	$210.02	($160.53)	23.6%
AEP	$50.00	$167.17	($117.17)	29.9%	$34.13	$172.96	($138.83)	19.7%
AP	$50.00	$149.29	($99.29)	33.5%	$34.13	$148.40	($114.27)	23.0%
ATSI	$50.00	$169.71	($119.71)	29.5%	$34.13	$196.54	($162.41)	17.4%
BGE	$114.02	$166.67	($52.65)	68.4%	$61.75	$175.39	($113.64)	35.2%
ComEd	$69.02	$182.50	($113.48)	37.8%	$34.13	$208.86	($174.73)	16.3%
DAY	$50.00	$166.64	($116.64)	30.0%	$34.13	$194.56	($160.43)	17.5%
DEOK	$71.66	$164.65	($92.99)	43.5%	$34.13	$190.85	($156.72)	17.9%
DLCO	$50.00	$165.18	($115.18)	30.3%	$34.13	$189.65	($155.52)	18.0%
DPL	$97.55	$173.90	($76.35)	56.1%	$55.66	$185.50	($129.84)	30.0%
Dominion	$50.00	$184.14	($134.14)	27.2%	$34.13	$193.74	($159.61)	17.6%
EKPC	$50.00	$168.27	($118.27)	29.7%	$34.13	$190.81	($156.68)	17.9%
External	$50.00	$191.80	($141.80)	26.1%	$34.13	$198.93	($164.80)	17.2%
JCPL	$97.84	$196.28	($98.44)	49.8%	$49.49	$211.10	($161.61)	23.4%
Met-Ed	$95.79	$175.23	($79.44)	54.7%	$49.49	$198.06	($148.57)	25.0%
OVEC	$50.00	$158.91	($108.91)	31.5%	$34.13	$188.03	($153.90)	18.2%
PECO	$97.86	$189.91	($92.05)	51.5%	$49.49	$215.96	($166.47)	22.9%
PENELEC	$95.78	$122.15	($26.37)	78.4%	$49.49	$153.92	($104.43)	32.2%
PPL	$95.78	$184.38	($88.60)	51.9%	$49.49	$206.32	($156.83)	24.0%
PSEG	$97.83	$197.65	($99.82)	49.5%	$49.49	$212.44	($162.95)	23.3%
Pepco	$95.27	$191.09	($95.82)	49.9%	$49.47	$203.05	($153.58)	24.4%
RECO	$97.46	$192.87	($95.41)	50.5%	$49.49	$207.65	($158.16)	23.8%
Average	$76.08	$175.16	($99.08)	43.6%	$42.65	$193.31	($150.66)	22.2%

CP Must Offer Requirement

Prior to the implementation of the capacity performance design, all capacity resources were subject to the must offer requirement. There is no reason to exempt intermittent and capacity storage resources, including hydro, demand resources and energy efficiency resources from the must offer requirement. The same rules should apply to all capacity resources. The purpose of the must offer rule, which has been in place since the beginning of the capacity market in 1999, is to ensure that the capacity market works based on the inclusion of all demand and all supply, and to prevent the exercise of market power via withholding of supply. The failure to apply the must offer requirement will create increasingly significant market design issues and market power issues in the capacity market as the level of capacity from intermittent and storage resources increases and the level of demand side resources remains high. The failure to apply the must offer requirement consistently could also create price volatility and uncertainty in the capacity market and put PJM's reliability margin at risk. The capacity market was designed on the basis of a must buy requirement for load and a corresponding must offer requirement for capacity resources. The capacity market can work only if both are enforced. In the 2023/2024 BRA, 17,037.1 MW were considered categorically exempt from the must offer requirement based on intermittent and capacity storage classification. Some of these resources were offered as capacity in the BRA and as part of FRR plans. The result was that 5,308.3 MW of intermittent and storage resources (3.7 percent of total cleared MW) were not offered in the 2023/2024 BRA. (See Table 8)

The sum of cleared MW that were considered categorically exempt from the must offer requirement is 7,534.3 MW, or 44.4 percent of the required reserves and 30.4 percent of total reserves. The cleared MW of DR is 8,203.3 MW, or 48.4 percent of required reserves and 33.1 percent of total reserves. The sum of cleared MW that were categorically exempt from the must offer requirement and the cleared MW of DR is 15,737.7 MW, or 92.8 percent of required reserves and 63.5 percent of total reserves.

Effective for the 2018/2019 and subsequent delivery years, all capacity resources are subject to the must offer requirement, with the exception of intermittent and storage resources which are categorically exempt from the must offer requirement. Capacity Storage Resources include hydroelectric, flywheel and battery storage. Intermittent Resources include wind, solar, landfill gas, run of river hydroelectric, and other renewable resources. Exceptions to the CP must offer requirement may be requested by demonstrating that the Generation Capacity Resource is physically incapable of satisfying the requirements of a CP Resource. In addition, PJM, considering advice and recommendation from the MMU, may reject eligibility of a resource to offer as CP.[65]

Avoidable Costs

Economics defines avoidable costs as costs that are neither short run marginal costs, like fuel or consumables, nor fixed costs like depreciation and rate of return. The exact dividing line between fixed costs and avoidable costs is established by the tariff as one year. Avoidable costs are the costs that a generation owner incurs as a result of operating a generating unit for one year. Conversely, but less intuitively, the tariff defines avoidable costs as the costs that a generation owner would not incur if the generating unit did not operate for one year. The two definitions produce identical results if applied correctly. Although the term mothball is used in the tariff to modify the term ACR, the term mothball is not defined in the tariff. 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 the different avoidable cost levels. 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.

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65 OATT Attachment DD § 5.5A(a)(i)(B).

Constraints in RPM Markets: CETO/CETL

Since the ability to import energy and capacity in LDAs may be limited by the existing transmission capability, PJM does a load deliverability analysis for each LDA.[66] The first step in this process is to determine the transmission import requirement into an LDA, called the Capacity Emergency Transfer Objective (CETO). This value, expressed in unforced megawatts, is the transmission import capability required for each LDA to meet the area reliability criterion of loss of load expectation of one occurrence in 25 years when the LDA is experiencing a local capacity emergency.

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

If CETL is less than CETO, transmission upgrades are planned under the Regional Transmission Expansion Planning (RTEP) Process. However, if transmission upgrades cannot be built prior to a delivery year to increase the CETL value, the lower level of CETL, in combination with the internal LDA capacity resource supply curve, could result in larger locational price differences than if the CETL target were met.[67]

Under the Tariff, PJM determines, in advance of each BRA, whether specific Locational Deliverability Areas (LDAs) will be modeled in the auction, based on criteria which vary from clear to vague. PJM allows only modeled LDAs to price separate in an auction, regardless of the underlying fundamentals. Effective with the 2012/2013 Delivery Year, an LDA will be modeled as a potentially constrained LDA for a delivery year if the Capacity Emergency Transfer Limit (CETL) is less than 1.15 times the Capacity Emergency Transfer Objective (CETO), such LDA had a locational price adder in one or more of the three immediately preceding BRAs, or such LDA is determined by PJM in a preliminary analysis to be likely to have a locational price adder based on historic offer price levels. The rules also provide that starting with the 2012/2013 Delivery Year, EMAAC, SWMAAC, and MAAC LDAs will be modeled as potentially constrained LDAs regardless

66 "PJM Manual 14B: PJM Region Transmission Planning Process," § C.2.1.2 Locational Deliverability Areas, Rev. 51 (Dec. 15, 2021). Manual 14B indicates that all "electrically cohesive load areas" are tested.

67 "PJM Manual 18: PJM Capacity Market," § 2.2 Role of Load Deliverability in the Reliability Pricing Model, Rev. 54 (Sep. 21, 2022).

of the results of these three tests.[68] In addition, PJM may decide to model an LDA even if it does not qualify under these tests if PJM finds that "such is required to achieve an acceptable level of reliability."[69] A reliability requirement and a Variable Resource Requirement (VRR) curve are established for each modeled LDA.

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

The MMU recommends that PJM improve the clarity and transparency of its CETL calculations. CETL is a critical parameter that can have significant impacts on capacity market outcomes. The changes in CETL that have affected market outcomes in this and prior auctions have not been well explained. Absent a fully nodal capacity market clearing process, the MMU recommends that PJM use a non-nested model with all LDAs modeled including VRR curves for all LDAs. Each LDA requirement should be met with the capacity resources located within the LDA and exchanges from neighboring LDAs up to the transmission limit. LDAs should be allowed to price separate if that is the result of the individual LDA supply curves and the transmission constraints between LDAs. The MMU recommends that PJM implement a nodal capacity market in order to ensure that transmission constraints and locational economic fundamentals are accurately reflected in capacity market prices.

Capacity Value of Intermittent Resources

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. On July 30, 2021, FERC approved new rules in PJM for determining the capacity value of intermittent generators based on the

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68 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.

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

effective load carrying capability (ELCC) method.[70] 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. 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.

Default derating factors and ELCC values have been 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 default derating factors applied to intermittent nameplate capacity prior to the 2023/2024 Delivery Year and the ELCC calculations effective with the 2023/2024 Delivery Year are based on the incorrect assumption that the intermittent resources provide reliable, deliverable output in excess of their CIRs. But that output is not deliverable when needed for reliability because it is in excess of the defined deliverability rights (CIRs) and therefore should not be included in the definition of intermittent capacity.

PJM recalculated the ELCC class ratings for wind and solar resources assuming the generation from an ELCC resource is capped at its CIR level.[71] The revised class rating for onshore wind is 8.0 percent, 46.7 percent lower than the original class rating of 15.0 percent. The revised rating for fixed solar is 33.0 percent, 13.2 percent lower than the original class rating of 38.0 percent. The revised rating for tracking solar is 51.0 percent, 5.6 percent lower than the original class rating of 54.0 percent.

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. It is not clear why PJM allowed this excess capacity to be offered into the 2023/2024 BRA, given that the issue had been clearly identified in

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

71 "Impact on Wind & Solar Class UCAP Values by Capping Hourly Outputs in UCAP Calculation at CIR Level," Item 4A in meeting notes for PC Special Session – CIRs for ELCC Resource, PJM Interconnection LLC, May 19, 2022 <https://pjm.com/committees-and-groups/committees/pc>.

advance.[72] [73] The MMU recommends that intermittent resources, including storage, not be permitted to offer capacity MW based on energy deliveries that exceed the CIRs assigned to such resources. Correctly defined derating factors will be lower than the CIRs required to meet those derating factors.

Seasonal Capacity

Effective for the 2018/2019 and subsequent delivery years, the RPM market design incorporated seasonal capacity resources.[74] [75]

Summer period capacity performance resources may include demand resources, energy efficiency resources, capacity storage resources, intermittent resources, or environmentally limited resources that have an average expected energy output during the summer peak hour periods consistently and measurably greater than their average expected energy output during winter peak hour periods.[76] This tariff language is vague and includes no actual metrics.

Winter period capacity performance resources may include capacity storage resources, intermittent resources, and environmentally limited resources that have an average expected energy output during winter peak hour periods consistently and measurably greater than its average expected energy output during summer peak hour periods.

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

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72 See OATT Attachment DD § 5.5.; RAA Schedule 10.

73 The revised ELCC class ratings were not used to calculate accredited UCAP for the 2023/2024 BRA.

74 158 FERC ¶ 62,220.

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

76 OATT Attachment DD § 5.5A(e)(i).

inject in the summer to meet the annual peak loads that are expected to occur in the summer.

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

RPM rules allow for the matching of complementary seasonal products across LDAs. Capacity market sellers are able to combine intermittent resources, capacity storage resources, demand resources, energy efficiency resources, or environmentally limited resources to create an aggregate resource regardless of physical or electrical proximity. Rules permitting market participants to aggregate resources in the same LDA became effective in the 2020/2021 Delivery Year. But the capacity performance rules permit aggregation across LDAs.[77] The capacity performance rules also permit capacity market sellers to offer standalone summer or winter resources and the auction clearing optimization matches and clears equal quantities of summer and winter resources from different sellers, also across LDAs.

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

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

There is no reason to have such complex rules for combining seasonal products. PJM is a locational market. Any combined seasonal products should be in the same LDA and preferably at the same location, in order for the energy market and capacity market to remain synchronized and reliability metrics correctly calculated.

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77 OATT Attachment DD § 5.12(a).

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

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

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

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

Demand Side Resource Rules

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.[78] 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

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

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 2023/2024 BRA:[79] [80]

- **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 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.[81] The peak period definition for the EE Resource type includes only the period from the hour ending 15:00 through 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.[82]

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

- **Annual Capacity Performance Resources**

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79 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.

80 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.

81 RAA Schedule 6, Section L.

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

- **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.

Energy Efficiency Resource Rules

EE was first included in the capacity market in 2009, in the BRA for the 2012/2013 Delivery Year and in the incremental auctions for the 2011/2012 Delivery Year.[83] [84] EE was included in the capacity market solely based on the fact that PJM load forecasts used in the capacity market at the time did not fully reflect the impacts of EE on the demand for capacity for four years. EE was included in the capacity market based on the explicit rule that any specific EE resource would be removed from the capacity market after four years. Prior to the 2019/2020 Base Residual Auction, EE was incorporated on the supply side of the capacity market for four years, after which they were included in the PJM demand forecast and eliminated from the supply side in order to avoid double counting. The rationale for inclusion of EE as a supply side resource was entirely based on the assertion that EE would not be fully reflected in the PJM demand forecast for four years.

This lag in the inclusion of EE in the load forecast was resolved. PJM updated the peak load forecast method in 2015 to account for energy efficiency.[85] The 2019/2020 Base Residual Auction, run in May 2016, was the first BRA for which EE was reflected in the revised load forecast model without a lag.[86] But when the PJM forecast method changed so that the assumption underlying EE inclusion in the capacity market was no longer correct, PJM failed to take the logical step of removing EE from the capacity market. Instead, PJM implemented the EE addback adjustment through a change to the manuals rather than the tariff. Effective December 17, 2015, an EE addback mechanism and related changes were implemented.[87] The EE addback adjustment was intended to ensure that the continued inclusion of EE did not affect prices, but it did not work as intended. In addition, the EE addback adjustment does not affect the fact that customers continue to have to pay for EE through the capacity market despite the fact that by PJM's own logic,

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83 *2010 State of the Market Report for PJM*, *Volume 2,* Monitoring Analytics, LLC at 378 (March 10, 2011).

84 See PJM Interconnection, L.L.C., Letter Order in Docket No. ER10-366-000 (January 22, 2010).

85 See Revision History (Revision 29) in *PJM Manual 19: Load Forecasting and Analysis (December 5, 2019)*.

86 See PJM. "2016 Load Forecast Report," <http://www.pjm.com/~/media/documents/reports/2016-load-report.ashx> (January 2016).

87 These rule changes were endorsed at the December 17, 2015, meeting of the PJM Markets and Reliability Committee.

EE should not be in the capacity market and customers should not have to pay for it through the capacity market.

PJM's continued inclusion of EE in the capacity market is inconsistent with the Reliability Assurance Agreement (RAA) which states that an Energy Efficiency Resource is a project "designed to achieve a continuous … reduction in electric energy consumption … that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention."[88]

The MMU recommends that Energy Efficiency Resources (EE) not be included in the capacity market because PJM's peak load forecasts now account for EE, unlike the situation when EE was first added to the capacity market. EE should not be part of the capacity market. EE is appropriately and automatically compensated through the markets because it reduces energy and capacity use and therefore customer payments for energy and capacity. EE is appropriately incorporated in PJM forecasts, so the original logic for the inclusion of EE in the capacity market is no longer correct. Direct payments to EE in the capacity market result in overpayment by customers.

If EE remains in the capacity market, the MMU recommended that the implementation of the EE addback mechanism be modified to ensure that market clearing prices are not affected.[89] If EE is not included in the capacity market, there is no reason to have an addback mechanism.

The mechanics of the EE addback mechanism as implemented in the 2022/2023 and prior BRAs did not appropriately adjust for the level of cleared EE. For each BRA, the reliability requirement of the RTO and each LDA is increased by the UCAP value of all EE with accepted measurement and verification plans for the auction.[90] This increase is the EE addback amount. If the initial results of the BRA solution yield a ratio of EE addback MW to cleared EE MW which exceeds a predetermined threshold ratio, the EE addback MW are set equal to the cleared EE MW from the initial solution times the threshold ratio, and

88 RAA Schedule 6 § L.1.

89 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. 54 (Sep. 21, 2022).

90 "PJM Manual 18: PJM Capacity Market," § 2.4.5 Adjustments to RPM Auction Parameters for EE Resources, Rev. 54 (Sep. 21, 2022).

the auction clearing is rerun a second and final time. The threshold ratio is equal to the historic three year average of cleared EE MW in all auctions for a given delivery year divided by the cleared EE MW in the BRA for that delivery year. There is no good basis for this or any threshold. Use of a threshold is not consistent with an appropriate clearing of the Base Residual Auction. This flawed EE addback mechanism resulted in more EE addback than EE cleared, distorting the clearing prices.

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 updated the EE addback rules, such that starting from the 2023/2024 Base Residual Auction, the EE addback MW is iteratively adjusted until the difference between the EE addback and EE cleared is zero for all LDAs or as close to zero as possible.[91]

External Generation Resources/Capacity Imports

The establishment of a pseudo tie is one requirement for an external resource to be eligible to participate in the PJM Capacity Market. Pseudo tied external resources, regardless of their location, are treated as only meeting the reliability requirements of the rest of RTO and not the reliability requirements of any specific locational deliverability area (LDA). All imports offered in the auction from areas external to PJM are modeled as supply in the rest of RTO and not in any specific zonal or subzonal LDA. The fact that pseudo tied external resources cannot be identified as equivalent to resources internal to specific LDAs illustrates a fundamental issue with capacity imports. Capacity imports are not equivalent to, nor substitutes for, internal resources. All internal resources are internal to a specific LDA.[92]

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91 "PJM Manual 18: PJM Capacity Market," § 2.4.5 Adjustments to RPM Auction Parameters for EE Resources, Rev. 54 (Sep. 21, 2022).

92 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).

Generation external to the PJM region is eligible to be offered into an RPM auction if it meets specific requirements.[93] [94] [95]

Effective May 9, 2017, significantly improved pseudo tie requirements for external generation capacity resources were implemented.[96] 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. Pseudo tied resources must also execute a pseudo tie reimbursement agreement that requires reimbursement of PJM's costs associated with performing studies and modifying its models or systems to establish and accommodate a pseudo tie.[97] [98]

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93 See RAA Schedules 9 & 10.

94 "PJM Manual 18: PJM Capacity Market," § 4.2.2 Existing Generation Capacity Resources – External, Rev. 54 (Sep. 21, 2022).

95 "PJM Manual 18: PJM Capacity Market," § 4.6.4 Importing an External Generation Resource, Rev. 54 (Sep. 21, 2022).

96 161 FERC ¶ 61,197 (2017).

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

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

Any party to these agreements has the right to terminate upon forty-two (42) months' notice prior to the commencement of a delivery year, subject to receiving all necessary regulatory approvals. PJM also has the right to terminate such agreements with sixty (60) days' notice for defined reasons including negative impacts on reliability.[99]

The energy from all external generation resources that have an RPM commitment or FRR capacity plan commitment or that are designated as replacement capacity must be offered in the PJM Day-Ahead Energy Market at a MW level equal to their ICAP.[100]

Planned External Generation Capacity Resources are eligible to be offered into an RPM Auction if they meet specific requirements.[101] [102] 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.[103] 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.[104]

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

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

100 OATT Schedule 1 § 1.10.1A.

101 See RAA § 1.69A.

102 "PJM Manual 18: PJM Capacity Market," § 4.2.4 Planned Generation Capacity Resources – External, Rev. 54 (Sep. 21, 2022).

103 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).

104 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).

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.

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

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

The CTR issue implies a broader issue with capacity market clearing and settlements. The capacity market is cleared based on a three year ahead forecast of load and offers of capacity. Payments to capacity resources in the delivery year are based on the capacity market clearing prices and quantities. But payments by customers in the delivery year are not based on market clearing prices and quantities. Payments by customers in each zone are based on the ratio of zonal forecast peak load to the RTO forecast peak load used for the Third Incremental Auction, run six months prior to the delivery year when auctions follow the traditional schedule.[105] The allocation sometimes creates significant differences between the capacity cleared to meet the reliability requirement and the capacity obligation allocated to the customers in a zone. For example, ComEd Zone, which is identical to ComEd LDA cleared 27,932.1 MW including 5,574.0 MW of imports in the 2021/2022 RPM BRA. The ComEd Zone's capacity obligation, immediately after the

[105] See "PJM Manual 18: PJM Capacity Market," § 7.2.3 Final Zonal Unforced Capacity Obligations, Rev. 54 (Sep. 21, 2022).

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.

Market Clearing Model

The nested structure also contributes to an important inefficiency in the clearing of resources. Under the existing nested structure, every resource is eligible to satisfy the reliability requirement of the local LDA where the resource is located but is also eligible to satisfy the reliability requirement of all the higher level parent LDAs to which it belongs. For example, a resource located within the PSEG North LDA can satisfy the reliability requirement of PSEG North, of PSEG, of EMAAC, of MAAC and of the RTO. The problem arises because the LDA demand (VRR) curves are defined such that, in the optimization, any resource that satisfies the reliability requirement of a higher level LDA results in a larger consumer surplus than clearing that resource in a lower level LDA. The goal of the optimization is to maximize consumer surplus. For example, a capacity resource located in the child LDA PSEG North always results in a higher or equal consumer surplus if it clears to meet the parent LDA PSEG's requirement compared to clearing to meet PSEG North's requirement. As a result, the apparently optimal clearing solution would satisfy the parent LDA's requirement while clearing fewer resources to satisfy the child LDA's requirement. In order to ensure that the requirements of child LDAs are satisfied before the requirements of parent LDAs and therefore to ensure local reliability, the nesting based clearing process used by PJM requires iteratively solving a series of optimizations.[106] This clearing process always produces a solution with a lower consumer surplus by satisfying the child LDA's requirement before satisfying parent LDA's requirement. With this iterative solving, the clearing process may also result in implausible outcomes such as lower prices from a reduction in supply. Absent a fully nodal capacity market clearing process, the MMU recommends that PJM use a non-nested model with all LDAs modeled including VRR curves for all LDAs.

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

PJM's market clearing algorithm does not include uplift payments in the objective function, resulting in a less accurate and less efficient result.[107] In RPM auctions, capacity market sellers are allowed to specify a minimum level of unforced capacity for any resource offered into the auction rather than a fully flexible offer. If any such inflexible offers are marginal or close to marginal, PJM's market solution algorithm relaxes the minimum level on those offers and reruns the optimization, allowing those offers to clear below the specified minimum level. Any resource that, as a result, cleared at a MW level below the specified minimum level, is paid uplift for the difference between the cleared MW and the minimum level, at the clearing price.

If the market clears on a nonflexible sell offer segment, a sell offer that specifies a minimum block MW value greater than zero, the capacity market seller will be assigned uplift MW equal to the difference between the sell offer minimum block MW and the sell offer cleared MW quantity if that solution to the market clearing minimizes the cost of satisfying the reliability requirements across the PJM region.[108] The uplift payment for partially cleared resources equals the uplift MW times the clearing price. A more efficient solution could include not selecting a nonflexible segment from a lower priced offer and accepting a higher priced sell offer that does not include a minimum block MW requirement.[109] [110]

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

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107 For more details on these recommendations, see Attachment A.

108 OATT Attachment DD § 5.14(b).

109 OATT Attachment DD § 5.12(a).

110 For more details, see Attachment A.

MMU Review

The MMU reviewed inputs to and results of the 2023/2024 RPM Base Residual Auction:[111]

- Unit Specific Market Seller Offer Caps. Verified that the avoidable costs (ACR), including avoidable fuel availability expenses and risk adders, and opportunity costs used to calculate offer caps were reasonable and properly documented;

- Net Revenues. Calculated historic unit specific net revenue from PJM energy and ancillary service markets for each PJM Generation Capacity Resource for the three year period from 2019 through 2021;[112]

- Minimum Offer Price Rule (MOPR). Reviewed requests for Unit Specific Exceptions;

- Offers of Planned Generation Capacity Resources. Reviewed sell offers for Planned Generation Capacity Resources to determine if consistent with levels specified in Tariff;

- Exported Resources. Verified that Generation Capacity Resources exported from PJM had firm external contracts or made documented and reasonable opportunity cost offers;

- RPM Must Offer Requirement. Reviewed exceptions to the RPM must offer requirement;

- CP Must Offer Requirement. Reviewed exceptions to the CP must offer requirement;

- Maximum EFORd. Verified that the sell offer EFORd levels were less than or equal to the greater of the one-year EFORd or the five-year EFORd for the period ending September 30, 2021, or reviewed requests for alternate maximum EFORds;

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

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111 Unless otherwise specified, all volumes and prices are in terms of unforced capacity (UCAP), which is calculated as installed capacity (ICAP) times (1-EFORd) for generation resources and as ICAP times the Forecast Pool Requirement (FPR) for DR and EE. The EFORd values in this report are the EFORd values used in the 2023/2024 RPM Base Residual Auction.

112 Net revenue values for the 2023/2024 RPM BRA were calculated consistent with the PJM market rules effective at the time. See 178 FERC ¶ 61,122 (2022).

- Clearing Prices. Verified that the auction clearing prices were accurate, based on submitted offers and the Variable Resource Requirement (VRR) curves;[113]

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

Market Power Tests

All participants in the RTO, MAAC, DPL South, and BGE markets failed the TPS test (Table 4).[114] The result was that offer caps were applied to all sell offers for Existing Generation Capacity Resources when the capacity market seller failed the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would have increased the market clearing price. Contrary to the assertions of many, the MMU calculated unit specific ACR based offer caps for only 72 generation resources (7.2 percent) of the 1,003 generation capacity resources offered.[115]

The offer capping process was significantly different than in the prior two base residual auctions. The Commission's order establishing a replacement rate required the use of offer caps equal to net ACR in the 2023/2024 BRA.[116] Market power mitigation was not applied to any Capacity Performance sell offers of generation capacity resources in the 2022/2023 or 2021/2022 RPM Base Residual Auctions as a result of the fact that the Net CONE times B offer cap applied in those auctions exceeded the competitive level.

In applying the three pivotal supplier market structure test, the relevant supply for the RTO market includes all supply from generation resources offered at less than or equal to 150 percent of the RTO clearing price resulting from offer capped offers for all supply.[117] The relevant supply for the constrained LDA markets includes the incremental supply from generation resources inside the constrained LDAs which was offered at a price

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113 Attachment A reviews why the MMU calculation of auction outcomes differs slightly from PJM's calculation of auction outcomes.

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

115 There were additional unit specific MSOC requests not included in these totals that were submitted and later withdrawn.

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

117 Effective November 1, 2009, DR and EE resources are not included in the TPS test. See 129 FERC ¶ 61,081 (2009) at P 31.

higher than the unconstrained clearing price for the parent LDA market and less than or equal to 150 percent of the clearing price for the constrained LDA resulting from offer-capped offers for all supply. The relevant demand consists of the incremental MW needed in the LDA to relieve the constraint and meet the VRR curve for the LDA.

Table 4 presents the results of the TPS test and the one pivotal supplier test. A generation owner or owners are pivotal if the capacity of the owners' generation facilities is needed to meet the demand for capacity. The results of the TPS are measured by the Residual Supply Index (RSI_3). The RSI_x is a general measure that can be used with any number of pivotal suppliers. The TPS test uses three pivotal suppliers. The subscript denotes the number of pivotal suppliers included in the test. If the RSI_x is less than or equal to 1.0, the supply owned by the specific generation owner, or owners, is needed to meet market demand and the generation owners are pivotal suppliers with a significant ability to influence market prices. If the RSI_x is greater than 1.0, the supply of the specific generation owner or owners is not needed to meet market demand and those generation owners have a reduced ability to unilaterally influence market price.[118] If the RSI_x is equal to 0.0, there is only one supplier and that supplier is a monopoly.

Table 4 RSI results: 2023/2024 RPM Base Residual Auction[119]

	$RSI_{1\ 1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
RTO	0.78	0.68	134	134
MAAC	0.78	0.40	11	11
DPL South	0.00	0.00	1	1
BGE	0.00	0.00	1	1

Offer Caps and Offer Floors

The defined Generation Capacity Resource owners were required to submit ACR or opportunity cost data for exports by 120 days prior to the 2023/2024 RPM Base Residual

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

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

Auction.[120] Market power mitigation measures are applied to Existing Generation Capacity Resources such that the sell offer is set equal to the tariff defined offer cap when the capacity market seller fails the market structure test for the auction, the submitted sell offer exceeds the tariff defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price.[121]

Avoidable costs are the costs that a generation owner incurs as a result of operating the generating unit for one year, in particular the delivery year.[122] 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. Avoidable cost-based offer caps are defined to be net of revenues from all other PJM markets and unit specific bilateral contracts and expected bonus performance payments/nonperformance charges. Capacity resource owners could provide ACR data by providing their own unit specific data or, for auctions for delivery years prior to 2020/2021 and auctions held after September 2, 2021, by selecting the default ACR values. The specific components of avoidable costs are defined in the PJM Tariff.[123]

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).[124] AFAE is defined to include avoidable expenses related to fuel availability and delivery. CPQR is available for Capacity Performance Resources. CPQR is defined to be the quantifiable and reasonably supported cost of mitigating the risks of nonperformance associated with submission of an offer.

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

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

[121] OATT Attachment DD § 6.5.

[122] OATT Attachment DD § 6.8(b).

[123] OATT Attachment DD § 6.8(a).

[124] 151 FERC ¶ 61,208.

As shown in Table 5, 1,003 generation resources submitted Capacity Performance offers in the 2023/2024 RPM Base Residual Auction. The MMU calculated offer caps for 712 generation resources that submitted capacity offers. Unit specific ACR based offer caps were calculated for 72 generation resources (7.3 percent). Of the 1,003 generation capacity resources offered, 612 generation resources had default ACR based offer caps, 72 generation resources had unit specific ACR based offer caps, one generation resource had an opportunity cost based offer cap, 17 Planned Generation Capacity Resources had uncapped offers, 27 generation resources had uncapped planned uprates plus default ACR based offer caps for the existing portion of the units, three generation resources had uncapped planned uprates plus price taker status for the existing portion of the units, while the remaining 271 generation resources were price takers.

Market power mitigation measures are applied to capacity resource subject to MOPR such that the sell offer is set equal to the MOPR Floor Offer Price when the submitted sell offer is less than the MOPR Floor Offer Price and an exception was not granted, or the sell offer is set equal to the agreed upon minimum level of sell offer when the sell offer is less than the agreed upon minimum level of sell offer based on a unit specific exception. As shown in Table 6, there were no unit specific exception requests for MOPR under OATT Attachment DD § 5.14(h-2). Of the 12.3 MW offered that were subject to MOPR, 2.7 MW cleared and 9.6 MW did not clear.

The MOPR review process for the 2023/2024 BRA was notably different than for prior auctions. On September 29, 2021, PJM's proposed MOPR changes took effect by operation of law.[125] The MOPR changes modified the MOPR applicability rules and replaced it with an effectively meaningless MOPR screen.[126] The only reason that any capacity resources were subject to MOPR review in the 2023/2024 BRA was that the resources missed the MOPR certification deadline.[127] Because of the timing of the FERC MOPR decision and the RPM data submission process which was already underway, the MMU's MOPR review process under the prior rules was largely completed but ultimately not applied in the 2023/2024 BRA.

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

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

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

Tables for Offer Caps and Offer Floors

Table 5 ACR statistics: 2023/2024 RPM Base Residual Auction

Offer Cap/Mitigation Type	Number of Generation Resources Offered	Percent of Generation Resources Offered
Default ACR	612	61.0%
Unit specific ACR (APIR)	33	3.3%
Unit specific ACR (APIR and CPQR)	9	0.9%
Unit specific ACR (non-APIR)	13	1.3%
Unit specific ACR (non-APIR and CPQR)	17	1.7%
Opportunity cost	1	0.1%
Default ACR and opportunity cost	0	0.0%
Net CONE times B	NA	NA
Uncapped planned uprates and default ACR	27	2.7%
Uncapped planned uprates and opportunity cost	0	0.0%
Uncapped planned uprate and Net CONE times B	NA	NA
Uncapped planned uprates and price taker	3	0.3%
Uncapped planned generation resources	17	1.7%
Existing generation resources as price takers	271	27.0%
Total Generation Capacity Resources offered	1,003	100.0%

Table 6 MOPR statistics: 2023/2024 RPM Base Residual Auction

			ICAP (MW)			UCAP (MW)	
MOPR Type	Calculation Type	Number of Requests	Requested	MMU Agreed	Offered	Offered	Cleared
OATT Attachment DD § 5.14(h-2)	Unit Specific Exception	0	0.0	0.0	0.0	0.0	0.0
OATT Attachment DD § 5.14(h-2)	Default	NA	NA	NA	12.3	12.3	2.7
Total		0	0.0	0.0	12.3	12.3	2.7

Generation Capacity Resource Changes

As shown in Table 5, Capacity Performance offers were submitted for 1,003 generation resources in the 2023/2024 RPM Base Residual Auction, compared to 1,083 generation resources offered in the 2022/2023 RPM Base Residual Auction, a net decrease of 80 generation resources. This was a result of 112 fewer generation resources offered offset by 32 additional generation resources offered.

The 32 additional generation resources offered consisted of 21 new resources (1,883.3 MW), eight resources that were unoffered in the 2022/2023 BRA (20.6 MW), and three resources that were previously entirely FRR committed (1,188.85 MW).[128]

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

The 21 new Generation Capacity Resources consisted of 16 solar resources (400.6 MW) and 6 other (wind, combustion turbines, and combined cycles) resources (1,482.7 MW).[129]

The 112 fewer generation resources offered consisted of 47 deactivated resources (7,937.2 MW), 35 intermittent resources and capacity storage resources not offered (830.7 MW), 25 additional resources fully committed to FRR (1,000.6 MW), and five resources not offered for other reasons (resources excused from offering for reasons other than retirement or proposed generation capacity resources not offered) (1,116.0 MW). Table 7 shows Generation Capacity Resources for which deactivation requests have been submitted which affected supply between the 2022/2023 BRA and the 2023/2024 BRA.

129 Some numbers not reported as a result of PJM confidentiality rules.

Table 7 Generation Capacity Resource deactivations

Resource Name	LDA	ICAP (MW)	Date Deactivation Notice Submitted	Projected or Actual Deactivation Date
ESSEX 9	PSEG North	81.0	02-Mar-22	01-Jun-22
NEWARK BAY	PSEG North	120.2	15-Jul-21	01-Jun-22
MARTINS CREEK CT 1	PPL	18.0	10-Feb-22	01-Jun-23
MARTINS CREEK CT 2	PPL	17.3	10-Feb-22	01-Jun-23
MARTINS CREEK CT 3	PPL	18.0	30-Sep-21	01-Jun-22
MARTINS CREEK CT 4	PPL	17.2	10-Feb-22	01-Jun-23
HARRISBURG 1	PPL	13.4	30-Sep-21	01-Jun-22
HARRISBURG 2	PPL	13.9	30-Sep-21	01-Jun-22
HARRISBURG 3	PPL	13.8	30-Sep-21	01-Jun-22
ALLENTOWN 1	PPL	14.0	30-Sep-21	01-Jun-22
ALLENTOWN 2	PPL	14.0	30-Sep-21	01-Jun-22
ALLENTOWN 3	PPL	14.0	30-Sep-21	01-Jun-22
ALLENTOWN 4	PPL	14.0	30-Sep-21	01-Jun-22
WILLIAMSPORT 1	PPL	13.2	30-Sep-21	01-Apr-22
WILLIAMSPORT 2	PPL	13.4	30-Sep-21	01-Apr-22
JENKINS 1	PPL	13.8	30-Sep-21	01-Apr-22
JENKINS 2	PPL	13.8	30-Sep-21	01-Apr-22
FISHBACH 1	PPL	14.0	30-Sep-21	01-Apr-22
FISHBACH 2	PPL	14.0	30-Sep-21	01-Apr-22
WEST SHORE 1	PPL	14.0	30-Sep-21	01-Apr-22
WEST SHORE 2	PPL	14.0	30-Sep-21	01-Apr-22
LOCKHAVEN 1	PPL	14.0	30-Sep-21	01-Apr-22
GLENDON LF	MAAC	2.5	31-Aug-21	15-Dec-21
PEDRICKTOWN PCLP	EMAAC	112.8	15-Jul-21	01-Jun-22
MORGANTOWN 1	Pepco	610.0	09-Jun-21	31-May-22
MORGANTOWN 2	Pepco	619.0	09-Jun-21	31-May-22
CHAMBERS CCLP	EMAAC	239.9	09-Mar-22	07-Jun-22
LOGAN KCS	EMAAC	219.0	09-Mar-22	31-May-22
PLEASANTVILLE LF	EMAAC	1.3	10-Sep-21	01-Oct-21
INDIAN RIVER 4	DPL South	410.0	29-Jun-21	31-Dec-26
WAUKEGAN COAL 7	ComEd	328.0	29-Jun-21	31-May-22
WAUKEGAN COAL 8	ComEd	354.4	29-Jun-21	31-May-22
WILL COUNTY COAL 4	ComEd	510.0	29-Jun-21	30-Jun-22
STILLMAN VALLEY LF	ComEd	9.3	30-Dec-21	31-Mar-22
ZIMMER 1	DEOK	1,300.0	19-Jul-21	31-May-22
BUCHANCO 1	RTO	40.0	30-Aug-19	01-Jun-23
BUCHANCO 2	RTO	40.0	30-Aug-19	01-Jun-23
PLEASANTS 1-2	RTO	1,278.0	14-Mar-22	01-Jun-23
SAMMIS 5-7	ATSI	1,490.0	14-Mar-22	01-Jun-23
SAMMIS DIESEL	ATSI	13.0	14-Mar-22	01-Jun-23
AVON LAKE 9	ATSI Cleveland	627.1	14-Jul-21	31-Mar-22
AVON LAKE 10	ATSI Cleveland	25.0	14-Jul-21	31-Mar-22
DINWIDDIE DIESEL	RTO	3.0	29-Sep-21	01-Jun-23
WEAKLEY DIESEL	RTO	7.0	29-Sep-21	01-Jun-23
LANIER DIESEL	RTO	7.0	29-Sep-21	01-Jun-23
ROCKVILLE DIESEL	RTO	3.9	29-Sep-21	01-Jun-23
CHESWICK 1	RTO	565.0	14-Jul-21	31-Mar-22
Total		9,308.2		

RTO Market Results

Total Offers

Table 8 shows total RTO offer data for the 2023/2024 RPM Base Residual Auction. All MW values stated in the RTO section include all nested LDAs.[130] [131] As shown in Table 8, total internal RTO unforced capacity (UCAP), excluding generation winter capacity, decreased 2,804.1 MW (1.4 percent) from 201,302.3 MW in the 2022/2023 RPM BRA to 198,498.2 MW.[132]

When comparing UCAP MW levels from one auction to another, two variables, capacity modifications and EFORd changes, need to be considered. The net internal capacity change attributable to capacity modifications can be determined by holding the EFORd level constant at the prior auction's level. The EFORd effect is the measure of the net internal capacity change attributable to EFORd changes and not capacity modifications. As shown in Table 10, the 2,804.1 MW decrease in internal capacity was a result of net generation capacity modifications (cap mods) (-2,297.4 MW), net DR capacity changes (372.5 MW), net EE modifications (373.3 MW), the EFORd effect due to higher sell offer EFORds (-1,305.4 MW), and the DR and EE effect due to a higher Load Management UCAP conversion factor (52.9 MW).[133]

As shown in Table 12, total internal RTO unforced winter capacity for November through April increased 15.4 MW from 1,918.5 MW in the 2022/2023 BRA to 1,933.9 MW in the

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

131 Maps of the LDAs can be found in the *2021 State of the Market Report for PJM,* Vol. 2, Section 5, Figures 5-5, 5-6, and 5-7.

132 The capacity includes FRR capacity.

133 Prior to the 2018/2019 Delivery Year, the UCAP value of a load management product is equal to the ICAP value multiplied by the Demand Resource (DR) Factor and the Forecast Pool Requirement (FPR). Effective for the 2018/2019 and subsequent delivery years, the UCAP value of a load management product is equal to the ICAP value multiplied by the FPR. For the 2022/2023 BRA, this conversion factor was 1.0868. For the 2023/2024 BRA, this conversion factor was 1.0901. The DR Factor was designed to reflect the difference in losses that occur on the distribution system between the meter where demand is measured and the transmission system. The FPR multiplier is designed to recognize the fact that when demand is reduced by one MW, the system does not need to procure that MW or the associated reserve. See RAA Schedule 6, Section B. See also "PJM Manual 20: PJM Resource Adequacy Analysis," § 1.3 Parameters Reviewed in the Stakeholder Process, Rev. 12 (Aug. 25, 2021).

2023/2024 BRA. The 15.4 MW increase in winter capacity was a result of net generation winter capacity modifications (15.4 MW).

The net generation capacity modifications reflect new and reactivated generation, deactivations, and cap mods to existing generation. Total internal RTO unforced capacity includes all Generation Capacity Resources, Demand Resources, and Energy Efficiency Resources that qualified as PJM Capacity Resources for the 2023/2024 RPM Base Residual Auction, excluding external units, and also includes owners' modifications to installed capacity (ICAP) ratings which are permitted under the RAA and associated manuals.[134] The ICAP of a unit may only be reduced through a cap mod if the capacity owner does not intend to restore the reduced capability by the end of the planning period following the planning period in question.[135] Otherwise the owner must take an outage, as appropriate, if the owner cannot provide energy consistent with the ICAP of the unit. Capacity modifications, DR plan changes, and EE plan changes were the result of owner reevaluation of the capabilities of their generation, DR and EE, at least partially in response to the incentives and penalties contained in RPM as modified by CP changes.

After accounting for generation winter capacity (961.7 MW), for FRR committed resources (31,828.0 MW) and for imports (1,528.0 MW), total RPM capacity was 169,159.9 MW compared to 172,476.1 MW in the 2022/2023 RPM Base Residual Auction.[136] Generation winter capacity increased by 10.3 MW, FRR volumes increased by 492.4 MW, and imports decreased by 30.0 MW from the 2022/2023 RPM Base Residual Auction.[137]

Of the 1,528.0 MW of imports, 0.0 MW were committed to an FRR capacity plan and 1,528.0 MW were offered in the auction, of which 1,396.6 MW cleared. Of the cleared imports, 836.5 MW (59.9 percent) were from MISO.

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134 See RAA Schedule 9.

135 "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," § 2.1 Net Capability - General, Rev. 16 (Aug 1, 2021). The manual states "the end of the next Delivery Year."

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

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

RPM capacity was reduced by exports of 2,517.9 MW, an increase of 1,015.1 MW from the 2022/2023 RPM Base Residual Auction. Of total exports, 1,557.6 MW (61.9 percent) were to MISO, 674.0 MW (26.8 percent) were to NYISO, 95.0 MW (3.8 percent) were to Duke Energy Carolinas, and 191.3 MW (7.6 percent) were to Louisville Gas and Electric Company (LG&E)/Kentucky Utilities Company (KU).

RPM capacity was also reduced by 1,078.5 MW of FRR optional volumes not offered and by 2,639.3 MW which were excused from the RPM must offer requirement.[138] FRR optional volumes increased by 919.4 MW and excused Existing Generation Capacity Resources increased by 1,988.0 MW from the 2022/2023 RPM Base Residual Auction. The excused Existing Generation Capacity Resources were the result of plans for retirement.[139]

In addition, RPM capacity was reduced by 149.3 MW of Planned Generation Capacity Resources which were not subject to the must offer requirement, by 3,720.9 MW of intermittent resources and 1,051.3 MW of capacity storage resources which were not subject to the must offer requirement, by 536.2 MW of unoffered generation winter capacity, and by 1,422.4 MW of unoffered DR and EE.[140] Unoffered Planned Generation Capacity Resources decreased by 86.8 MW, unoffered intermittent resources increased by 2,149.3 MW, unoffered capacity storage resources increased by 440.8 MW, unoffered generation winter capacity increased by 290.1 MW, and unoffered DR and EE increased by 580.2 MW from the 2022/2023 RPM Base Residual Auction.

Subtracting excused and unoffered capacity resulted in 156,044.0 MW that were available to be offered in the RPM Auction, a decrease of 10,612.3 MW from the 2022/2023 RPM Base Residual Auction. After accounting for these factors, 0.0 MW were not offered and unexcused in the RPM Auction.

Offered MW decreased 10,612.3 MW from 166,656.3 MW to 156,044.0 MW, while the overall RTO Reliability Requirement adjusted for FRR obligations, from which the demand curve is developed, decreased 436.2 MW from 132,256.6 MW in the 2022/2023

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

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

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

RPM Base Residual Auction to 131,820.4 MW.[141] The RTO Reliability Requirement adjusted for FRR obligations is calculated as the RTO forecast peak load times the Forecast Pool Requirement (FPR), less FRR UCAP obligations. The FPR is calculated as (1+Installed Reserve Margin) times (1-Pool Wide Average EFORd), where the Installed Reserve Margin (IRM) is the level of installed capacity needed to maintain an acceptable level of reliability.[142] The 436.2 MW decrease in the RTO Reliability Requirement adjusted for FRR obligations from the 2022/2023 RPM Base Residual Auction was a result of a 102.7 MW decrease in the RTO Reliability Requirement not adjusted for FRR and a 333.5 MW increase in the FRR obligation, shifting the RTO market demand curve to the left. The forecast peak load expressed in terms of installed capacity decreased 549.0 MW from the 2022/2023 RPM Base Residual Auction to 149,680.0 MW. The 102.7 MW decrease in the RTO Reliability Requirement was a result of a 596.7 MW decrease in the forecast peak load in UCAP terms holding the FPR constant at the 2022/2023 level offset by a 494.0 MW increase attributable to the change in the FPR. The increase in the FPR from the 2022/2023 RPM Base Residual Auction was a result of an increase in the IRM and a decrease in the pool wide average EFORd.

Table 13 shows the installed and offered generation capacity for the top five owners. The total installed capacity (192,203.9 MW) includes all Generation Capacity Resources that qualified as PJM Capacity Resources for the 2023/2024 RPM Base Residual Auction (189,641.0 ICAP MW), annual equivalent MW quantity for generation winter capacity (961.7 ICAP MW), and external resources offered or committed to an FRR plan (1,601.2 ICAP MW).

Clearing Prices

Table 15 shows the clearing prices for 2022/2023 BRA and 2023/2024 BRA. The clearing price for the RTO decreased by $15.87 or 46.5 percent from $50.00 in the 2022/2023 BRA to $34.13 in the 2023/2024 BRA. The lower clearing prices in 2023/2024 BRA were the combined result of lower offer prices, higher CETL limits, lower gross CONE values, subsidies to select generation resources, and slightly reduced demand. The lower offer prices reflected the significant change in the energy market fundamentals. Competitive capacity market offers reflect, regardless of tariff requirements, participants' forward

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

142 RAA Schedule 4.1.

looking expectations of profits from the energy market and therefore the revenue they require from the capacity market. The spark spread is a measure of the difference between the energy price and the cost of gas required to generate the energy at a defined heat rate. The forward looking peak hour spark spread in the period prior to the 2023/2024 BRA was about 134 percent higher than the forward looking peak hour spark spread in the period prior to the 2022/2023 BRA.

The Commission required the use of historical net revenues in calculating offer caps for the 2023/2024 BRA while forward net revenues were used for the 2022/2023 BRA. The net revenues were not relevant for most units for the 2022/2023 BRA because the inflated offer caps in that auction were based on Net CONE times B. But a comparison of forward net revenues for the 2022/2023 BRA to the historical net revenues for the 2023/2024 BRA shows that even the net revenue based on the lower forwards for the 2022/2023 BRA were higher than the historical net revenues used for the 2023/2024 BRA for about 65 percent of all capacity resources that offered in the 2022/2023 BRA.

Composition of the Steeply Sloped Portion of the Supply Curve

Table 25 shows the composition of the offers on the steeply sloped portion of the total RTO supply curve from $35.00 per MW-day. Overall, total offers greater than $35 per MW-day declined 67 percent, from 55,736.2 MW in the 2022/2023 BRA to 18,293.1 MW in the 2023/2024 BRA. Offers for DR were 13.3 percent of the offers greater than $35.00 per MW-day compared to 6.0 percent in the 2022/2023 RPM Base Residual Auction. Offers for coal fired units made up 50.9 percent of the offers greater than $35.00 per MW-day compared to 32.1 percent in the 2022/2023 RPM Base Residual Auction. Offers for nuclear units made up 0.0 percent of the offers greater than $35.00 per MW-day compared to 21.5 percent in the 2022/2023 RPM Base Residual Auction.

Demand Side Resources

Table 34 shows offered and cleared capacity from DR and EE in the 2023/2024 RPM Base Residual Auction compared to the 2022/2023 RPM Base Residual Auction. Offers for DR decreased from 10,411.4 MW in the 2022/2023 BRA to 10,135.7 MW in the 2023/2024 BRA, a decrease of 275.7 MW or 2.6 percent. Offers for EE increased from 4,933.2 MW in the 2022/2023 BRA to 5,346.8 MW in the 2023/2024 BRA, an increase of 413.6 MW or 8.4 percent.

Capacity Imports

Table 40 shows the MW quantity of imports offered and cleared in the 2007/2008 through 2023/2024 RPM Base Residual Auctions. The highest level of offered (7,493.7 MW) and cleared (7,482.7 MW) imports occurred in the 2016/2017 RPM BRA, which was prior to the implementation of the CIL rules and prior to the implementation of the pseudo tie rules. Of the 1,528.0 MW of imports offered in the 2023/2024 RPM BRA, 1,396.6 MW (91.4 percent) cleared.

CETO/CETL Values

Table 26 shows the CETL and CETO values used in the 2023/2024 study compared to the 2022/2023 values. The CETL values for the MAAC and ComEd LDAs changed significantly. The increase in the MAAC CETL is "primarily attributable to the deactivation of the Morgantown generating units for which deactivation notifications were submitted in June of 2021 with a requested deactivation date of May 2022."[143] The decrease in the ComEd CETL is "primarily attributable to the deactivation of the Waukegan and Will County generating units for which deactivation notifications were submitted in June of 2021 with requested deactivation dates of May 2022 for the Waukegan and Will County units."

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

The Price Impacts of Constraints in the RPM Market

As is the case in locational energy markets, transmission constraints in the PJM capacity markets affect clearing prices both by increasing prices in constrained areas and decreasing prices in unconstrained areas. Conversely, removing constraints reduces prices in constrained areas and increases prices in unconstrained areas. The impact of

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143 See PJM "2023/2024 RPM Base Residual Auction Planning Period Parameters," at pp. 3-4 <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2023-2024/2023-2024-planning-period-parameters-for-base-residual-auction-pdf.ashx> (Feb.28, 2022).

144 See "PJM Manual 14B: PJM Region Transmission Planning Process," § C.3.1.3 General Procedures and Assumptions, Rev. 51 (Dec 15, 2021).

transmission constraints on price separation and on total market revenues depends on the shapes of the supply and demand curves in LDAs.

There were three locationally binding constraints in the 2023/2024 BRA which resulted in demand clearing in a locationally constrained LDA which did not clear in the RTO market or in contiguous or parent LDAs, and which cleared at a higher price than in contiguous or parent LDAs. The result was to shift the demand curve in the RTO market to the left along the upwardly sloping supply curve and to reduce the price in the RTO market. The price impact is the result both of the size of the shift of the demand curve and the slope of the supply curve. The larger the shift in the demand curve and the steeper the slope of the supply curve, the greater the price impact.[145]

Nested LDAs occur when a constrained LDA is a subset of a larger constrained LDA or the RTO. The supply and demand curves for nested LDAs can be presented in two ways to illustrate the market clearing dynamic. The supply curves in the figures in this report, unless otherwise noted, show the total internal supply of the LDA, including all nested LDAs and not including CETL MW. The demand curve is reduced by the CETL and by the MW that cleared incrementally in the constrained, nested LDAs.

Clearing Results

The net load price that load serving entities (LSEs) will pay is equal to the final zonal capacity price less the final Capacity Transfer Rights (CTR) credit rate.[146] As shown in Table 14, the preliminary net load price is $34.20 per MW-day in the RTO. Although EMAAC did not have a binding CETL constraint or price separate in the auction, it does have a separate net load price due to the adjustment to cover funding for PRD credits.[147] Similarly, the adjusted preliminary zonal capacity price of BGE was higher than the preliminary zonal capacity price due to the adjustment to cover the funding for PRD credits.

As shown in Table 16 and Table 17, the 139,399.5 MW of cleared generation and DR for the entire RTO, resulted in a reserve margin of 21.6 percent and a net excess of 7,835.3 MW

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

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

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

over the reliability requirement adjusted for FRR and PRD of 131,564.2 MW (Installed Reserve Margin (IRM) of 14.8 percent).[148] [149] [150] [151] Net excess increased 175.1 MW from the net excess of 7,660.2 MW in the 2022/2023 RPM Base Residual Auction. As shown in Figure 2, the downward sloping VRR demand curve resulted in a clearing price for Capacity Performance Resources of $34.13 per MW-day.

The actual market results in the 2023/2024 BRA did include uplift MW and payments resulting from partially cleared resources. PJM does not include the uplift MW in the calculation of cleared capacity and therefore are not included in the calculation of reserves and excess reserves. Uplift MW should be included in the calculation of cleared capacity and therefore are not included in the calculation of reserves and excess reserves.

Uplift MW and payments can also occur for resources electing the New Entry Price Adjustment (NEPA) or Multi-Year Pricing Option.[152] [153] If an offer clears in an auction under either option and if a qualifying resource does not clear in the two subsequent BRAs, the process specified in the Tariff is triggered, and the resource is awarded an uplift

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

[149] The IRM increased from 14.5 percent in the 2022/2023 RPM Base Residual Auction to 14.8 percent in the 2023/2024 RPM Base Residual Auction.

[150] The 21.6 percent reserve margin does 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. The 21.6 percent reserve margin also does not include the 196.3 MW of uplift. This is how PJM calculates the reserve margin.

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

[152] OATT Attachment DD § 5.14(c)(2).

[153] OATT Attachment DD § 6.8(a).

payment.[154] The market results in the 2023/2024 BRA did not include make whole MW or payments related to NEPA or Multi-Year Pricing Option.

The market results in the 2023/2024 BRA did not include seasonal uplift MW and payments. Under the seasonal capacity rules, the optimization considers the average cost of clearing seasonal offers, including an offer in each season. This can result in clearing seasonal sell offers for the higher cost season at offer prices that are not competitive and making seasonal uplift payments based on those high offer prices.

Table 18 shows offered and cleared MW by LDA, resource type, and season in the 2023/2024 RPM Base Residual Auction. Of the 140,561.5 MW of generation offers, 139,803.4 MW were for the annual season. Of the 10,135.7 MW of DR offers, 9,939.6 MW were for the annual season. Of the 5,346.8 MW of EE offers, 5,221.1 MW were for the annual season.

Table 19 shows the weighted average sell offer prices by LDA, resource type, and season. For generation, the weighted average sell offer prices for generation in RTO for annual were greater than the weighted average sell offer prices for winter, which were greater than the weighted average sell offer prices for summer.

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

Table 20 shows the offered MW by generation capacity resources, season, and price range relative to the applicable market seller offer caps (MSOCs) in the 2023/2024 RPM Base Residual Auction. Of the 140,561.5 MW of generation offers, 58,918.0 MW (41.9 percent) were offered below the applicable MSOC, 80,608.4 MW (57.3 percent) were offered at the applicable MSOC, and 1,035.1 MW (0.7 percent) were offered greater than the applicable MSOC.

Table 21 shows the weighted average sell offer prices and market seller offer caps for existing generation capacity resources in the entire RTO. The weighted average sell offer for existing generation capacity resources was less than half the weighted average market seller offer cap.

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

Table 22 shows cleared MW by zone and fuel source. Of the 140,561.5 MW offered for generation resources, 131,408.6 MW cleared (93.5 percent). Of the 144,870.6 cleared MW in the entire RTO, 25,368.9 MW (17.5 percent) cleared in ComEd, followed by 19,452.3 MW (13.4 percent) in AEP and 14,352.7 MW (9.9 percent) in PPL. Of the 131,408.6 cleared MW for generation resources in the entire RTO, 72,916.9 MW (55.5 percent) were gas resources, followed by 26,365.1 MW (20.1 percent) from nuclear resources and 20,901.3 MW (15.9 percent) from coal resources. Cleared MW from coal resources decreased 5,698.8 MW from the 2022/2023 RPM Base Residual Auction while cleared MW from nuclear resources increased 5,314.8 MW from the 2022/2023 RPM Base Residual Auction.

The 8,956.6 MW uncleared MW in the entire RTO were the result of offer prices which exceeded the clearing prices. Of the 8,956.6 uncleared MW in the entire RTO, 0.0 MW were EE offers, 2,020.5 MW were DR offers, and the remaining 8,956.6 MW were generation offers.[155] Table 23 presents details on the generation offers that did not clear. Of the 8,956.6 MW of uncleared generation offers, 6,358.6 MW (71.0 percent) were for generation resources greater than 40 years old, and 2,598.0 MW (29.0 percent) were for generation resources less than or equal to 40 years old.

Table 24 shows the auction results for the prior two delivery years for the generation resources that did not clear some or all MW in the 2023/2024 BRA. Of the 96 generation resources that did not clear 8,956.6 MW in the 2023/2024 BRA, 52 of those generation resources did not clear 1,423.8 MW in RPM Auctions for the 2022/2023 Delivery Year. Of those 52 generation resources that did not clear MW in RPM Auctions for the 2023/2024 and 2022/2023 Delivery Years, 34 of those generation resources did not clear 197.1 MW in RPM Auctions for the 2020/2021 Delivery Year. Thus, 1,423.8 MW of capacity did not clear in two sequential auctions, but 197.1 MW did not clear in three sequential auctions.

CTRs

For LDAs in which the RPM auctions for a delivery year resulted in a positive locational price adder, an LSE with load in the LDA is entitled to a payment equal to the locational price adder multiplied by the MW of the LSEs' CTRs.[156] [157]

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155 Reported uncleared MW values are based on rounded annual equivalent MW values for seasonal offers.

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

157 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.

At the time of clearing the 2023/2024 RPM Base Residual Auction, DPL had -15.5 MW of CTRs with a total value of -$34,086 and BGE had 4,644.8 MW of CTRs with a total value of $34,782,061. The value of the CTRs will be redefined prior to the delivery year.

MAAC had 1,182.2 MW of customer funded ICTRs with a total value of $6,645,843 and BGE had 65.7 MW of customer funded ICTRs with a total value of $491,985.

MAAC had 560.3 MW of ICTRs due to Incremental Rights-Eligible Required Transmission Enhancements with a value of $3,150,053 and BGE had 306.0 MW with a value of $2,291,438.

Analysis of Market Results

The MMU analyzed the impacts of specific market design features, definitions of capacity, and market behavior. The market design features analyzed are: the shape of the VRR curve; forecast error; and ComEd and MAAC CETL changes. The definitions of capacity analyzed are: intermittent resources; DR; EE; PRD; seasonal products; and imports. The market behavior analyzed is: nuclear plant offers.

Impact of Market Design Issues

The MMU analyzed the impact of specific, significant market design issues, including: the impact of the shape of the demand (VRR) curve; the impact of the load forecast; and the impact of changes in CETL.

Impact of Downward Sloping VRR Curve (Scenario 1)

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.[158] Figure 1 shows the shape of the VRR curve compared to a vertical demand curve at the reliability requirement for the 2023/2024 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

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

margin providing additional reliability benefit at a declining rate, although the basis for the asserted value was not clearly defined based on market fundamentals.[159]

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.[160] PJM defines the reliability requirement as the capacity needed to satisfy the one event in ten years loss of load expectation (LOLE) for the RTO and capacity needed to satisfy the one event in 25 years loss of load expectation for the each LDA. The maximum price on the VRR curve is the greater of Gross CONE or 1.5 times Net CONE for all unforced capacity MW between 0 and 99 percent of the reliability requirement. The first downward sloping segment is from 99 percent and 101.7 percent of the reliability requirement. The second downward sloping segment is from 101.7 percent and 106.8 percent of the reliability requirement (Figure 1).

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

The downward sloping shape of the demand curve, the VRR curve, had a significant impact on the outcome of the auction. 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.

Table 27 shows the results if PJM had used a vertical demand curve set equal to the reliability requirement for RTO and for each modeled LDA in the 2023/2024 RPM Base

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159 See 117 FERC ¶ 61,331 (2006).

160 "Third Triennial Review of PJM's Variable Resource Requirement Curve," The Brattle Group, May 15, 2014, <http://www.pjm.com//media/library/reports-notices/reliability-pricing-model/20140515-brattle-2014-pjm-vrr-curvereport.ashx?la=en>.

Residual Auction and everything else had remained the same. All binding constraints would have remained binding except that the DPL South import limit would not have been binding. The RTO clearing price would have decreased to $16.00 per MW-day, and the clearing quantity would have decreased to 131,564.3 MW. The clearing quantity of seasonal capacity would have would have remained the same at 474.1 MW. The MAAC clearing price would have decreased to $35.79 per MW-day, and the clearing quantity would have decreased to 57,181.9 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have remained the same at 29.3 MW. The DPL South clearing price would have decreased to $35.79 per MW-day, and the clearing quantity would have decreased to 1,235.6 MW. The clearing quantity of seasonal capacity for satisfying DPL South's reliability requirement would have remained the same at 0 MW. The BGE clearing price would have decreased to $69.90 per MW-day, and the clearing quantity would have decreased to 1,812.2 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW.

Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2023/2024 RPM Base Residual Auction were $2,196,444,791. If PJM had used a vertical demand curve set equal to the reliability requirement for 2023/2024 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2023/2024 RPM Base Residual Auction would have been $1,212,977,260, a decrease of $983,467,530, or 44.8 percent, compared to the actual results. From another perspective, clearing the auction using a downward sloping VRR curve resulted in a 81.1 percent increase in RPM revenues for the 2023/2024 RPM Base Residual Auction compared to what RPM revenues would have been with a vertical demand curve set equal to the reliability requirement.

Impact of Modified VRR Curve (Scenario 2)

The MMU proposed changing the parameters of the VRR curve to lower the excessive procurement of capacity above the reliability requirement. For the MMU's proposed VRR curve, the maximum price on the VRR curve is set at greater of Gross CONE or 1.5 times Net CONE for all unforced capacity MW between 0 and 99 percent of the reliability requirement. The first downward sloping segment is set from 99 percent and 100.8 percent of the reliability requirement. The second downward sloping segment is set from 100.8 percent and 103.4 percent of the reliability requirement. The MMU's proposed VRR curve falls half way between the VRR curve used in the 2023/2024 RPM Base Residual Auction and the reliability requirement.

The flatter downward sloping shape of the VRR curve had a significant impact on the outcome of the auction. As a result of the flatter downward sloping VRR demand curve, more capacity cleared in the market than would have cleared with a steeper demand curve set at half way between the VRR curve used in the 2023/2024 BRA and the reliability requirement.

Table 28 shows the results if PJM had used a VRR curve set at half way between the VRR curve used in the 2023/2024 RPM Base Residual Auction and the reliability requirement for RTO and for each modeled LDA in the 2023/2024 RPM Base Residual Auction and everything else had remained the same. All binding constraints would have remained binding except that the DPL South import limit would not have been binding. The RTO clearing price would have decreased to $24.00 per MW-day, and the clearing quantity would have decreased to 141,119.3 MW. The clearing quantity of seasonal capacity would have would have remained the same at 474.1 MW. The MAAC clearing price would have decreased to $47.39 per MW-day, and the clearing quantity would have decreased to 61,171.4 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have remained the same at 29.3 MW. The DPL South clearing price would have decreased to $47.39 per MW-day, and the clearing quantity would have decreased to 1,257.8 MW. The clearing quantity of seasonal capacity for satisfying DPL South's reliability requirement would have remained the same at 0 MW. The BGE clearing price would have remained the same at $69.95 per MW-day, and the clearing quantity would have decreased to 2,242.5 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW.

Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2023/2024 RPM Base Residual Auction were $2,196,444,791. If PJM had used a VRR curve set at half way between the VRR curve used in the 2023/2024 RPM Base Residual Auction and the reliability requirement for 2023/2024 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2023/2024 RPM Base Residual Auction would have been $1,790,941,751, a decrease of $405,503,039, or 18.5 percent, compared to the actual results. From another perspective, clearing the auction using a downward sloping VRR curve resulted in a 22.6 percent increase in RPM revenues for the 2023/2024 RPM Base Residual Auction compared to what RPM revenues would have been with a VRR curve set at half way between the VRR curve used in the 2023/2024 RPM Base Residual Auction and the reliability requirement.

Impact of the Over Forecast Peak Load (Scenario 3)

The accuracy of the peak load forecast had a significant impact on auction results. Table 29 summarizes the peak load forecasts for delivery years 2018/2019 through 2022/2023. The peak load forecast for the Third IA has historically been lower than the peak load forecast used in the corresponding BRA. The Third IA is the last auction prior to the beginning of the delivery year, and the peak load forecast for the Third IA provides the best indicator of the capacity needed to meet the reliability criterion in the delivery year. Analysis of the RPM auctions for the five delivery years from 2018/2019 through 2022/2023 shows that the peak load forecast for the Third Incremental Auction has been on average 3.1 percent lower than the peak load forecast for the corresponding Base Residual Auction.

Table 30 shows the results if the peak load forecast had been 3.1 percent lower in the 2023/2024 RPM Base Residual Auction and everything else had remained the same. All binding constraints would have remained binding except that the DPL South constraint would not be binding under the scenario assumptions. The RTO clearing price would have decreased to $22.00 per MW-day, and the clearing quantity would have decreased to 139,895.0 MW. The amount of cleared seasonal capacity would have remained the same at 474.1 MW. The MAAC clearing price would have decreased to $47.29 per MW-day, and the clearing quantity would have decreased to 60,874.9 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have remained the same at 29.3 MW. The DPL South clearing price would have decreased to $47.29 per MW-day, and the clearing quantity would have decreased to 1,257.8 MW. The clearing quantity for seasonal capacity for satisfying DPL South's reliability requirement would have remained the same at 0 MW. The BGE clearing price would have increased to $97.54 per MW-day, and the clearing quantity would have decreased to 2,109.3 MW. The clearing quantity for seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW.

Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2023/2024 RPM Base Residual Auction were $2,196,444,791. If the peak load forecast for the 2023/2024 RPM Base Residual Auction had been 3.1 percent lower and everything else had remained the same, total RPM market revenues for the 2023/2024 RPM Base Residual Auction would have been $1,729,724,427, a decrease of $466,720,364, or 21.2 percent, compared to the actual results. From another perspective, using PJM's peak load forecast for the 2023/2024 Base Residual Auction resulted in a 27.0 percent increase in RPM revenues for the 2023/2024 RPM Base Residual Auction compared to what revenues would have been using a load forecast that is 3.1 percent below the PJM peak load forecast. (Scenario 3)

Impact of Change in ComEd CETL (Scenario 4)

The decrease in the ComEd CETL of 1,058.0 MW, or 15.5 percent, from the 2022/2023 level to the 2023/2024 level did not have any impact on the auction results.

Table 31 shows the results if the 2022/2023 CETL value for ComEd had been used in the 2023/2024 RPM Base Residual Auction and everything else had remained the same. The results of the scenario show that the ComEd price for the 2023/2024 RPM Base Residual Auction would remain the same if the CETL had remained at the higher 2022/2023 CETL value. All binding constraints would have remained binding. All clearing prices and clearing quantities would have remained the same.

Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2023/2024 RPM Base Residual Auction were $2,196,444,791. If the 2022/2023 CETL value for ComEd had been used in the 2023/2024 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2023/2024 RPM Base Residual Auction would remain the same.

Impact of Change in MAAC CETL (Scenario 5)

The increase in the MAAC CETL of 2,006.0 MW, or 45.9 percent, from the 2022/2023 level to the 2023/2024 level had a limited impact on the auction results. Table 32 shows the results if the 2022/2023 CETL value for MAAC had been used in the 2023/2024 RPM Base Residual Auction and everything else had remained the same. The results of the scenario show that the MAAC price for the 2023/2024 RPM Base Residual Auction would be higher if the CETL had remained at the lower 2022/2023 CETL value. All binding constraints would have remained binding. The RTO clearing price would have decreased to $24.13 per MW-day, and the clearing quantity would have increased to 145,198.6 MW. The clearing quantity of seasonal capacity would have remained the same at 474.1 MW. The MAAC clearing price would have increased to $61.84 per MW-day, and the clearing quantity would have increased to 64,741.6 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have remained the same at 29.3 MW. The DPL South clearing price would have remained the same at $69.95 per MW-day, and the clearing quantity would have remained the same at 1,324.0 MW. The clearing quantity of seasonal capacity for satisfying DPL South's reliability requirement would have remained the same at 0 MW. The BGE clearing price would have remained the same at $69.95 per MW-day, and the clearing quantity would have remained the same at 2,416.0 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW.

Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2023/2024 RPM Base Residual Auction were $2,196,444,791. If the lower 2022/2023 CETL value for MAAC had been used in the 2023/2024 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2023/2024 RPM Base Residual Auction would have been $2,191,931,381, a decrease of $4,513,409, or 0.2 percent, compared to the actual results. From another perspective, the use of 2023/2024 CETL value for MAAC resulted in a 0.2 percent increase in RPM revenues for the 2023/2024 RPM Base Residual Auction compared to what RPM revenues would have using the 2022/2023 CETL value for MAAC.

Impact of Definition of Capacity Issues

The MMU analyzed the impact of specific, significant issues related to the definition of capacity, including: the impact of overstated intermittent capacity; the impact of demand side resources; the impact of EE; the impact of PRD; the impact of seasonal capacity; the impact of seasonal capacity matching across LDAs; and the impact of external capacity resources.

Impact of Overstated Intermittent Capacity (Scenario 6)

Since renewable resources are intermittent, the contribution of renewables to meeting reliability targets must be analyzed carefully to ensure that the capacity value is calculated correctly. On July 30, 2021, FERC approved new rules in PJM for determining the capacity value of intermittent generators, based on a version of the effective load carrying capability (ELCC) method.[161] The MMU opposed PJM's version of the 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 data, among other issues, but does not oppose the ELCC approach in concept and when done correctly. If done correctly, ELCC would be an advance over the current approach to discounting the reliability contribution of intermittent resources.[162] But, both the capacity derating factors applied to intermittent nameplate capacity in the 2022/2023 BRA and the ELCC calculations used for the 2023/2024 BRA are based on the assumption that the intermittent resources can provide reliable output in excess of their CIRs. The defined derating factors and defined ELCC derating factors can be reached only if the intermittent resources can provide reliable output in excess of their CIRs, as currently defined. PJM recalculated the ELCC class ratings for wind and solar resources assuming generation from an ELCC resource is capped at its CIR level.[163] PJM estimated the impact of the revised ELCC ratings to be a reduction of 1,300 MW UCAP for wind and solar units.[164] [165] PJM studied the capacity cost impacts by removing 1,300 MW of wind and

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161 See 176 FERC ¶ 61,056.

162 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).

163 "Impact on Wind & Solar Class UCAP Values by Capping Hourly Outputs in UCAP Calculation at CIR Level," Item 4A in meeting notes for PC Special Session – CIRs for ELCC Resources, PJM Interconnection, LLC, May 19, 2022 <https://pjm.com/committees-and-groups/committees/pc>.

164 PJM included all wind and solar units in the 2026 RTEP with an interconnection service agreement (ISA).

165 "CIRs for ELCC Resources: Cost Assessment of Potential Impacts to PJM Load Customers," Item 2, page 12 in meeting notes for PC Special Sessions – CIRs for ELCC Resources, PJM Interconnection, LLC, June 24, 2022 <https://pjm.com/committees-and-groups/committees/pc>.

solar UCAP from the 2023/2024 BRA.[166] PJM determined the capacity cost increase to be $139 million.

The MMU recalculated the accredited UCAP for each wind and solar resource using PJM's revised ELCC class ratings, and then adjusted the capacity offer to be no higher than the lower of the revised ELCC (accredited UCAP) and the CIR.[167] The adjustments reduced the capacity offers from wind and solar resources by 348.1 MW. There are two reasons for the difference between the 348.1 MW impact calculated by the MMU and the 1,300 MW impact calculated by PJM. PJM calculated the impact based on the maximum capability of the units included in the 2026 RTEP. But some of those resources were not registered for the 2023/2024 BRA and some of those resources that could have offered in the 2023/2024 BRA did not offer. PJM's analysis assumes that all affected units offered the maximum capability into the 2023/2024 BRA. The MMU identified 7,367.2 MW of ELCC capacity eligible for the 2023/2024 BRA but less than half of the eligible ELCC capacity was offered. Capacity offers for the 2023/2024 BRA included 2,651.0 MW of annual capacity from ELCC resources and 47.0 MW of summer capacity.

Table 33 shows the results if the reliability contribution of solar and wind resources were capped at the revised ELCC values.[168] All binding constraints would have remained binding. The RTO clearing price would have increased to $35.40 per MW-day, and the clearing quantity would have decreased to 144,828.9 MW. The clearing quantity of seasonal capacity would have decreased to 472.0 MW. The MAAC clearing price would have increased to $50.46 per MW-day, and the clearing quantity would have decreased to 62,912.3 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have decreased to 29.3 MW. The DPL South clearing price would have remained the same at $69.95 per MW-day, and the clearing quantity would have remained the same at 1,324.0 MW. The clearing quantity of seasonal capacity for satisfying DPL South's reliability requirement would have remained the same at 0 MW. The BGE clearing price would have remained the same at $69.95 per MW-day, and the clearing quantity would have remained the same at 2,416.0 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0.0 MW.

Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2023/2024 RPM Base Residual Auction were $2,196,444,791. If the

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166 "Transitional Costs to Load To Support CIRs for ELCC Resource Solution Packages," Item 2 in meeting notes for PC Special Session – CIRS for ELCC Resources, PJM Interconnection, LLC, September 6, 2022 <https://pjm.com/committees-and-groups/committees/pc>.

167 Seasonal winter offers were not changed as these offers are limited by winter CIRs.

168 There were no offers for battery resources in the 2023/2024 RPM Base Residual Auction.

unforced capacity of solar and wind resources offered in the 2023/2024 RPM Base Residual Auction had been capped at CIR value and everything else had remained the same, total RPM market revenues for the 2023/2024 RPM Base Residual Auction would have been $2,254,726,706, an increase of $58,281,915, or 2.7 percent, compared to the actual results. From another perspective, the inclusion of all offers from solar and wind resources resulted in a 2.6 percent decrease in RPM revenues for the 2023/2024 RPM Base Residual Auction compared to what RPM revenues would have been if offers from solar and wind capacity resources had been capped at the revised ELCC values.

Impact of Demand Resources (Scenario 7)

The inclusion of all sell offers for demand resources, including annual and seasonal, had a significant impact on the auction results. Table 35 shows the results if there were no offers for DR in the 2023/2024 RPM Base Residual Auction and everything else had remained the same. All binding constraints would have remained binding except that the MAAC, the DPL South and the BGE import limits which would not have been binding and EMAAC would have been binding. The RTO clearing price would have increased to $74.26 per MW-day, and the clearing quantity would have decreased to 143,539.5 MW. The clearing quantity of seasonal capacity would have decreased to 297.0 MW. The MAAC clearing price would have increased to $74.26 per MW-day, and the clearing quantity would have decreased to 62,800.9 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have decreased to 28.9 MW. The EMAAC clearing price would have increased to $93.65 per MW-day, and the clearing quantity would have decreased to 29,659.1 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 0 MW. The DPL South clearing price would have increased to $93.65 per MW-day, and the clearing quantity would have increased to 1,330.9 MW. The clearing quantity of seasonal capacity for satisfying DPL South's reliability requirement would have remained the same at 0 MW. The BGE clearing price would have increased to $74.26 per MW-day, and the clearing quantity would have decreased to 2,381.6 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW.

Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2023/2024 RPM Base Residual Auction were $2,196,444,791. If there had been no offers for DR in the 2023/2024 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2023/2024 RPM Base Residual Auction would have been $4,111,765,958, an increase of $1,915,321,168, or 87.2 percent, compared to the actual results. From another perspective, the inclusion of DR resulted in a 46.6 percent reduction in RPM revenues for the 2023/2024 RPM Base Residual Auction compared to what RPM revenues would have been without any DR.

Impact of EE Offers and EE Add Back (Scenario 8)

The inclusion of sell offers for EE, with the EE addback mechanism, had a significant impact on the auction results. The 2023/2024 RPM Base Residual Auction was the fifth BRA that included EE and the EE addback mechanism. RPM rules allow Energy Efficiency Resources to participate on the supply side. An adjustment is made to the demand curve through the EE addback mechanism to avoid affecting the clearing price, because EE for the delivery year is reflected in the revised load forecast model for the same delivery year. PJM did not require EE addback to equal EE cleared in all auctions prior to 2023/2024 Delivery Year. This flawed EE addback mechanism resulted in more EE addback than EE cleared, distorting the clearing prices. Based on the issue charge introduced by the MMU, PJM updated the EE addback rules effective with the 2023/2024 Delivery Year to ensure that the difference between EE addback and EE cleared is minimized.[169] The impact of EE and the addback mechanism in the 2023/2024 BRA was primarily a result of customers paying for a significant level of EE MW and a zero impact from the price increase resulting from the EE addback.

Table 36 shows the results if there were no offers for EE and the EE addback MW were removed in the 2023/2023 RPM Base Residual Auction and everything else had remained the same. All binding constraints would have remained binding. All clearing prices and clearing quantities would have remained the same.

Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2023/2023 RPM Base Residual Auction were $2,196,444,791. If there were no offers for EE and the EE addback MW were removed in the 2022/2023 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2023/2024 RPM Base Residual Auction would have been $2,114,675,175, a decrease of $81,769,616, or 3.7 percent, compared to the actual results. From another perspective, the inclusion of EE offers and the EE addback MW resulted in a 3.9 percent increase in RPM revenues for the 2023/2024 RPM Base Residual Auction compared to what RPM revenues would have been if energy efficiency projects were reflected in the demand and EE did not participate on the supply side. The 3.7 percent increase in total RPM market revenues reflects the amount of EE capacity purchased. EE accounted for 5,471.1 MW of the increase in cleared capacity.

169 "PJM Manual 18: PJM Capacity Market," § 2.4.5 Adjustments to RPM Auction Parameters for EE Resources, Rev. 54 (Sep. 21, 2022).

Impact of Price Responsive Demand (Scenario 9)

The 2023/2024 RPM Base Residual Auction was the second BRA that included submissions for Price Responsive Demand (PRD). The inclusion of PRD had a limited impact on the auction results.

Table 37 shows the results if there were no offers for PRD in the 2023/2024 RPM Base Residual Auction and everything else had remained the same. All binding constraints would have remained binding. The RTO clearing price would have remained the same at $34.13 per MW-day, and the clearing quantity would have increased to 145,126.6 MW. The clearing quantity of seasonal capacity would have remained the same at 474.1 MW. The MAAC clearing price would have remained the same at $49.49 per MW-day, and the clearing quantity would have increased to 63,185.6 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have remained the same at 29.3 MW. The DPL South clearing price would have remained the same at $69.95 per MW-day, and the clearing quantity would have remained the same at 1,340.8 MW. The clearing quantity of seasonal capacity for satisfying DPL South's reliability requirement would have remained the same at 0 MW. The BGE clearing price would have remained the same at $69.95 per MW-day, and the clearing quantity would have increased to 2,510.8 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW.

Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2023/2024 RPM Base Residual Auction were $2,196,444,791. If there had been no submissions from PRD providers in the 2023/2024 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2023/2024 RPM Base Residual Auction would have been $2,206,858,085, an increase of $10,413,294, or 0.5 percent, compared to the actual results. From another perspective, the inclusion of PRD resulted in a 0.5 percent reduction in RPM revenues for the 2023/2024 RPM Base Residual Auction compared to what RPM revenues would have been without any PRD.

The results show that the inclusion of PRD caused price increases in some LDAs. The interaction of the supply offers and the demand curve also contributed to this counter intuitive result.

Impact of Seasonal Products (Scenario 10)

The 2023/2024 RPM Base Residual Auction was the third BRA held using the Seasonal products for summer and winter capacity. The inclusion of seasonal offers (Demand Resources, Energy Efficiency Resources, and Generation Resources) had a significant impact on the auction results.

Table 38 shows the results if there were no offers for Seasonal products (Demand Resources, Energy Efficiency Resources, and Generation Resources) in the 2023/2024 RPM Base Residual Auction and everything else had remained the same. All binding constraints would have remained binding. The RTO clearing price would have increased to $37.00 per MW-day, and the clearing quantity would have decreased to 144,526.4 MW. The clearing quantity of seasonal capacity would have decreased to 0 MW. The MAAC clearing price would have remained the same at $49.49 per MW-day, and the clearing quantity would have decreased to 62,884.8 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have decreased to 0 MW. The DPL South clearing price would have remained the same at $69.95 per MW-day, and the clearing quantity would have remained the same at 1,324.0 MW. The clearing quantity of seasonal capacity for satisfying DPL South's reliability requirement would have remained the same at 0 MW. The BGE clearing price would have remained the same at $69.95 per MW-day, and the clearing quantity would have decreased to 2,414.5 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW.

Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2023/2024 RPM Base Residual Auction were $2,196,444,791. If there had been no offers for Seasonal products in the 2023/2024 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2023/2024 RPM Base Residual Auction would have been $2,277,928,225, an increase of $81,483,434, or 3.7 percent, compared to the actual results. From another perspective, the inclusion of Seasonal offers resulted in a 3.6 percent decrease in RPM revenues for the 2023/2024 RPM Base Residual Auction compared to what RPM revenues would have been without any seasonal products.

Impact of Seasonal Matching Across LDAs (Scenario 11)

Matching seasonal offers across LDAs had a limited impact on the auction results.

Table 39 shows the results if seasonal offers were only matched with complementary seasonal offers within the same LDA in the 2023/2024 RPM Base Residual Auction and everything else had remained the same. All binding constraints would have remained binding. The RTO clearing price would have remained the same at $34.13 per MW-day, and the clearing quantity would have decreased to 144,813.5 MW. The clearing quantity of seasonal capacity would have decreased to 396.3 MW. The MAAC clearing price would have remained the same at $49.49 per MW-day, and the clearing quantity would have decreased to 62,887.5 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have decreased to 2.7 MW. The DPL South clearing price would have remained the same at $69.95 per MW-day, and the clearing quantity would have remained the same at 1,324.0 MW. The clearing quantity of seasonal capacity for satisfying DPL South's reliability requirement would have remained the same at to 0.0 MW. The BGE clearing price would have remained the same at $69.95 per MW-day, and the clearing quantity would have decreased to 2,414.5 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0.0 MW.

Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2023/2024 RPM Base Residual Auction were $2,196,444,791. If seasonal offers were not matched with complementary seasonal offers from the other LDAs in the 2023/2024 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues would have been $2,195,770,974, a decrease of $673,816, or less then 0.1 percent, compared to the actual results. From another perspective, allowing the matching of offers from seasonal products across child LDAs in the same parent LDA resulted in a less than 0.1 percent increase in RPM revenues for the 2023/2024 RPM Base Residual Auction compared to what RPM revenues would have been if seasonal offers were only matched with complementary Seasonal offers within the same LDA.

Impact of Capacity Imports (Scenario 12)

The inclusion of capacity imports in the 2023/2024 RPM Base Residual Auction had a significant impact on the auction results.

Table 41 shows the results if capacity imports in the 2023/2024 RPM Base Residual Auction had been eliminated and everything else had remained the same. All binding constraints would have remained binding. The RTO clearing price would have increased to $37.23 per MW-day, and the clearing quantity would have decreased to 144,768.8 MW. The clearing quantity of seasonal capacity would have remained the same at 474.1 MW. The MAAC clearing price would have remained the same at $49.49 per MW-day, and the clearing quantity would have remained the same at 62,929.5 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have remained the same at 29.3 MW. The DPL South clearing price would have remained the same at $69.95 per MW-day, and the clearing quantity would have remained the same at 1,324.0 MW. The clearing quantity of seasonal capacity for satisfying DPL South's reliability requirement would have remained the same at 0 MW. The BGE clearing price would have remained the same at $69.95 per MW-day, and the clearing quantity would have remained the same at 2,416.0 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW.

Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2023/2024 RPM Base Residual Auction were $2,196,444,791. If capacity imports had been eliminated and everything else had remained the same, total RPM market revenues for the 2023/2023 RPM Base Residual Auction would have been $2,288,709,765, an increase of $92,264,974, or 4.2 percent, compared to the actual results. From another perspective, the impact of including capacity imports resulted in a 4.0 percent reduction in RPM revenues for the 2023/2024 RPM Base Residual Auction compared to what RPM revenues would have been if no capacity imports were included in the auction.

Impact of Combined Scenarios 6, 7, 8, 9, 10, 12 (Scenario 13)

The combined impact of issues related to the definition of capacity had a significant impact on the auction results. Together, the overstatement of intermittent MW offers, and the inclusion of sell offers from DR, EE, PRD, seasonal products, and imports had a significant combined impact on the auction results.

Table 42 shows the results if there were no offers for DR, EE, PRD, or seasonal products, imports, and no intermittent capacity overstatement in the 2023/2024 RPM Base Residual Auction and everything else had remained the same. All binding constraints would have remained binding except that the MAAC, BGE and DPL South import limits would not have been binding and EMAAC import limit would have been binding. The RTO clearing price would have increased to $97.48 per MW-day, and the clearing quantity would have decreased to 137,577.6 MW. The clearing quantity of seasonal capacity would have decreased to 0 MW. The MAAC clearing price would have increased to $97.48 per MW-day, and the clearing quantity would have decreased to 62,140.9 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have decreased to 0 MW. The EMAAC clearing price would have increased to $98.51 per MW-day, and the clearing quantity would have decreased to 28,479.5 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 0 MW. The DPL South clearing price would have increased to $98.51 per MW-day, and the clearing quantity would have decreased to 1,274.8 MW. The clearing quantity of seasonal capacity for satisfying DPL South's reliability requirement would have remained the same at 0 MW. The BGE clearing price would have increased to $97.48 per MW-day, and the clearing quantity would have decreased to 2,279.0 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW.

Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2023/2024 RPM Base Residual Auction were $2,196,444,791. If there had been no overstatement of intermittent MW offers and no offers from DR, EE, PRD, seasonal products, or imports in the 2023/2024 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2023/2024 RPM Base Residual Auction would have been $4,919,185,790, an increase of $2,722,740,999, or 124.0 percent, compared to the actual results. From another perspective, the inclusion of overstated intermittent MW offers, and offers from DR, EE, PRD, seasonal products and imports resulted in a 55.3 percent reduction in RPM revenues for the 2023/2024 RPM Base Residual Auction compared to what RPM revenues would have been without overstated intermittent MW offers, and offers from DR, EE, PRD, seasonal products and imports.

Impact of Market Behavior Issues

The MMU analyzed the impact of offers from nuclear plants.

Impact of Nuclear Offers (Scenario 14)

Nuclear offer behavior in the 2022/2023 RPM Base Residual Auction was comparable to that in the 2021/2022 BRA. In both the 2022/2023 BRA and the 2021/2022 BRA a significant level of nuclear capacity was offered at higher sell offer prices than in the 2020/2021 BRA, and fewer nuclear MW cleared in the 2022/2023 BRA and 2021/2022 BRA than in the 2020/2021 RPM BRA. (See 22 and Table 23). To define an upper bound on the impact of nuclear offers, a scenario setting all nuclear offers to $0 per MW-day was analyzed. It is not asserted that a $0 per MW-day sell offer is the competitive offer for all nuclear resources.

A substantial amount of nuclear capacity was offered in the 2022/2023 RPM Base Residual Auction and 2021/2022 RPM BRA at higher sell offer prices and fewer nuclear MW cleared compared to 2020/2021 RPM Base Residual Auction (See 22 and Table 23).[170] [171] To define an upper bound on the impact of nuclear offers, a scenario setting all nuclear offers to $0 per MW-day was analyzed. The MMU does not assert that a $0 per MW-day sell offer was a competitive offer for all nuclear resources.

Table 43 shows the results of the 2023/2024 RPM Base Residual Auction had all nuclear offers been replaced with $0 per MW-day and everything else had remained the same. All binding constraints would have remained binding. All clearing prices and clearing quantities would have remained the same.

Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2023/2024 RPM Base Residual Auction were $2,196,444,791. If all nuclear offers were replaced by $0 per MW-day nuclear offers in the 2023/2024 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 202/2024 RPM Base Residual Auction would remain the same.

Impact of Combined Scenarios 2, 6, 7, 12 (Scenario 15)

The impact of some of the identified market design flaws reduced capacity market prices and the impact of other identified market design flaws increased capacity market prices. The combined impact of the identified market design flaws was to reduce capacity market revenues by 24.3 percent in the 2023/2024 BRA. The identified market design flaws are:

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170 See PJM. News Releases, May 23, 2018. <http://www.pjm.com/-/media/about-pjm/newsroom/2018-releases/20180523-rpm-results-2021-2022-news-release.ashx>.

171 See PJM. News Releases, June 2, 2021. <https://www.pjm.com/-/media/about-pjm/newsroom/2021-releases/20210602-pjm-successfully-clears-capacity-auction-to-ensure-reliable-electricity-supplies.ashx>.

the shape of the VRR curve; the overstatement of intermittent MW offers; the inclusion of sell offers from DR; and capacity imports.

Table 44 shows the results if all of the identified market design flaws had been corrected in the 2023/2024 RPM Base Residual Auction and everything else had remained the same. All binding constraints would have remained binding except that the MAAC import limit would not have been binding. The RTO clearing price would have increased to $55.85 per MW-day, and the clearing quantity would have decreased to 140,596.1 MW. The clearing quantity of seasonal capacity would have decreased to 294.9 MW. The MAAC clearing price would have increased to $55.85 per MW-day, and the clearing quantity would have decreased to 61,897.1 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have decreased to 28.9 MW. The DPL South clearing price would have remained the same at $69.95 per MW-day, and the clearing quantity would have decreased to 1,245.7 MW. The clearing quantity of seasonal capacity for satisfying DPL South's reliability requirement would have remained the same at 0 MW. The BGE clearing price would have remained the same at $69.95 per MW-day, and the clearing quantity would have decreased to 2,242.5 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW.

Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2023/2024 RPM Base Residual Auction were $2,196,444,791. If all of the identified market design flaws had been corrected in the 2023/2024 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2023/2024 RPM Base Residual Auction would have been $2,901,559,097, an increase of $705,114,306, or 32.1 percent, compared to the actual results. From another perspective, the identified market design flaws resulted in a 24.3 percent reduction in RPM revenues for the 2023/2024 RPM Base Residual Auction compared to what RPM revenues would have been without those flaws.

Tables and Figures for RTO Market

Table 8 RTO offer statistics: 2023/2024 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	189,641.0	181,058.3		
DR capacity	10,963.0	11,948.9		
EE capacity	5,037.8	5,491.0		
Generation winter capacity	961.7	961.7		
Total internal RTO capacity	206,603.5	199,459.9		
FRR	(33,991.5)	(31,828.0)		
Imports	1,601.2	1,528.0		
RPM capacity	174,213.2	169,159.9		
Exports	(2,573.9)	(2,517.9)		
FRR optional	(1,211.6)	(1,078.5)		
Excused Existing Generation Capacity Resources	(3,344.4)	(2,639.3)		
Unoffered Planned Generation Capacity Resources	(157.0)	(149.3)		
Unoffered Intermittent Resources	(3,722.3)	(3,720.9)		
Unoffered Capacity Storage Resources	(1,051.3)	(1,051.3)		
Unoffered generation winter capacity	(536.2)	(536.2)		
Unoffered DR and EE	(1,304.9)	(1,422.4)		
Available	160,311.6	156,044.0	100.0%	100.0%
Generation offered	146,106.5	140,561.5	91.1%	90.1%
DR offered	9,299.6	10,135.7	5.8%	6.5%
EE offered	4,905.5	5,346.8	3.1%	3.4%
Total offered	160,311.6	156,044.0	100.0%	100.0%
Unoffered Existing Generation Capacity Resources	0.0	0.0	0.0%	0.0%

Table 9 Capacity modifications (ICAP): 2023/2024 RPM Base Residual Auction[172]

	ICAP (MW)			
	RTO	MAAC	DPL South	BGE
Generation increases	5,217.9	529.6	52.2	0.0
Generation decreases	(8,582.4)	(3,535.1)	(8.7)	(159.4)
Capacity modifications net increase/(decrease)	(3,364.5)	(3,005.5)	43.5	(159.4)
DR increases	1,405.5	630.7	12.1	38.9
DR decreases	(1,065.3)	(423.0)	0.0	(11.6)
DR net increase/(decrease)	340.2	207.7	12.1	27.3
EE increases	3,212.6	1,341.7	23.7	151.4
EE decreases	(2,871.7)	(1,139.9)	(22.5)	(99.7)
EE modifications increase/(decrease)	340.9	201.8	1.2	51.7
Net internal capacity increase/(decrease)	(2,683.4)	(2,596.0)	56.8	(80.4)

Table 10 Capacity modifications (UCAP): 2023/2024 RPM Base Residual Auction

	UCAP (MW)			
	RTO	MAAC	DPL South	BGE
Generation increases	5,171.9	531.1	52.2	0.0
Generation decreases	(7,469.3)	(3,181.3)	(8.5)	(119.0)
Capacity modifications net increase/(decrease)	(2,297.4)	(2,650.2)	43.7	(119.0)
DR increases	1,529.9	686.5	13.2	42.3
DR decreases	(1,157.4)	(459.5)	0.0	(12.6)
DR net increase/(decrease)	372.5	227.0	13.2	29.7
EE increases	3,493.4	1,459.6	25.9	164.6
EE decreases	(3,120.1)	(1,238.4)	(24.4)	(108.3)
EE modifications increase/(decrease)	373.3	221.2	1.5	56.3
Net capacity/DR/EE modifications increase/(decrease)	(1,551.6)	(2,202.0)	58.4	(33.0)
EFORd effect	(1,305.4)	(423.9)	(2.5)	(56.1)
DR and EE effect	52.9	17.2	0.3	1.5
Net internal capacity increase/(decrease)	(2,804.1)	(2,608.7)	56.2	(87.6)

172 Only cap mods that had a start date on or before June 1, 2023, and DR and EE plans for the 2023/2024 RPM Base Residual Auction are included.

Table 11 Winter capacity modifications (ICAP): 2023/2024 RPM Base Residual Auction

	ICAP (MW)			
	RTO	MAAC	DPL South	BGE
Generation increases	535.0	6.3	0.0	0.0
Generation decreases	(519.6)	(127.9)	0.0	0.0
Capacity modifications net increase/(decrease)	15.4	(121.6)	0.0	0.0
DR increases	0.0	0.0	0.0	0.0
DR decreases	0.0	0.0	0.0	0.0
DR net increase/(decrease)	0.0	0.0	0.0	0.0
EE increases	0.0	0.0	0.0	0.0
EE decreases	0.0	0.0	0.0	0.0
EE modifications increase/(decrease)	0.0	0.0	0.0	0.0
Net internal capacity increase/(decrease)	15.4	(121.6)	0.0	0.0

Table 12 Winter capacity modifications (UCAP): 2023/2024 RPM Base Residual Auction

	UCAP (MW)			
	RTO	MAAC	DPL South	BGE
Generation increases	535.0	6.3	0.0	0.0
Generation decreases	(519.6)	(127.9)	0.0	0.0
Capacity modifications net increase/(decrease)	15.4	(121.6)	0.0	0.0
DR increases	0.0	0.0	0.0	0.0
DR decreases	0.0	0.0	0.0	0.0
DR net increase/(decrease)	0.0	0.0	0.0	0.0
EE increases	0.0	0.0	0.0	0.0
EE decreases	0.0	0.0	0.0	0.0
EE modifications increase/(decrease)	0.0	0.0	0.0	0.0
Net capacity/DR/EE modifications increase/(decrease)	15.4	(121.6)	0.0	0.0
EFORd effect	0.0	0.0	0.0	0.0
DR and EE effect	0.0	0.0	0.0	0.0
Net internal capacity increase/(decrease)	15.4	(121.6)	0.0	0.0

Table 13 Installed and offered generation capacity by parent company: 2023/2024 RPM Base Residual Auction

Parent Company	ICAP (MW)	Percent of Total ICAP	Offered ICAP (MW)	Percent of Total Offered ICAP
Dominion Resources, Inc.	21,521.0	11.2%	236.7	0.2%
Constellation Energy Generation, LLC	20,231.3	10.5%	19,027.7	13.0%
American Electric Power Company, Inc.	15,031.0	7.8%	2,324.1	1.6%
ArcLight Capital Partners, LLC	14,829.0	7.7%	13,774.0	9.4%
LS Power Group	11,021.1	5.7%	10,941.1	7.5%

Table 14 Net load prices: 2023/2024 RPM Base Residual Auction

	$ per MW-day				
	RTO	MAAC	EMAAC	DPL	BGE
Resource clearing price	$34.13	$49.49	$49.49	$69.95	$69.95
Preliminary zonal capacity price	$34.13	$49.49	$49.49	$56.40	$71.21
Adjusted preliminary zonal capacity price	$34.20	$49.70	$49.59	$56.57	$71.62
Base zonal CTR credit rate	$0.00	$0.00	$0.00	($0.02)	$12.79
Preliminary net load price	$34.20	$49.70	$49.59	$56.59	$58.83

Table 15 Clearing prices: 2022/2023 and 2023/2024 RPM Base Residual Auctions

			Change	
LDA	2022/2023 BRA	2023/2024 BRA	$ per MW-Day	Percent
RTO	$50.00	$34.13	($15.87)	(46.5%)
MAAC	$95.79	$49.49	($46.30)	(93.6%)
EMAAC	$97.86	$49.49	($48.37)	(97.7%)
SWMAAC	$95.79	$49.49	($46.30)	(93.6%)
PSEG	$97.86	$49.49	($48.37)	(97.7%)
PSEG North	$97.86	$49.49	($48.37)	(97.7%)
DPL South	$97.86	$69.95	($27.91)	(39.9%)
Pepco	$95.79	$49.49	($46.30)	(93.6%)
ATSI	$50.00	$34.13	($15.87)	(46.5%)
ATSI Cleveland	$50.00	$34.13	($15.87)	(46.5%)
ComEd	$68.96	$34.13	($34.83)	(102.1%)
BGE	$126.50	$69.95	($56.55)	(80.8%)
PPL	$95.79	$49.49	($46.30)	(93.6%)
DAY	$50.00	$34.13	($15.87)	(46.5%)
DEOK	$71.69	$34.13	($37.56)	(110.0%)

Table 16 Reserve margin: 2023/2024 RPM Base Residual Auction

	Reserve Margin Calculation	
Forecast peak load ICAP (MW)	149,680.0	A
FRR peak load ICAP (MW)	28,755.0	B
PRD ICAP (MW)	235.0	C
Installed reserve margin (IRM)	14.8%	D
Pool-wide average EFORd	5.04%	E
Forecast pool requirement (FPR)	1.0901	F=(1+D)*(1-E)
Cleared UCAP (generation and DR)	139,399.5	G
Cleared ICAP (generation and DR)	146,798.1	H=G/(1-E)
RPM peak load ICAP (MW)	120,690.0	J=A-B-C
Reserve margin ICAP (MW)	26,108.1	K=H-J
Reserve margin (%)	21.6%	L=K/J
Reserve cleared in excess of IRM ICAP (MW)	8,246.0	M=K-D*J
Reserve cleared in excess of IRM (%)	6.8%	N=M/J
RPM peak load UCAP (MW)	114,607.2	P=J*(1-E)
RPM reliability requirement UCAP (MW)	131,564.2	Q=J*F
Reserve margin UCAP (MW)	24,792.3	R=G-P
Reserve cleared in excess of IRM UCAP (MW)	7,835.3	S=G-Q

Table 17 Net excess: 2023/2024 RPM Base Residual Auction

	UCAP (MW)				
	RTO	MAAC	DPL South	BGE	
Cleared generation and DR	139,399.5	60,746.9	1,272.8	2,159.8	A
CETL	NA	6,381.0	2,008.0	5,615.0	B
Reliability requirement	163,166.2	63,819.0	3,141.0	7,522.0	C
FRR peak load	28,755.0	0.0	0.0	0.0	D
PRD	235.0	235.0	15.4	87.0	E
FPR	1.0901	1.0901	1.0901	1.0901	F
Reliability requirement adjusted for FRR and PRD	131,564.2	63,562.8	3,124.2	7,427.2	G=C-D*F-E*F
Net excess/(deficit)	7,835.3	3,565.1	156.6	347.6	H=A+B-G

Table 18 Offered and cleared capacity by LDA, resource type, and season type: 2023/2024 RPM Base Residual Auction

		Offered UCAP (MW)			Cleared UCAP (MW)		
LDA	Resource Type	Annual	Summer	Winter	Annual	Summer	Winter
RTO	GEN	139,803.4	207.6	550.5	130,745.8	207.6	455.2
RTO	DR	9,939.6	161.7	34.4	7,919.1	161.7	34.4
RTO	EE	5,221.1	125.7	0.0	5,221.1	125.7	0.0
MAAC	GEN	62,560.8	0.4	14.6	58,350.2	0.4	14.6
MAAC	DR	3,072.6	7.5	0.0	2,396.4	7.5	0.0
MAAC	EE	2,153.5	22.5	0.0	2,153.5	22.5	0.0
DPL South	GEN	1,279.7	0.0	0.0	1,220.6	0.0	0.0
DPL South	DR	53.8	0.0	0.0	52.2	0.0	0.0
DPL South	EE	51.2	0.0	0.0	51.2	0.0	0.0
BGE	GEN	2,423.4	0.0	0.0	1,992.1	0.0	0.0
BGE	DR	211.9	0.0	0.0	168.4	0.0	0.0
BGE	EE	255.5	0.8	0.0	255.5	0.8	0.0

Table 19 Weighted average sell offer prices by LDA, resource type, and season type: 2023/2024 RPM Base Residual Auction

		Weighted-Average ($ per MW-day UCAP)		
LDA	Resource Type	Annual	Summer	Winter
RTO	GEN	$10.47	$0.41	$1.37
RTO	DR	$28.49	$0.00	$0.00
RTO	EE	$4.88	$0.00	

Table 20 Offered generation capacity by resource type, season type and price range relative to market seller offer cap (MSOC): 2023/2024 RPM Base Residual Auction

	Offered UCAP (MW)		
Season Type	< MSOC	= MSOC	> MSOC
Annual	58,880.4	79,887.9	1,035.1
Summer	0.0	207.6	0.0
Winter	37.6	512.9	0.0

Table 21 Weighted average sell offer prices and market seller offer caps: 2023/2024 RPM Base Residual Auction[173]

		Weighted-Average ($ per MW-day UCAP)	
LDA	Resource Type	Sell Offers	Market Seller Offer Caps
RTO	GEN	$10.44	$26.70

Table 22 Cleared MW by zone and resource type/fuel source: 2023/2024 RPM Base Residual Auction[174]

	Cleared UCAP (MW)										
Zone	DR	EE	Coal	Gas	Hydro	Nuclear	Oil	Solar	Solid Waste	Wind	Total
AECO	55.2	77.2	0.0	1,103.7	0.0	0.0	21.1	19.8	0.0	0.0	1,277.0
AEP	1,284.8	589.7	5,113.5	11,484.5	40.0	128.7	0.0	420.9	0.0	390.2	19,452.3
AP	716.2	250.3	2,948.8	4,001.5	99.7	0.0	0.0	62.7	0.0	78.8	8,158.0
ATSI	851.5	420.3	124.4	5,477.5	0.0	2,113.1	488.9	60.2	0.0	0.0	9,535.9
BGE	168.4	256.3	1,103.4	316.6	0.0	1,704.3	530.5	0.0	41.6	0.0	4,121.1
ComEd	1,286.9	888.8	1,807.2	10,517.4	0.0	10,014.3	240.0	0.0	0.0	614.3	25,368.9
DAY	209.3	92.9	0.0	893.7	0.0	0.0	34.0	35.3	0.0	0.0	1,265.2
DEOK	175.4	155.4	953.9	502.8	66.6	0.0	0.0	112.3	0.0	0.0	1,966.4
DLCO	118.2	123.5	0.0	302.9	0.0	1,468.1	16.3	0.0	0.0	0.0	2,029.0
Dominion	799.1	649.9	427.7	4,217.8	1,044.3	218.5	15.8	962.1	114.6	31.6	8,481.5
DPL	146.9	131.3	0.0	3,478.1	0.0	0.0	584.6	184.0	0.0	0.0	4,524.9
EKPC	269.9	0.0	1,638.1	1,058.7	105.8	0.0	0.0	0.0	0.0	0.0	3,072.5
External	0.0	0.0	836.5	161.1	299.5	99.5	0.0	0.0	0.0	0.0	1,396.6
JCPL	120.5	198.2	0.0	2,995.0	402.0	0.0	205.6	87.1	0.0	0.0	4,008.4
Met-Ed	216.2	104.5	34.9	2,589.2	15.7	0.0	393.7	0.0	52.0	0.0	3,406.2
OVEC	0.0	0.0	1,196.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,196.4
PECO	378.4	379.4	0.0	4,194.1	494.7	4,760.1	759.1	0.0	96.6	0.0	11,062.4
PENELEC	292.3	85.7	2,695.7	2,766.6	511.9	0.0	83.1	89.6	40.4	126.7	6,692.0
Pepco	167.7	277.6	0.0	3,510.8	0.0	0.0	266.6	0.8	44.1	0.0	4,267.7
PPL	583.4	283.5	2,020.8	8,341.3	596.5	2,468.5	41.0	6.8	8.2	2.7	14,352.7
PSEG	272.7	380.9	0.0	5,003.6	0.7	3,390.0	0.0	18.2	165.9	0.0	9,232.0
RECO	2.2	1.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.7
Total	8,115.2	5,346.8	20,901.3	72,916.9	3,677.4	26,365.1	3,680.3	2,059.8	563.4	1,244.3	144,870.6

[173] The underlying data used for Table 19 includes all sell offers. The underlying data used for Table 21 includes only those sell offers subject to market seller offer caps.

[174] Resources that operate at or above 500 kV may be physically located in a zonal LDA but are modeled in the parent LDA. For example, 3,390.0 MW of the 9,232.0 cleared MW in the PSEG Zone were modeled and cleared in the EMAAC LDA.

Table 23 Uncleared generation offers by technology type and age: 2023/2024 RPM Base Residual Auction[175] [176]

	Uncleared UCAP (MW)		
Technology Type	Less Than or Equal to 40 Years Old	Greater than 40 Years Old	Total
Coal Fired	274.2	4,942.0	5,216.2
Combustion turbine	1,850.9	144.6	1,995.5
Nuclear	0.0	0.0	0.0
Wind	95.3	0.0	95.3
Other	377.6	1,272.0	1,649.6
Total	2,598.0	6,358.6	8,956.6

Table 24 Uncleared generation resources in multiple auctions[177] [178]

	2023/2024		2022/2023 Results for Same Set of Resources		2021/2022 Results for Same Set of Resources	
Technology	Uncleared UCAP (MW)	Number of Resources	Uncleared UCAP (MW)	Number of Resources	Uncleared UCAP (MW)	Number of Resources
Coal Fired	5,216.2	22	696.1	13	56.9	10
Combustion turbine	1,995.5	34	490.7	23	109.6	21
Nuclear	0.0	0	0.0	0	0.0	0
Other	1,744.9	40	237.0	16	30.6	3
Total	8,956.6	96	1,423.8	52	197.1	34

175 Effective for the 2017/2018 and subsequent delivery years, the ACR technology classes of waste coal small and large were eliminated and combined with subcritical and supercritical coal to form the Coal Fired ACR technology class. Waste coal resources were included in the other category in versions of this table prior to the 2017/2018 BRA. For the 2023/2024 BRA, waste coal resources are included in the coal fired category.

176 Data aggregated based on PJM confidentiality rules.

177 Effective for the 2017/2018 and subsequent delivery years, the ACR technology classes of waste coal small and large were eliminated and combined with subcritical and supercritical coal to form the Coal Fired ACR technology class. Waste coal resources were included in the other category in versions of this table prior to the 2017/2018 BRA. For the 2023/2024 BRA, waste coal resources are included in the coal fired category.

178 Data aggregated based on PJM confidentiality rules.

Table 25 Offers greater than $35.00 per MW-day in total RTO supply curve: 2023/2024 RPM Base Residual Auction[179] [180]

Technology/Resource Type	Offered UCAP (MW)	Percent of Offers
Coal fired	9,320.2	50.9%
Combustion turbine	2,838.1	15.5%
Demand Resource	2,440.3	13.3%
Other generation (combined cycle, oil or gas steam, solar)	3,694.5	20.2%
Total	18,293.1	100.0%

Table 26 PJM LDA CETL and CETO values: 2022/2023 and 2023/2024 RPM Base Residual Auctions

	2022/2023			2023/2024			Change			
							CETO		CETL	
LDA	CETO	CETL	CETL to CETO Ratio	CETO	CETL	CETL to CETO Ratio	MW	Percent	MW	Percent
MAAC	(7,440.0)	4,375.0	(58.8%)	(4,660.0)	6,381.0	(136.9%)	2,780.0	(37.4%)	2,006.0	45.9%
EMAAC	2,800.0	9,173.0	327.6%	3,210.0	8,704.0	271.2%	410.0	14.6%	(469.0)	(5.1%)
SWMAAC	4,120.0	8,310.0	201.7%	5,790.0	8,389.0	144.9%	1,670.0	40.5%	79.0	1.0%
PSEG	5,740.0	8,626.0	150.3%	5,450.0	9,022.0	165.5%	(290.0)	(5.1%)	396.0	4.6%
PSEG North	2,680.0	4,360.0	162.7%	2,420.0	4,349.0	179.7%	(260.0)	(9.7%)	(11.0)	(0.3%)
DPL South	1,480.0	2,053.0	138.7%	1,360.0	2,008.0	147.6%	(120.0)	(8.1%)	(45.0)	(2.2%)
Pepco	2,380.0	6,781.0	284.9%	3,940.0	7,160.0	181.7%	1,560.0	65.5%	379.0	5.6%
ATSI	4,610.0	9,119.0	197.8%	4,230.0	10,213.0	241.4%	(380.0)	(8.2%)	1,094.0	12.0%
ATSI Cleveland	3,310.0	5,229.0	158.0%	3,550.0	4,728.0	133.2%	240.0	7.3%	(501.0)	(9.6%)
ComEd	(2,130.0)	6,839.0	(321.1%)	(4,060.0)	5,781.0	(142.4%)	(1,930.0)	90.6%	(1,058.0)	(15.5%)
BGE	4,780.0	5,683.0	118.9%	4,660.0	5,615.0	120.5%	(120.0)	(2.5%)	(68.0)	(1.2%)
PPL	(500.0)	4,850.0	(970.0%)	0.0	4,916.0	NA	500.0	(100.0%)	66.0	1.4%
DAY	2,230.0	3,941.0	176.7%	2,510.0	4,022.0	160.2%	280.0	12.6%	81.0	2.1%
DEOK	2,710.0	5,465.0	201.7%	3,270.0	5,632.0	172.2%	560.0	20.7%	167.0	3.1%

179 Effective for the 2017/2018 and subsequent delivery years, the ACR technology classes of waste coal small and large were eliminated and combined with subcritical and supercritical coal to form the Coal Fired ACR technology class. Waste coal resources were included in the other category in versions of this table prior to the 2017/2018 BRA. For the 2023/2024 BRA, waste coal resources are included in the coal fired category.

180 Data aggregated based on PJM confidentiality rules.

Figure 1 Shape of the VRR curve relative to the reliability requirement: 2023/2024 RPM Base Residual Auction

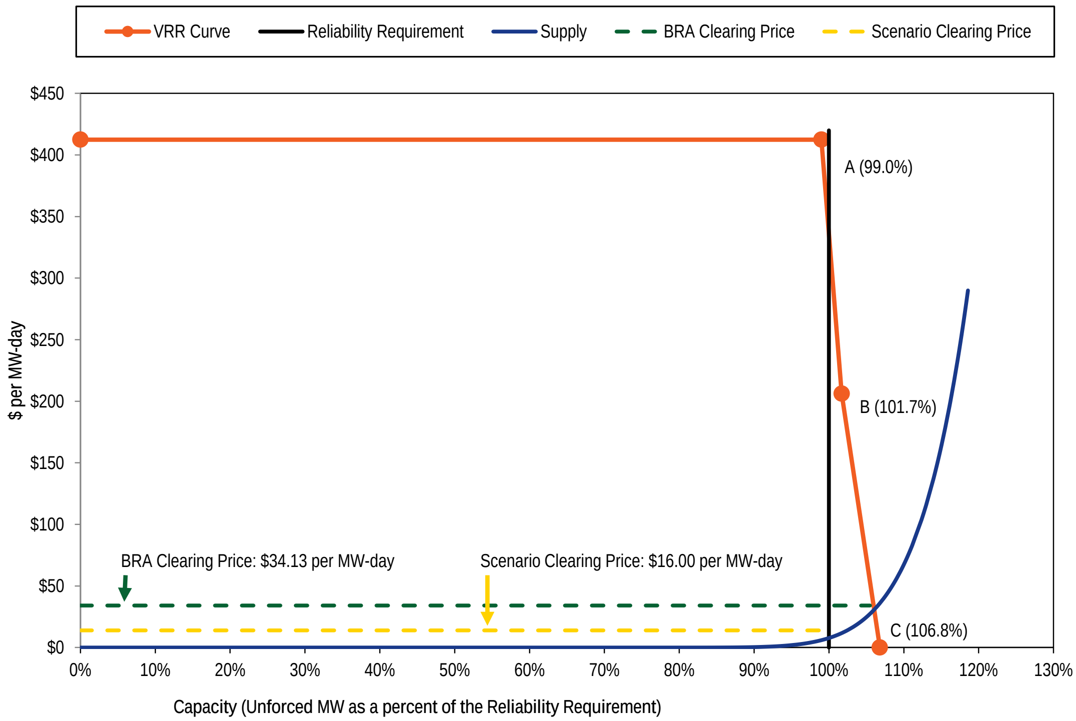


Table 27 Impact of using downward sloping VRR curve: 2023/2024 RPM Base Residual Auction

Scenario 1

		Actual Auction Results		Impact of Using Vertical Reliability Requirement	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$34.13	144,396.5	$16.00	131,090.2
	Summer	$34.13	474.1	$16.00	474.1
	Winter	$34.13	474.1	$16.00	474.1
RTO Total			144,870.6		131,564.3
MAAC	Annual	$49.49	62,900.1	$35.79	57,152.6
	Summer	$49.49	29.3	$35.79	29.3
	Winter	$49.49	29.3	$35.79	29.3
MAAC Total			62,929.4		57,181.9
DPL South	Annual	$69.95	1,324.0	$35.79	1,235.6
	Summer	$69.95	0.0	$35.79	0.0
	Winter	$69.95	0.0	$35.79	0.0
DPL South Total			1,324.0		1,235.6
BGE	Annual	$69.95	2,416.0	$69.90	1,812.2
	Summer	$69.95	0.0	$69.90	0.0
	Winter	$69.95	0.0	$69.90	0.0
BGE Total			2,416.0		1,812.2

Table 28 Impact of using modified VRR curve: 2023/2024 RPM Base Residual Auction Scenario 2

		Actual Auction Results		Impact of Using Modified Reliability Requirement	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$34.13	144,396.5	$24.00	140,645.2
	Summer	$34.13	474.1	$24.00	474.1
	Winter	$34.13	474.1	$24.00	474.1
RTO Total			144,870.6		141,119.3
MAAC	Annual	$49.49	62,900.1	$47.39	61,142.1
	Summer	$49.49	29.3	$47.39	29.3
	Winter	$49.49	29.3	$47.39	29.3
MAAC Total			62,929.4		61,171.4
DPL South	Annual	$69.95	1,324.0	$47.39	1,257.8
	Summer	$69.95	0.0	$47.39	0.0
	Winter	$69.95	0.0	$47.39	0.0
DPL South Total			1,324.0		1,257.8
BGE	Annual	$69.95	2,416.0	$69.95	2,242.5
	Summer	$69.95	0.0	$69.95	0.0
	Winter	$69.95	0.0	$69.95	0.0
BGE Total			2,416.0		2,242.5

Table 29 Peak load forecast history[181] [182]

	DY	BRA	First IA	Second IA	Third IA	Actual DY Peak Load	Percent Change BRA to 1st	Percent Change BRA to 2nd	Percent Change BRA to 3rd	Percent Change BRA to Actual
Forecast Peak Load	2022 / 2023	150,229.0	NA	NA	149,263.6		NA	NA	(0.6%)	
Installed Reverve Margin		14.5%	NA	NA	14.9%		NA	NA	2.8%	
Pool Wide EFORd		5.08%	NA	NA	5.08%		NA	NA	0.0%	
Forecast Pool Requirement		1.0868	NA	NA	1.0906		NA	NA	0.3%	
Reliability Requirement		163,268.9	NA	NA	162,786.9		NA	NA	(0.3%)	
Forecast Peak Load	2021 / 2022	152,647.4	151,832.3	147,501.6	149,482.9	148,750.9	(0.5%)	(3.4%)	(2.1%)	(2.6%)
Installed Reverve Margin		15.8%	15.8%	15.1%	14.7%		0.0%	(4.4%)	(7.0%)	
Pool Wide EFORd		5.89%	6.01%	5.56%	5.22%		2.0%	(5.6%)	(11.4%)	
Forecast Pool Requirement		1.0898	1.0884	1.087	1.0871		(0.1%)	(0.3%)	(0.2%)	
Reliability Requirement		166,355.1	165,254.3	160,334.2	162,502.9		(0.7%)	(3.6%)	(2.3%)	
Forecast Peak Load	2020 / 2021	153,915.0	152,245.4	151,155.1	148,355.3	144,572.8	(1.1%)	(1.8%)	(3.6%)	(6.1%)
Installed Reverve Margin		16.6%	15.90%	15.9%	15.5%		(4.2%)	(4.2%)	(6.6%)	
Pool Wide EFORd		6.59%	5.97%	6.04%	5.78%		(9.4%)	(8.3%)	(12.3%)	
Forecast Pool Requirement		1.0892	1.0898	1.0890	1.0882		0.1%	(0.0%)	(0.1%)	
Reliability Requirement		167,644.2	165,917.0	164,607.9	161,440.2		(1.0%)	(1.8%)	(3.7%)	
Forecast Peak Load	2019 / 2020	157,188.5	154,510.0	152,760.7	151,643.5	151,552.2	(1.7%)	(2.8%)	(3.5%)	(3.6%)
Installed Reverve Margin		16.5%	16.60%	15.9%	16.0%		0.6%	(3.6%)	(3.0%)	
Pool Wide EFORd		6.60%	6.59%	5.99%	6.08%		(0.2%)	(9.2%)	(7.9%)	
Forecast Pool Requirement		1.0881	1.0892	1.0896	1.0895		0.1%	0.1%	0.1%	
Reliability Requirement		171,036.8	168,292.3	166,448.1	165,215.6		(1.6%)	(2.7%)	(3.4%)	
Forecast Peak Load	2018 / 2019	161,418.4	156,141.1	154,179.9	152,407.9	150,639.9	(3.3%)	(4.5%)	(5.6%)	(6.7%)
Installed Reverve Margin		15.7%	16.50%	16.70%	16.1%		5.1%	6.4%	2.5%	
Pool Wide EFORd		6.35%	6.58%	6.59%	6.07%		3.6%	3.8%	(4.4%)	
Forecast Pool Requirement		1.0835	1.0883	1.0901	1.0905		0.4%	0.6%	0.6%	
Reliability Requirement		174,896.8	169,928.4	168,071.5	166,200.8		(2.8%)	(3.9%)	(5.0%)	

181 The 2022/2023 BRA was originally scheduled for May 2019 but was delayed until June 2021. The First and Second IAs for 2022/2023 were not held and the Third IA was held in March 2022, just over nine months after the 2022/2023 BRA. Typically, the time between a BRA and the 3rd IA is two years and 10 months.

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

Table 30 Impact of over forecasted peak load: 2023/2024 RPM Base Residual Auction Scenario 3

		Actual Auction Results		Reduce Load Forecast by 4.3 Percent	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$34.13	144,396.5	$22.00	139,420.9
	Summer	$34.13	474.1	$22.00	474.1
	Winter	$34.13	474.1	$22.00	474.1
RTO Total			144,870.6		139,895.0
MAAC	Annual	$49.49	62,900.1	$47.29	60,845.6
	Summer	$49.49	29.3	$47.29	29.3
	Winter	$49.49	29.3	$47.29	29.3
MAAC Total			62,929.4		60,874.9
DPL South	Annual	$69.95	1,324.0	$47.29	1,257.8
	Summer	$69.95	0.0	$47.29	0.0
	Winter	$69.95	0.0	$47.29	0.0
DPL South Total			1,324.0		1,257.8
BGE	Annual	$69.95	2,416.0	$97.54	2,109.3
	Summer	$69.95	0.0	$97.54	0.0
	Winter	$69.95	0.0	$97.54	0.0
BGE Total			2,416.0		2,109.3

Table 31 Impact of ComEd CETL change: 2023/2024 RPM Base Residual Auction Scenario 4

		Actual Auction Results		ComEd CETL	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$34.13	144,396.5	$34.13	144,396.4
	Summer	$34.13	474.1	$34.13	474.1
	Winter	$34.13	474.1	$34.13	474.1
RTO Total			144,870.6		144,870.5
MAAC	Annual	$49.49	62,900.1	$49.49	62,900.2
	Summer	$49.49	29.3	$49.49	29.3
	Winter	$49.49	29.3	$49.49	29.3
MAAC Total			62,929.4		62,929.5
DPL South	Annual	$69.95	1,324.0	$69.95	1,324.0
	Summer	$69.95	0.0	$69.95	0.0
	Winter	$69.95	0.0	$69.95	0.0
DPL South Total			1,324.0		1,324.0
BGE	Annual	$69.95	2,416.0	$69.95	2,416.0
	Summer	$69.95	0.0	$69.95	0.0
	Winter	$69.95	0.0	$69.95	0.0
BGE Total			2,416.0		2,416.0

Table 32 Impact of MAAC CETL: 2023/2024 RPM Base Residual Auction Scenario 5

LDA	Product Type	Actual Auction Results Clearing Prices ($ per MW-day)	Actual Auction Results Cleared UCAP (MW)	Scenario Clearing Prices ($ per MW-day)	Scenario Cleared UCAP (MW)
RTO	Annual	$34.13	144,396.5	$24.13	144,724.5
	Summer	$34.13	474.1	$24.13	474.1
	Winter	$34.13	474.1	$24.13	474.1
RTO Total			144,870.6		145,198.6
MAAC	Annual	$49.49	62,900.1	$61.84	64,712.3
	Summer	$49.49	29.3	$61.84	29.3
	Winter	$49.49	29.3	$61.84	29.3
MAAC Total			62,929.4		64,741.6
DPL South	Annual	$69.95	1,324.0	$69.95	1,324.0
	Summer	$69.95	0.0	$69.95	0.0
	Winter	$69.95	0.0	$69.95	0.0
DPL South Total			1,324.0		1,324.0
BGE	Annual	$69.95	2,416.0	$69.95	2,416.0
	Summer	$69.95	0.0	$69.95	0.0
	Winter	$69.95	0.0	$69.95	0.0
BGE Total			2,416.0		2,416.0

Table 33 Impact of overstated intermittent capacity: 2023/2024 RPM Base Residual Auction

Scenario 6

		Actual Auction Results		Adjusted Intermittent MW	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$34.13	144,396.5	$35.40	144,356.9
	Summer	$34.13	474.1	$35.40	472.0
	Winter	$34.13	474.1	$35.40	472.0
RTO Total			144,870.6		144,828.9
MAAC	Annual	$49.49	62,900.1	$50.46	62,883.0
	Summer	$49.49	42.5	$50.46	29.3
	Winter	$49.49	29.3	$50.46	29.3
MAAC Total			62,929.4		62,912.3
DPL South	Annual	$69.95	1,324.0	$69.95	1,324.0
	Summer	$69.95	0.0	$69.95	0.0
	Winter	$69.95	0.0	$69.95	0.0
DPL South Total			1,324.0		1,324.0
BGE	Annual	$69.95	2,416.0	$69.95	2,416.0
	Summer	$69.95	0.6	$69.95	0.0
	Winter	$69.95	0.0	$69.95	0.0
BGE Total			2,416.0		2,416.0

Table 34 DR and EE statistics by LDA: 2022/2023 and 2023/2024 RPM Base Residual Auctions

		2022/2023 BRA			2023/2024 BRA			Change					
								Offered ICAP		Offered UCAP		Cleared UCAP	
LDA	Resource Type	Offered ICAP (MW)	Offered UCAP (MW)	Cleared UCAP (MW)	Offered ICAP (MW)	Offered UCAP (MW)	Cleared UCAP (MW)	MW	Percent	MW	Percent	MW	Percent
RTO	DR	9,584.4	10,411.4	8,710.3	9,299.6	10,135.7	8,115.2	(284.8)	(3.0%)	(275.7)	(2.6%)	(595.1)	(6.8%)
RTO	EE	4,542.2	4,933.2	4,694.1	4,905.5	5,346.8	5,346.8	363.3	8.0%	413.6	8.4%	652.7	13.9%
MAAC	DR	2,787.7	3,027.2	2,678.4	2,826.8	3,080.1	2,403.9	39.2	1.4%	53.0	1.8%	(274.4)	(10.2%)
MAAC	EE	1,792.9	1,946.2	1,942.1	1,996.5	2,176.0	2,176.0	203.6	11.4%	229.8	11.8%	233.9	12.0%
EMAAC	DR	1,176.7	1,277.4	1,082.8	1,182.2	1,288.4	975.9	5.5	0.5%	11.0	0.9%	(106.9)	(9.9%)
EMAAC	EE	990.5	1,075.1	1,073.6	1,072.0	1,168.4	1,168.4	81.5	8.2%	93.3	8.7%	94.8	8.8%
SWMAAC	DR	406.0	441.1	403.4	406.5	442.6	336.1	0.5	0.1%	1.6	0.4%	(67.2)	(16.7%)
SWMAAC	EE	424.5	461.1	458.5	489.8	533.9	533.9	65.3	15.4%	72.8	15.8%	75.3	16.4%
DPL South	DR	47.0	51.0	48.4	49.4	53.8	52.2	2.4	5.1%	2.8	5.5%	3.8	7.9%
DPL South	EE	45.8	49.6	49.6	47.0	51.2	51.2	1.2	2.6%	1.6	3.2%	1.6	3.2%
PSEG	DR	361.9	393.0	294.6	365.0	398.0	272.7	3.1	0.9%	5.0	1.3%	(21.9)	(7.4%)
PSEG	EE	347.4	377.0	375.6	349.4	380.9	380.9	2.0	0.6%	3.8	1.0%	5.2	1.4%
PSEG North	DR	111.0	120.6	93.8	158.1	172.3	126.1	47.1	42.4%	51.7	42.9%	32.3	34.4%
PSEG North	EE	165.5	179.5	178.8	161.1	175.6	175.6	(4.4)	(2.6%)	(3.9)	(2.2%)	(3.2)	(1.8%)
Pepco	DR	234.6	255.0	240.8	212.0	230.7	167.7	(22.6)	(9.6%)	(24.2)	(9.5%)	(73.0)	(30.3%)
Pepco	EE	240.7	261.6	259.0	254.7	277.6	277.6	14.0	5.8%	16.1	6.1%	18.6	7.2%
ATSI	DR	1,035.4	1,124.8	924.1	1,009.2	1,100.1	851.5	(26.2)	(2.5%)	(24.7)	(2.2%)	(72.6)	(7.9%)
ATSI	EE	378.7	411.4	410.4	385.7	420.3	420.3	7.0	1.8%	8.9	2.2%	10.0	2.4%
ATSI Cleveland	DR	243.4	264.5	166.5	204.1	222.4	162.8	(39.3)	(16.1%)	(42.1)	(15.9%)	(3.7)	(2.2%)
ATSI Cleveland	EE	38.3	41.4	41.4	39.4	42.9	42.9	1.1	2.9%	1.5	3.7%	1.5	3.7%
ComEd	DR	1,660.8	1,804.6	1,555.5	1,504.7	1,640.3	1,286.9	(156.1)	(9.4%)	(164.4)	(9.1%)	(268.7)	(17.3%)
ComEd	EE	777.8	845.1	656.8	815.5	888.8	888.8	37.7	4.8%	43.7	5.2%	232.0	35.3%
BGE	DR	171.4	186.1	162.6	194.5	211.9	168.4	23.1	13.5%	25.8	13.9%	5.8	3.6%
BGE	EE	183.8	199.6	199.6	235.1	256.3	256.3	51.3	27.9%	56.7	28.4%	56.7	28.4%
PPL	DR	658.1	715.1	661.7	657.3	716.2	583.4	(0.8)	(0.1%)	1.1	0.2%	(78.3)	(11.8%)
PPL	EE	216.1	234.7	234.7	260.1	283.5	283.5	44.0	20.3%	48.9	20.8%	48.9	20.8%
DAY	DR	236.3	256.5	210.5	240.7	262.4	209.3	4.4	1.9%	5.9	2.3%	(1.2)	(0.6%)
DAY	EE	85.2	92.4	91.3	85.3	92.9	92.9	0.1	0.1%	0.5	0.6%	1.6	1.8%
DEOK	DR	218.3	237.0	185.1	202.4	220.3	175.4	(15.9)	(7.3%)	(16.7)	(7.0%)	(9.7)	(5.2%)
DEOK	EE	134.9	146.5	143.0	142.6	155.4	155.4	7.6	5.7%	8.9	6.1%	12.4	8.7%

Table 35 Impact of demand resources: 2023/2024 RPM Base Residual Auction Scenario 7

		Actual Auction Results		No Offers for DR	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$34.13	144,396.5	$74.26	143,242.5
	Summer	$34.13	474.1	$74.26	297.0
	Winter	$34.13	474.1	$74.26	297.0
RTO Total			144,870.6		143,539.5
MAAC	Annual	$49.49	62,900.1	$74.26	62,772.0
	Summer	$49.49	43.9	$74.26	28.9
	Winter	$49.49	29.3	$74.26	28.9
MAAC Total			62,929.4		62,800.9
EMAAC	Annual	$49.49	30,097.5	$93.65	29,659.1
	Summer	$49.49	0.0	$93.65	0.0
	Winter	$49.49	0.0	$93.65	0.0
EMAAC Total			30,097.5		29,659.1
DPL South	Annual	$69.95	1,324.0	$93.65	1,330.9
	Summer	$69.95	0.0	$93.65	0.0
	Winter	$69.95	0.0	$93.65	0.0
DPL South Total			1,324.0		1,330.9
BGE	Annual	$69.95	2,416.0	$74.26	2,381.6
	Summer	$69.95	0.0	$74.26	0.0
	Winter	$69.95	0.0	$74.26	0.0
BGE Total			2,416.0		2,381.6

Table 36 Impact of EE: 2023/2024 RPM Base Residual Auction

Scenario 8

		Actual Auction Results		No Offers for EE and EE Addback Removed	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$34.13	144,396.5	$34.13	139,174.4
	Summer	$34.13	474.1	$34.13	224.1
	Winter	$34.13	474.1	$34.13	224.1
RTO Total			144,870.6		139,398.5
MAAC	Annual	$49.49	62,900.1	$49.49	60,715.9
	Summer	$49.49	29.3	$49.49	15.4
	Winter	$49.49	29.3	$49.49	15.4
MAAC Total			62,929.4		60,731.3
DPL South	Annual	$69.95	1,324.0	$69.95	1,272.8
	Summer	$69.95	0.0	$69.95	0.0
	Winter	$69.95	0.0	$69.95	0.0
DPL South Total			1,324.0		1,272.8
BGE	Annual	$69.95	2,416.0	$69.95	2,159.0
	Summer	$69.95	0.0	$69.95	0.0
	Winter	$69.95	0.0	$69.95	0.0
BGE Total			2,416.0		2,159.0

Table 37 Impact of price responsive demand (PRD): 2023/2024 RPM Base Residual Auction

Scenario 9

		Actual Auction Results		No PRD Offers	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$34.13	144,396.5	$34.13	144,652.5
	Summer	$34.13	474.1	$34.13	474.1
	Winter	$34.13	474.1	$34.13	474.1
RTO Total			144,870.6		145,126.6
MAAC	Annual	$49.49	62,900.1	$49.49	63,156.3
	Summer	$49.49	29.3	$49.49	29.3
	Winter	$49.49	29.3	$49.49	29.3
MAAC Total			62,929.4		63,185.6
DPL South	Annual	$69.95	1,324.0	$69.95	1,340.8
	Summer	$69.95	0.0	$69.95	0.0
	Winter	$69.95	0.0	$69.95	0.0
DPL South Total			1,324.0		1,340.8
BGE	Annual	$69.95	2,416.0	$69.95	2,510.8
	Summer	$69.95	0.0	$69.95	0.0
	Winter	$69.95	0.0	$69.95	0.0
BGE Total			2,416.0		2,510.8

Table 38 Impact of seasonal products: 2023/2024 RPM Base Residual Auction Scenario 10

		Actual Auction Results		Annual Only	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$34.13	144,396.5	$37.00	144,526.4
	Summer	$34.13	474.1	$37.00	0.0
	Winter	$34.13	474.1	$37.00	0.0
RTO Total			144,870.6		144,526.4
MAAC	Annual	$49.49	62,900.1	$49.49	62,884.8
	Summer	$49.49	29.3	$49.49	0.0
	Winter	$49.49	29.3	$49.49	0.0
MAAC Total			62,929.4		62,884.8
DPL South	Annual	$69.95	1,324.0	$69.95	1,324.0
	Summer	$69.95	0.0	$69.95	0.0
	Winter	$69.95	0.0	$69.95	0.0
DPL South Total			1,324.0		1,324.0
BGE	Annual	$69.95	2,416.0	$69.95	2,414.5
	Summer	$69.95	0.0	$69.95	0.0
	Winter	$69.95	0.0	$69.95	0.0
BGE Total			2,416.0		2,414.5

Table 39 Impact of seasonal matching across LDAs: 2023/2024 RPM Base Residual Auction

Scenario 11

		Actual Auction Results		No Matched Seasonal Offers Across LDAs	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$34.13	144,396.5	$34.13	144,417.2
	Summer	$34.13	474.1	$34.13	396.3
	Winter	$34.13	474.1	$34.13	396.3
RTO Total			144,870.6		144,813.5
MAAC	Annual	$49.49	62,900.1	$49.49	62,884.8
	Summer	$49.49	29.3	$49.49	2.7
	Winter	$49.49	29.3	$49.49	2.7
MAAC Total			62,929.4		62,887.5
DPL South	Annual	$69.95	1,324.0	$69.95	1,324.0
	Summer	$69.95	0.0	$69.95	0.0
	Winter	$69.95	0.0	$69.95	0.0
DPL South Total			1,324.0		1,324.0
BGE	Annual	$69.95	2,416.0	$69.95	2,414.5
	Summer	$69.95	0.0	$69.95	0.0
	Winter	$69.95	0.0	$69.95	0.0
BGE Total			2,416.0		2,414.5

Table 40 RPM imports: 2007/2008 through 2023/2024 RPM Base Residual Auctions

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

Table 41 Impact of capacity imports: 2023/2024 RPM Base Residual Auction Scenario 12

		Actual Auction Results		No Capcity Imports	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$34.13	144,396.5	$37.23	144,294.7
	Summer	$34.13	474.1	$37.23	474.1
	Winter	$34.13	474.1	$37.23	474.1
RTO Total			144,870.6		144,768.8
MAAC	Annual	$49.49	62,900.1	$49.49	62,900.2
	Summer	$49.49	29.3	$49.49	29.3
	Winter	$49.49	29.3	$49.49	29.3
MAAC Total			62,929.4		62,929.5
DPL South	Annual	$69.95	1,324.0	$69.95	1,324.0
	Summer	$69.95	0.0	$69.95	0.0
	Winter	$69.95	0.0	$69.95	0.0
DPL South Total			1,324.0		1,324.0
BGE	Annual	$69.95	2,416.0	$69.95	2,416.0
	Summer	$69.95	0.0	$69.95	0.0
	Winter	$69.95	0.0	$69.95	0.0
BGE Total			2,416.0		2,416.0

Table 42 Impact of Combined Scenarios 6, 7, 8, 9, 10, 12: 2023/2024 RPM Base Residual Auction

Scenario 13

		Actual Auction Results		No Offers from DR, EE, PRD, Seasonal, External Resources and Adjusted Intermittent MW	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$34.13	144,396.5	$97.48	137,577.6
	Summer	$34.13	474.1	$97.48	0.0
	Winter	$34.13	474.1	$97.48	0.0
RTO Total			144,870.6		137,577.6
MAAC	Annual	$49.49	62,900.1	$97.48	62,140.9
	Summer	$49.49	29.3	$97.48	0.0
	Winter	$49.49	29.3	$97.48	0.0
MAAC Total			62,929.4		62,140.9
EMAAC	Annual	$49.49	30,097.5	$98.51	28,479.5
	Summer	$49.49	0.0	$98.51	0.0
	Winter	$49.49	0.0	$98.51	0.0
EMAAC Total			30,097.5		28,479.5
DPL South	Annual	$69.95	1,324.0	$98.51	1,274.8
	Summer	$69.95	0.0	$98.51	0.0
	Winter	$69.95	0.0	$98.51	0.0
DPL South Total			1,324.0		1,274.8
BGE	Annual	$69.95	2,416.0	$97.48	2,279.0
	Summer	$69.95	0.0	$97.48	0.0
	Winter	$69.95	0.0	$97.48	0.0
BGE Total			2,416.0		2,279.0

Table 43 Impact of nuclear offers: 2023/2024 RPM Base Residual Auction

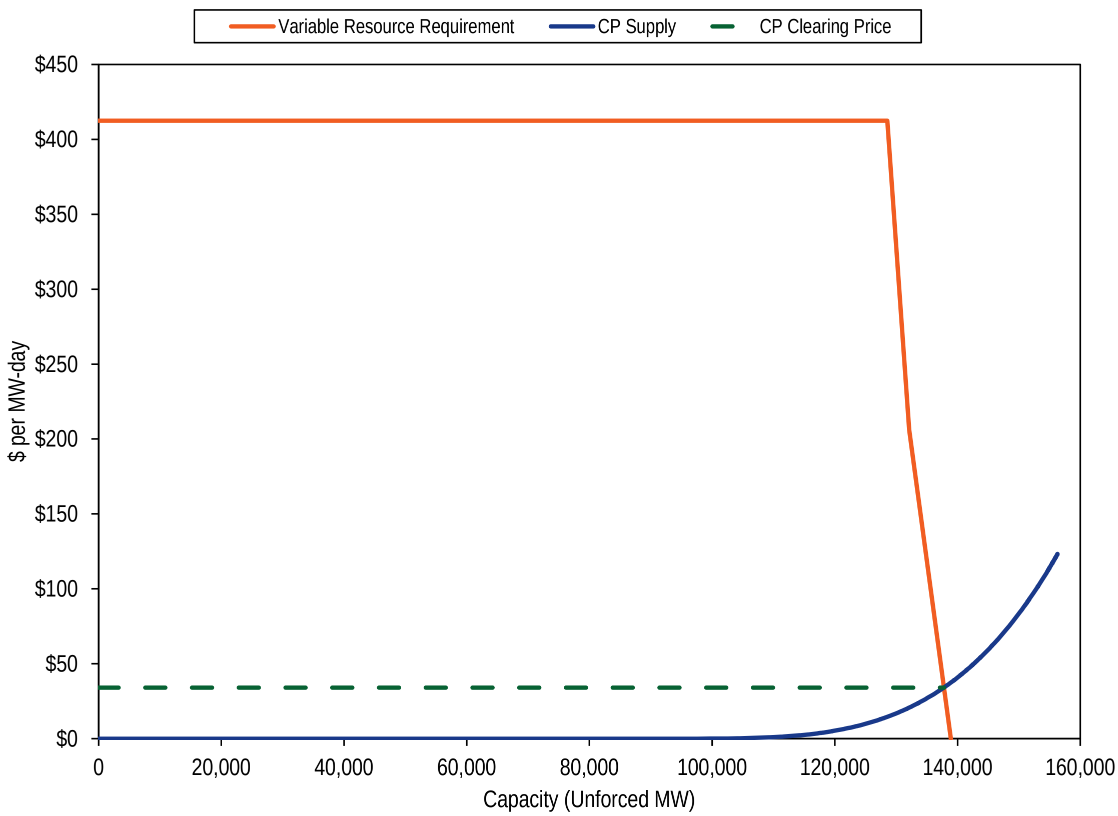
Scenario 14

		Actual Auction Results		All Nuclear Offers at $0 per MW-day	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$34.13	144,396.5	$34.13	144,396.4
	Summer	$34.13	474.1	$34.13	474.1
	Winter	$34.13	474.1	$34.13	474.1
RTO Total			144,870.6		144,870.5
MAAC	Annual	$49.49	62,900.1	$49.49	62,900.2
	Summer	$49.49	29.3	$49.49	29.3
	Winter	$49.49	29.3	$49.49	29.3
MAAC Total			62,929.4		62,929.5
DPL South	Annual	$69.95	1,324.0	$69.95	1,324.0
	Summer	$69.95	0.0	$69.95	0.0
	Winter	$69.95	0.0	$69.95	0.0
DPL South Total			1,324.0		1,324.0
BGE	Annual	$69.95	2,416.0	$69.95	2,416.0
	Summer	$69.95	0.0	$69.95	0.0
	Winter	$69.95	0.0	$69.95	0.0
BGE Total			2,416.0		2,416.0

Table 44 Impact of combined scenarios 2, 6, 7, 12: 2023/2024 RPM Base Residual Auction Scenario 15

		Actual Auction Results		Combined scenarios 2, 6, 7, 12	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$34.13	144,396.5	$55.85	140,301.2
	Summer	$34.13	474.1	$55.85	294.9
	Winter	$34.13	474.1	$55.85	294.9
RTO Total			144,870.6		140,596.1
MAAC	Annual	$49.49	62,900.1	$55.85	61,868.2
	Summer	$49.49	29.3	$55.85	28.9
	Winter	$49.49	29.3	$55.85	28.9
MAAC Total			62,929.4		61,897.1
DPL South	Annual	$69.95	1,324.0	$69.95	1,245.7
	Summer	$69.95	0.0	$69.95	0.0
	Winter	$69.95	0.0	$69.95	0.0
DPL South Total			1,324.0		1,245.7
BGE	Annual	$69.95	2,416.0	$69.95	2,242.5
	Summer	$69.95	0.0	$69.95	0.0
	Winter	$69.95	0.0	$69.95	0.0
BGE Total			2,416.0		2,242.5

Figure 2 RTO market supply/demand curves: 2023/2024 RPM Base Residual Auction[183] [184]



MAAC LDA Market Results

Table 45 shows total MAAC LDA offer data for the 2023/2024 RPM Base Residual Auction. Total internal MAAC LDA unforced capacity, excluding generation winter capacity, of

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

184 The VRR curve excludes incremental demand which cleared in MAAC, DPL South, and BGE.

71,029.8 MW includes all Generation Capacity Resources, Demand Resources, and Energy Efficiency Resources that qualified as PJM Capacity Resources, excludes external units, and also includes owners' modifications to ICAP ratings. As shown in Table 10, MAAC LDA unforced internal capacity decreased 2,608.7 MW from 73,638.5 MW in the 2022/2023 BRA as a result of net generation capacity modifications (-2,650.2 MW), net DR modifications (227.0 MW), and net EE modifications (221.2 MW), the EFORd effect due to higher sell offer EFORds (-423.9 MW), and the DR and EE effect due to a higher load management UCAP conversion factor (17.2 MW). As shown in Table 12, total internal MAAC unforced winter capacity decreased by 121.6 MW for November through April of the 2023/2024 Delivery Year.

All imports offered in the auction from areas external to PJM are modeled as supply in the rest of RTO.[185] Total internal MAAC LDA capacity was reduced by FRR commitments of 51.3 MW, resulting in MAAC LDA RPM capacity of 71,006.3 MW. RPM capacity was reduced by 674.0 MW of exports, 0.0 MW of FRR optional volumes not offered, 405.5 MW excused from the RPM must offer requirement, 0.0 MW of Planned Generation Capacity Resources which were not subject to the RPM must offer requirement, and 945.6 MW of intermittent resources and 671.4 MW of capacity storage resources which were not subject to the CP must offer requirement. The excused Existing Generation Capacity Resources were the result of plans for retirement (405.5 MW). Subtracting 464.7 MW of DR and EE not offered and 13.2 MW of unoffered generation winter capacity resulted in available unforced capacity in MAAC LDA of 67,831.9 MW.[186] After accounting for these exceptions, all capacity resources in MAAC were offered in the RPM Auction.

The MAAC LDA import limit was a binding constraint in the 2023/2024 BRA. Of the 62,945.1 MW cleared in MAAC LDA, 55,588.3 MW were cleared in the RTO before MAAC LDA became constrained. Once the constraint was binding, based on the 6,381.0 MW CETL value, only the incremental supply located in MAAC LDA was available to meet the incremental demand in the LDA. Of the incremental supply, 7,356.8 MW cleared, which resulted in a clearing price for Capacity Performance Resources of $49.49 per MW-day, as shown in Figure 4. The clearing price was determined by the intersection of the incremental supply and VRR curve.

185 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).

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

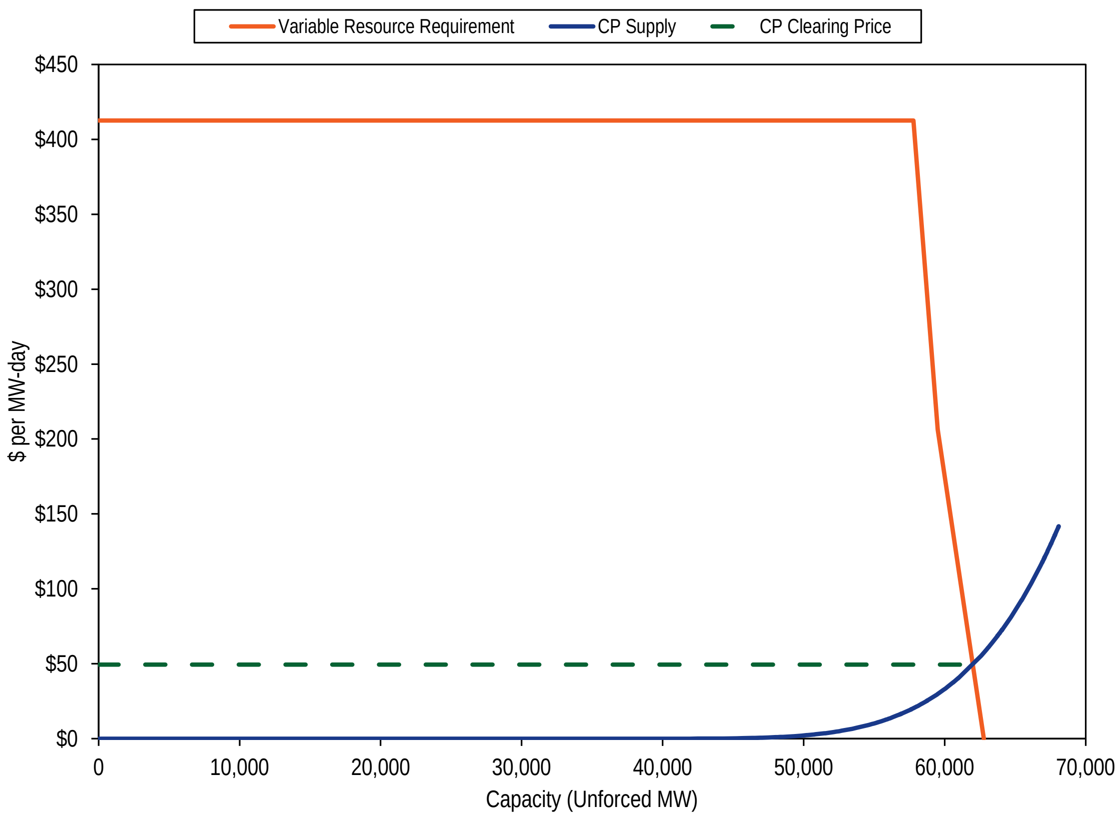
As shown in Table 17, the 60,746.9 MW of cleared generation and DR for MAAC LDA and 6,381.0 MW CETL resulted in a net excess of 3,565.1 MW.

Table and Figure for MAAC LDA

Table 45 MAAC LDA offer statistics: 2023/2024 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	68,177.4	65,309.0		
DR capacity	3,221.2	3,510.0		
EE capacity	2,028.4	2,210.8		
Generation winter capacity	27.8	27.8		
Total internal MAAC LDA capacity	73,454.8	71,057.6		
FRR	(52.1)	(51.3)		
Imports	0.0	0.0		
RPM capacity	73,402.7	71,006.3		
Exports	(674.0)	(674.0)		
FRR optional	0.0	0.0		
Excused Existing Generation Capacity Resources	(462.5)	(405.5)		
Unoffered Planned Generation Capacity Resources	0.0	0.0		
Unoffered Intermittent Resources	(947.0)	(945.6)		
Unoffered Capacity Storage Resources	(671.4)	(671.4)		
Unoffered generation winter capacity	(13.2)	(13.2)		
Unoffered DR and EE	(426.3)	(464.7)		
Available	70,208.3	67,831.9	100.0%	100.0%
Generation offered	65,385.0	62,575.8	93.1%	92.3%
DR offered	2,826.8	3,080.1	4.0%	4.5%
EE offered	1,996.5	2,176.0	2.8%	3.2%
Total offered	70,208.3	67,831.9	100.0%	100.0%
Unoffered Existing Generation Capacity Resources	0.0	0.0	0.0%	0.0%

Figure 3 MAAC LDA market supply/demand curves: 2023/2024 RPM Base Residual Auction[187]



DPL South LDA Market Results

Table 46 shows total DPL South LDA offer data for the 2023/2024 RPM Base Residual Auction. Total internal DPL South LDA unforced capacity, excluding generation winter capacity, of 1,785.6 MW includes all Generation Capacity Resources, Demand Resources, and Energy Efficiency Resources that qualified as PJM Capacity Resources, excludes external units, and also includes owners' modifications to ICAP ratings. As shown in Table 10, DPL South LDA unforced internal capacity increased 56.2 MW from 1,729.4 MW in the 2022/2023 BRA as a result of net generation capacity modifications (43.7 MW), net DR modifications (13.2 MW), and net EE modifications (1.5 MW), the EFORd effect due to higher sell offer EFORds (-2.5 MW), and the DR and EE effect due to a higher load management UCAP conversion factor (0.3 MW). As shown in Table 12, total internal DPL

187 The VRR curve is reduced by the CETL and incremental demand which cleared in DPL South and BGE.

South unforced winter capacity increased by 0.0 MW for November through April of the 2023/2024 Delivery Year.

All imports offered in the auction from areas external to PJM are modeled as supply in the rest of RTO.[188] Total internal DPL South LDA capacity was reduced by FRR commitments of 0.0 MW, resulting in DPL South LDA RPM capacity of 1,785.6 MW. RPM capacity was reduced by 0.0 MW of exports, 0.0 MW of FRR optional volumes not offered, 368.4 MW excused from the RPM must offer requirement, 0.0 MW of Planned Generation Capacity Resources which were not subject to the RPM must offer requirement, and 20.3 MW of intermittent resources and 0.0 MW of capacity storage resources which were not subject to the CP must offer requirement. The excused Existing Generation Capacity Resources were the result of plans for retirement (368.4 MW). Subtracting 12.2 MW of DR and EE not offered and 0.0 MW of unoffered generation winter capacity resulted in available unforced capacity in DPL South LDA of 1,384.7 MW.[189] After accounting for these exceptions, all capacity resources in DPL South were offered in the RPM Auction.

The DPL South LDA import limit was a binding constraint in the 2023/2024 BRA. Of the 1,324.0 MW cleared in DPL South LDA, 1,257.8 MW were cleared in the MAAC LDA before DPL South LDA became constrained. Once the constraint was binding, based on the 2,008.0 MW CETL value, only the incremental supply located in DPL South LDA was available to meet the incremental demand in the LDA. Of the incremental supply, 66.2 MW cleared, which resulted in a clearing price for Capacity Performance Resources of $69.95 per MW-day, as shown in Figure 4. The clearing price was determined by the intersection of the incremental supply and VRR curve.

As shown in Table 17, the 1,272.8 MW of cleared generation and DR for DPL South LDA and 2,008.0 MW CETL resulted in a net excess of 156.6 MW.

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188 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).

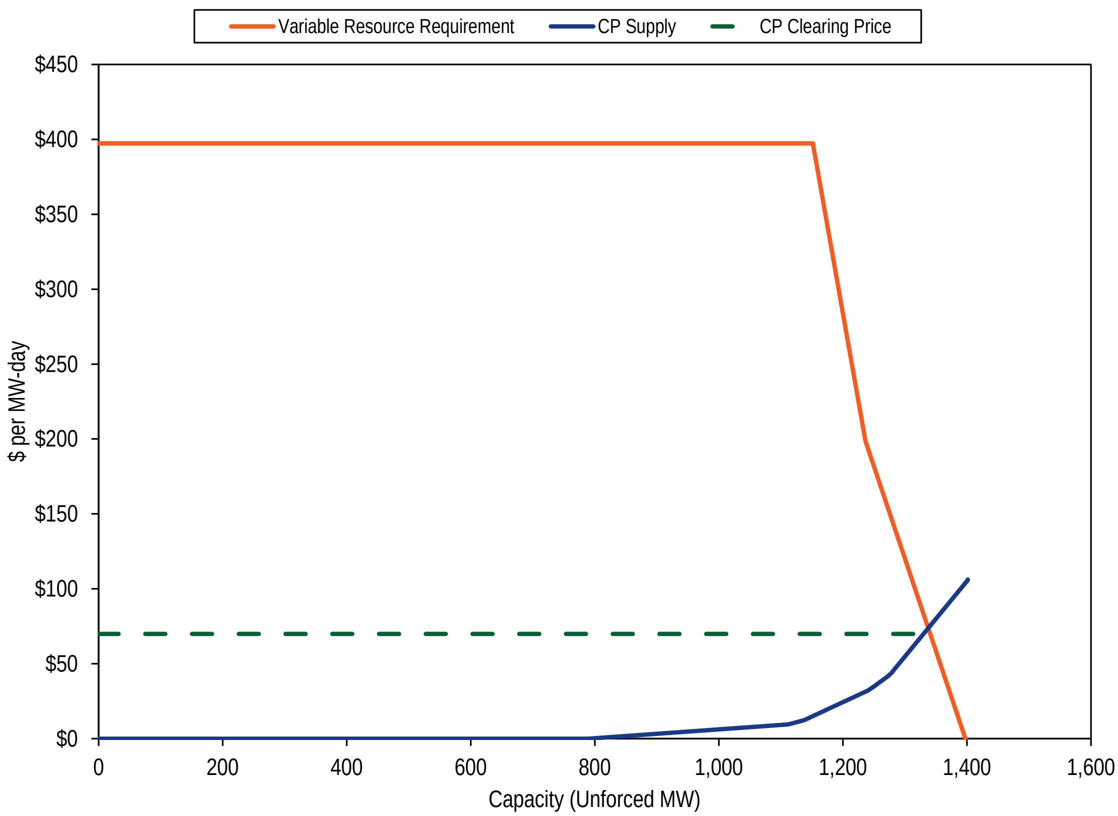
189 Unoffered DR and EE MW include PJM approved DR and EE plans that were not offered in the auction.

Table and Figure for DPL South LDA

Table 46 EMAAC LDA offer statistics: 2023/2024 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	1,753.2	1,668.4		
DR capacity	60.6	66.0		
EE capacity	47.0	51.2		
Generation winter capacity	0.0	0.0		
Total internal DPL South LDA capacity	1,860.8	1,785.6		
FRR	0.0	0.0		
Imports	0.0	0.0		
RPM capacity	1,860.8	1,785.6		
Exports	0.0	0.0		
FRR optional	0.0	0.0		
Excused Existing Generation Capacity Resources	(410.0)	(368.4)		
Unoffered Planned Generation Capacity Resources	0.0	0.0		
Unoffered Intermittent Resources	(20.3)	(20.3)		
Unoffered Capacity Storage Resources	0.0	0.0		
Unoffered generation winter capacity	0.0	0.0		
Unoffered DR and EE	(11.2)	(12.2)		
Available	1,419.3	1,384.7	100.0%	100.0%
Generation offered	1,322.9	1,279.7	93.2%	92.4%
DR offered	49.4	53.8	3.5%	3.9%
EE offered	47.0	51.2	3.3%	3.7%
Total offered	1,419.3	1,384.7	100.0%	100.0%
Unoffered Existing Generation Capacity Resources	0.0	0.0	0.0%	0.0%

Figure 4 DPL South LDA market supply/demand curves: 2023/2024 RPM Base Residual Auction[190]



BGE LDA Market Results

Table 47 shows total BGE LDA offer data for the 2023/2024 RPM Base Residual Auction. Total internal BGE LDA unforced capacity, excluding generation winter capacity, of 2,915.6 MW includes all Generation Capacity Resources, Demand Resources, and Energy Efficiency Resources that qualified as PJM Capacity Resources, excludes external units, and also includes owners' modifications to ICAP ratings. As shown in Table 10, BGE LDA unforced internal capacity decreased 87.6 MW from 3,003.2 MW in the 2022/2023 BRA as a result of net generation capacity modifications (-119.0 MW), net DR modifications (29.7 MW), and net EE modifications (56.3 MW), the EFORd effect due to higher sell offer EFORds (-56.1 MW), and the DR and EE effect due to a higher load management UCAP conversion factor (1.5 MW). As shown in Table 12, total internal BGE unforced winter capacity increased by 0.0 MW for November through April of the 2023/2024 Delivery Year.

190 The VRR curve is reduced by the CETL.

All imports offered in the auction from areas external to PJM are modeled as supply in the rest of RTO.[191] Total internal BGE LDA capacity was reduced by FRR commitments of 0.0 MW, resulting in BGE LDA RPM capacity of 2,915.6 MW. RPM capacity was reduced by 0.0 MW of exports, 0.0 MW of FRR optional volumes not offered, 0.0 MW excused from the RPM must offer requirement, 0.0 MW of Planned Generation Capacity Resources which were not subject to the RPM must offer requirement, and 0.0 MW of intermittent resources and 0.0 MW of capacity storage resources which were not subject to the CP must offer requirement. Subtracting 24.1 MW of DR and EE not offered and 0.0 MW of unoffered generation winter capacity resulted in available unforced capacity in BGE LDA of 2,891.5 MW.[192] After accounting for these exceptions, all capacity resources in BGE LDA were offered in the RPM Auction.

The BGE LDA import limit was a binding constraint in the 2023/2024 BRA. Of the 2,416.8 MW cleared in BGE LDA, 1,295.2 MW were cleared in the MAAC LDA before BGE LDA became constrained. Once the constraint was binding, based on the 5,615.0 MW CETL value, only the incremental supply located in BGE LDA was available to meet the incremental demand in the LDA. Of the incremental supply, 1,121.6 MW cleared, which resulted in a clearing price for Capacity Performance Resources of $69.95 per MW-day, as shown in Figure 5. The clearing price was determined by the intersection of the incremental supply and VRR curve.

As shown in Table 17, the 2,159.8 MW of cleared generation and DR for BGE LDA and 5,615.0 MW CETL resulted in a net excess of 347.6 MW.

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191 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).

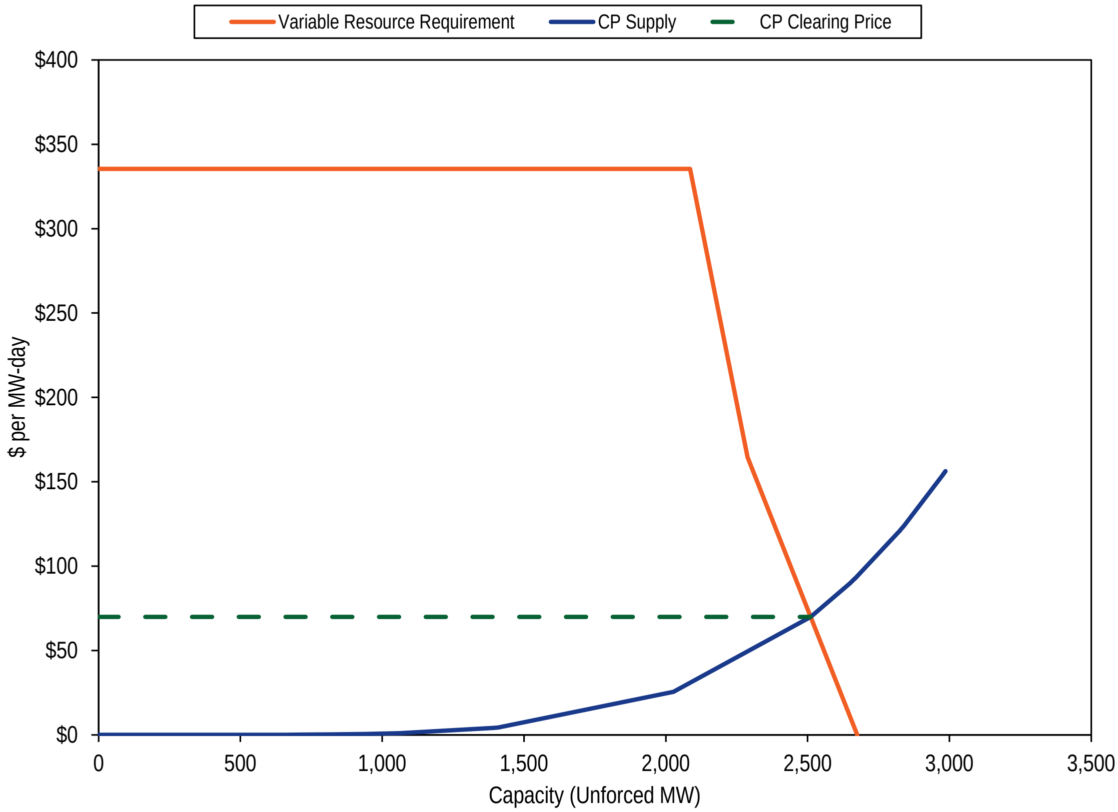
192 Unoffered DR and EE MW include PJM approved DR and EE plans that were not offered in the auction.

Table and Figure for BGE LDA

Table 47 BGE LDA offer statistics: 2023/2024 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	2,629.9	2,423.4		
DR capacity	215.9	235.2		
EE capacity	235.8	257.0		
Generation winter capacity	0.0	0.0		
Total internal BGE LDA capacity	3,081.6	2,915.6		
FRR	0.0	0.0		
Imports	0.0	0.0		
RPM capacity	3,081.6	2,915.6		
Exports	0.0	0.0		
FRR optional	0.0	0.0		
Excused Existing Generation Capacity Resources	0.0	0.0		
Unoffered Planned Generation Capacity Resources	0.0	0.0		
Unoffered Intermittent Resources	0.0	0.0		
Unoffered Capacity Storage Resources	0.0	0.0		
Unoffered generation winter capacity	0.0	0.0		
Unoffered DR and EE	(22.1)	(24.1)		
Available	3,059.5	2,891.5	100.0%	100.0%
Generation offered	2,629.9	2,423.4	86.0%	83.8%
DR offered	194.5	211.9	6.4%	7.3%
EE offered	235.1	256.3	7.7%	8.9%
Total offered	3,059.5	2,891.6	100.0%	100.0%
Unoffered Existing Generation Capacity Resources	0.0	0.0	0.0%	0.0%

Figure 5 BGE LDA market supply/demand curves: 2023/2024 RPM Base Residual Auction[193]



193 The VRR curve is reduced by the CETL.

Attachment A

Clearing Algorithm for RPM Base Residual Auction

The clearing of the RPM Base Residual Auction (BRA) uses a mixed integer optimization algorithm. The purpose of the algorithm is to minimize the cost of procuring unforced capacity given all applicable requirements and constraints, including transmission limits between LDAs, restrictions on coupled sell offers and restrictions specified in credit limited offers.[1] The optimization algorithm calculates clearing prices, which are derived from the shadow prices of the binding resource constraints.

In the BRA, the locational requirement to purchase capacity takes the form of a downward sloping piece-wise linear demand curve called the Variable Resource Requirement (VRR) curve. The VRR curve defines the maximum price for a given level of capacity procurement within each of the constrained LDAs. In the nested LDA structure, the capacity procured towards meeting a child LDA's Variable Resource Requirement also satisfies the nested parent LDA's Variable Resource Requirement. A part of the capacity procured for the parent LDA may be transferred to the child LDA up to the defined Capacity Emergency Transfer Limit (CETL) between the parent LDA and the child LDA. For a child LDA, when a CETL constraint binds and limits imports from the parent LDA, higher priced offers that would not clear in an unconstrained market are required to meet demand in the child LDA. The result is a constrained price for the child LDA which is higher than the price for the parent LDA. Accordingly, the shadow price associated with this constraint, called the locational price adder, should accurately account for the additional cost of meeting the internal requirement for capacity. Implementing this constraint for a nested LDA structure, while preserving the linearity of the optimization problem, poses a particular computational challenge.

The RPM algorithm cooptimizes the cost of procuring a child LDA's and the parent LDA's capacity to meet their respective Variable Resource Requirements. Since the capacity procured for the child LDA jointly satisfies its own and its parent LDA's VRR, the parent LDA's VRR curve needs to be reconfigured to take into account the child LDA's cleared capacity. Any such reconfiguration may result in a different solution for the child LDA. In the RPM algorithm, the mixed integer optimization problem is solved iteratively, where after every iteration, the parent LDAs' VRR curves are reconfigured to reflect their respective child LDAs' cleared capacity. The process is repeated until an equilibrium point is reached. The method preserves the mixed integer feature of the optimization problem while allowing for incorporation of the resource constraints.

[1] OATT Attachment DD § 5.12(a).

Under this approach, the price adders are directly obtained as shadow prices of the import limit constraints. Prior to the 2017/2018 BRA, the price adders for annual and extended summer resources were obtained from the shadow prices associated with the respective binding constraints. Effective with the 2017/2018 BRA, PJM replaced the minimum requirements for Annual and Extended Summer DR products with limits on the maximum amount of Limited and Extended Summer DR products. As a result, effective with the 2017/2018 BRA, the price adder for Annual Resources is obtained as the shadow price of the import limit constraint for any constrained child LDA. The price decrements for Limited and Extended Summer DR products are obtained from the shadow prices associated with the respective binding maximum resource constraints. Effective for the 2018/2019 and the 2019/2020 Delivery Years, a Base Capacity Demand Resource and Energy Efficiency (DR/EE) Constraint and a Base Capacity Resource Constraint, replacing the Sub-Annual Resource Constraint and Limited Resource Constraint, are established for each modeled LDA. As a result, effective for the 2018/2019 and the 2019/2020 Delivery Years, the price adder for Capacity Performance Resources is obtained as the shadow price of the import limit constraint for any constrained child LDA. The price decrements for Base Capacity Resources and Base Capacity DR/EE are obtained from the shadow prices associated with the respective binding maximum resource constraints. Effective for 2020/2021 and subsequent delivery years, the Base Capacity Resource Constraint and the Base Capacity Demand Resource and Energy Efficiency (DR/EE) Constraint were eliminated since only Capacity Performance resources were allowed to offer in the BRA.

In the BRA, capacity market sellers are allowed to specify a minimum level of unforced capacity for any resource offered into the auction rather than a fully flexible offer. If any such inflexible offers are marginal or close to marginal, PJM's market solution algorithm relaxes the minimum level of those offers and re-solves the optimization, allowing those offers to clear below the specified minimum level. Any resource that, as a result, cleared at a MW level below the specified minimum level, is paid uplift for the difference between cleared MW and the minimum level, at the clearing price. The solution method does not consider the additional cost of uplift payments as part of the optimization objective. The alternative to clearing an inflexible offer will generally be the clearing of a higher priced offer to satisfy the applicable resource requirements without an uplift payment. In the MMU's approach, the RPM algorithm explicitly compares solutions with uplift against solutions without uplift payments to arrive at the optimal solution.

Possible Reasons for Differences between PJM and MMU Solutions

It is possible for the MMU's solution to the BRA optimization problem to differ from PJM's solution although these differences are usually small. The following are some of the reasons which may contribute to differences between the MMU's solution and PJM's solution:

1. Optimization Tolerance: All mixed integer programming solvers use numerical methods to determine the optimal solution. These methods are of finite arithmetic precision. Therefore, the search path and eventually the final solution depend on the chosen tolerance levels. In general, tighter tolerance levels are associated with longer computational times. One of the tolerance criteria used by mixed integer programming solvers is specified as a limit on the execution time. When execution time is a tolerance criterion, it is possible for solutions to diverge slightly, even with identical resource limit criteria, due to differences in the speed of the computers on which the solver is run.
2. Algorithm: The solution approach involves iteratively solving a mixed integer problem to locate the optimal solution given all the applicable business rules. The tolerance of the criteria used to evaluate feasible solutions in the iterative approach is also likely to affect the final solution. For example, using a slightly different criterion for the equilibrium point in the reconfiguration of the parent LDA's VRR curve could result in negligible impact on cleared quantities, but the impact on shadow prices and consequently marginal clearing prices could be substantial. The iterative approach where a sequence of the mixed integer problems are solved, contributes to the instability of the final solution.
3. Non-unique solution: It is possible for the BRA optimization problem to have non-unique solutions. Identical inputs could result in slightly different solutions with exactly the same objective value within the chosen tolerance levels each time the solution is calculated.

Comparison of PJM and MMU Solutions

The results of the 2023/2024 RPM Base Residual Auction conducted by PJM were replicated using the MMU's approach. The total MW cleared for every constrained nested LDA using the MMU's algorithm is identical to the corresponding total MW cleared under PJM's method. The total MW cleared for the entire RTO using the MMU's algorithm is identical to the total MW cleared under PJM's method. The clearing prices using the PJM's approach were identical to the clearing prices under MMU's method.

Recommendations for the RPM Market Clearing

The MMU recommends that PJM clear the capacity market based on nodal capacity resource locations and the characteristics of the transmission system consistent with the actual electrical facts of the grid. The current nested LDA structure used in the capacity market does not adequately represent all the capacity transfers that are feasible among LDAs. For example, under the current structure, any capacity transfer between the Dominion LDA, which is modeled within the Rest of the RTO LDA, and the Pepco LDA needs to pass through MAAC and SWMAAC LDAs, although Dominion and Pepco regions are linked by several transmission lines.

Absent a fully nodal capacity market clearing process, the MMU recommends that PJM use non-nested model with all LDAs and specify VRR curves for each LDA. 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.

The nested structure also contributes to an important inefficiency in the clearing of resources. Under the existing nested structure, every resource is eligible to satisfy the reliability requirement of the LDA where the resource is located and also all the higher level parent LDAs to which it belongs. For instance, a resource located within the PSEG North LDA can satisfy the reliability requirement of PSEG North, PSEG, EMAAC, MAAC and RTO. However, the LDA demand (VRR) curves are defined such that, in the optimization, any resource that satisfies the requirement of a higher level LDA yields a larger consumer surplus than clearing that resource in a lower level LDA. For example, a capacity resource located in the child LDA PSEG North always results in a higher or equal consumer surplus if it clears to meet the parent LDA PSEG's requirement, instead of clearing to satisfy PSEG North's requirement. The optimal clearing solution would satisfy the parent LDA's requirement while clearing fewer resources to satisfy the child LDA's requirement. As a result, the optimal clearing solution would satisfy the parent LDA's requirement while clearing fewer resources to satisfy the child LDA's requirement. As a result of this feature of the optimization model, a constraint is added to the model to force meeting the requirements of child LDAs before the requirements of parent LDAs. Without such constraints, the clearing process using a nested LDA model would produce implausible outcomes.

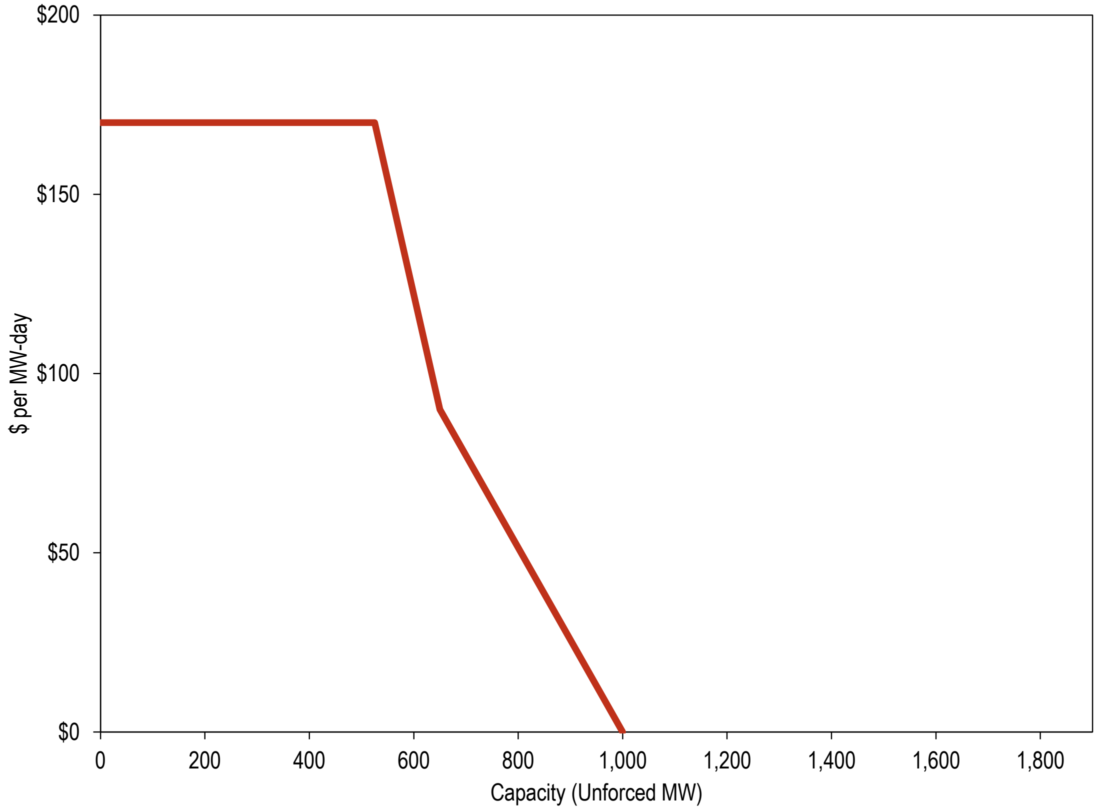
The MMU recommends improving the RPM solution method related to uplift payments. The MMU recommends changing the RPM solution method to explicitly incorporate the cost of uplift payments in the objective function.

Illustration of BRA Clearing Algorithm

The objective function in the auction optimization algorithm is to maximize the area between the RTO VRR curve and the supply curve from the origin to the clearing price while simultaneously satisfying the LDA import limits and minimum resource requirements. The objective ensures that the total cost of procurement is minimized while the highest offer cleared, bounded by the VRR curve, sets the clearing price. The auction clearing process is equivalent to choosing the price and quantity that maximize total welfare, where the VRR curve is the demand curve and capacity offers are the supply curve.

Figure 1 and Figure 2 show an example child VRR and parent VRR curves. To illustrate the price formation in the BRA, two example scenarios are presented. In the first scenario, a higher CETL is assumed between the parent LDA and the child LDA. In the second scenario, a lower CETL is assumed between the parent LDA and the child LDA. All other offers and parameters are identical in the two scenarios. In both scenarios, only one type of resource and only one requirement are considered.[2]

Figure 1 Variable resource requirement curve: child LDA



[2] For simplicity, the Base Capacity Resource Constraint and the Base Capacity Demand Resource Constraint are not included.

Figure 2 Nested variable resource requirement curve: parent LDA

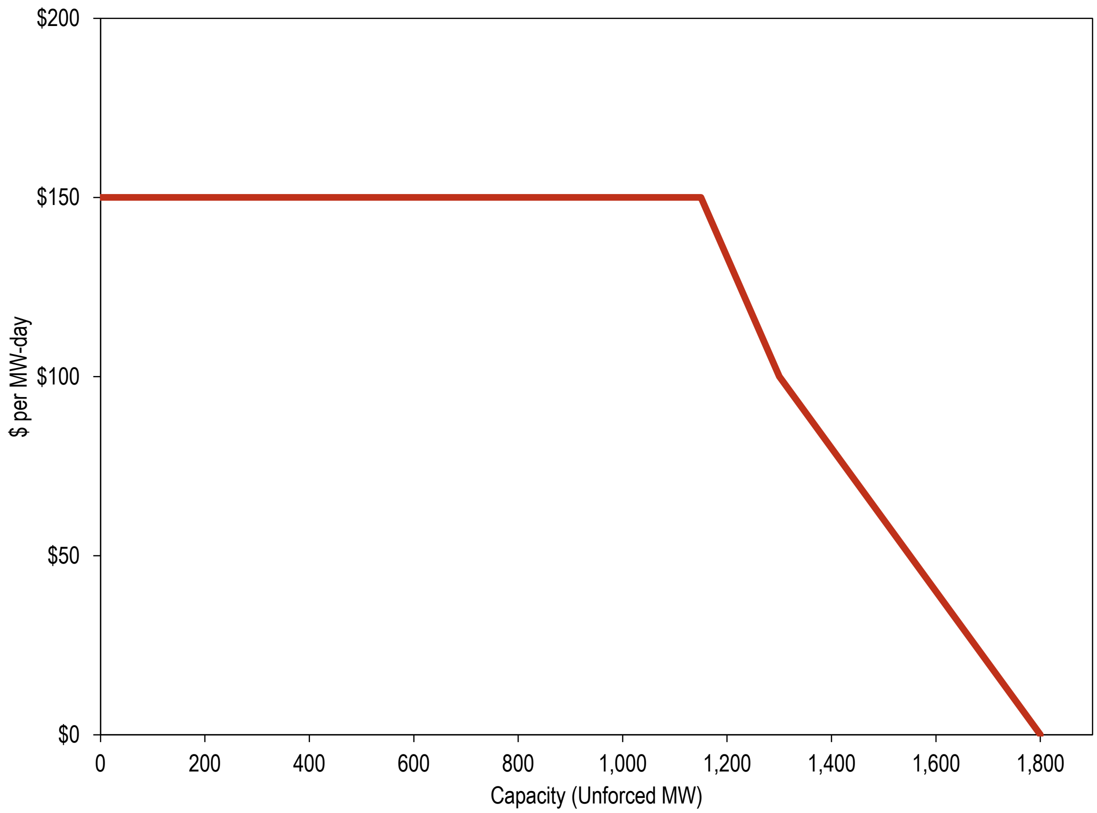


Figure 3 and Figure 4 illustrate the solution for the first scenario. Only 189.1 MW of the available 300 MW CETL is utilized. Therefore the CETL constraint is non-binding and out of merit offers are not needed to meet the child LDA's Variable Resource Requirement. The marginal clearing price for both the parent and child LDA is $120.00.

Figure 3 Optimal solution for scenario 1: child LDA

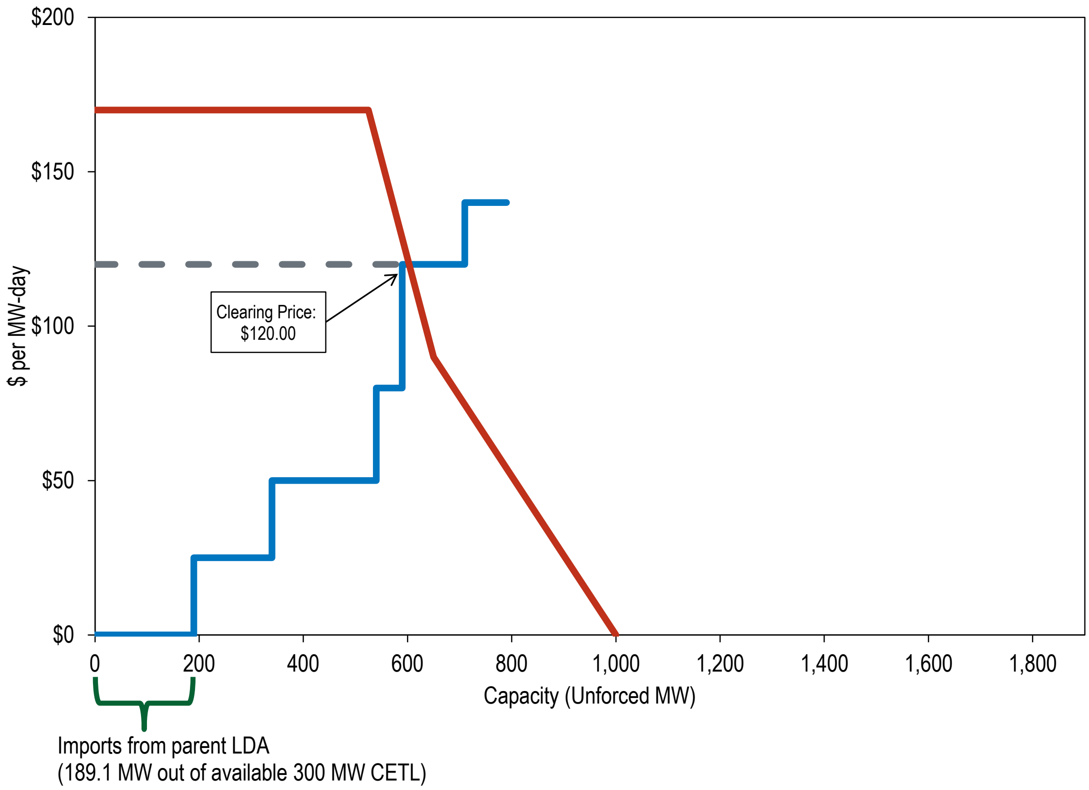


Figure 4 Optimal solution for scenario 1: Parent LDA

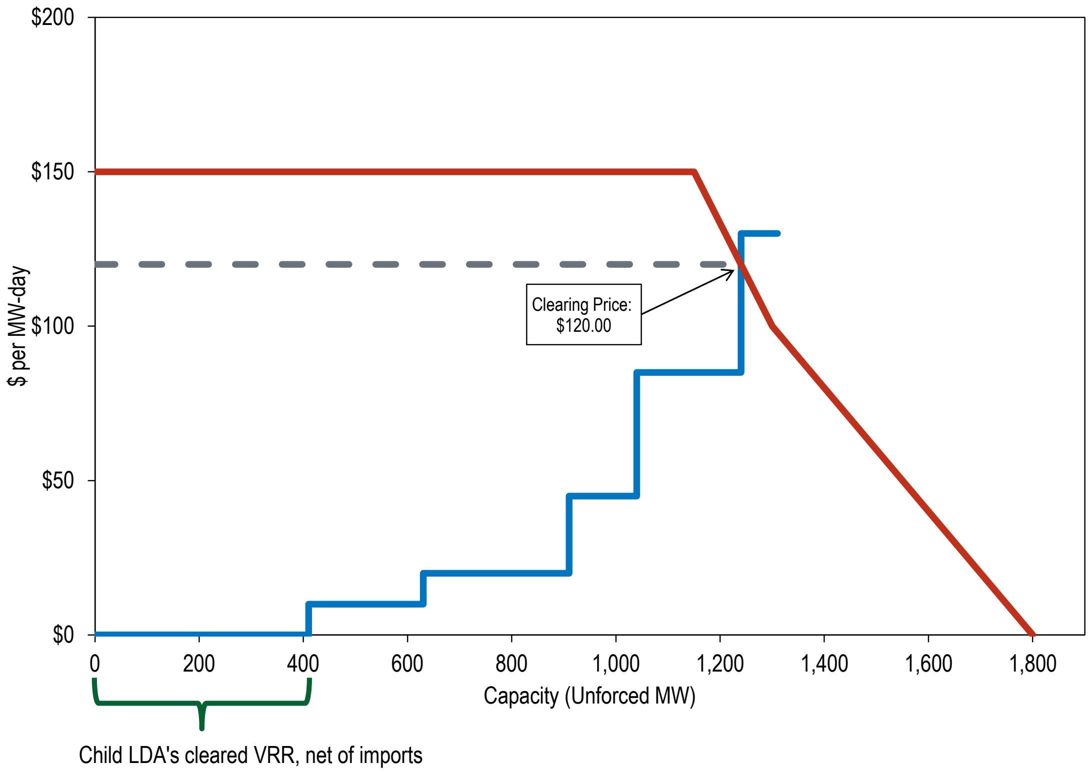


Figure 5 and Figure 6 illustrate the solution for the second scenario. The only difference between first and second scenarios is that the CETL is 150 MW in the second scenario compared to 300 MW in the first scenario. The solution shows that the entire 150 MW available is utilized by the child LDA to import capacity from the parent LDA. Out of merit, higher price offers, relative to the ones cleared for the parent LDA, are needed to meet the Variable Resource Requirement of the child LDA. The shadow price of the binding CETL constraint, $13.30 per MW-day, reflects the tradeoff between a clearing a resource from child LDA against clearing a resource from the parent LDA. The marginal clearing prices of the parent LDA and the child LDA are $106.70 and $120.00 per MW-day.

Figure 5 Optimal solution for scenario 2: Child LDA

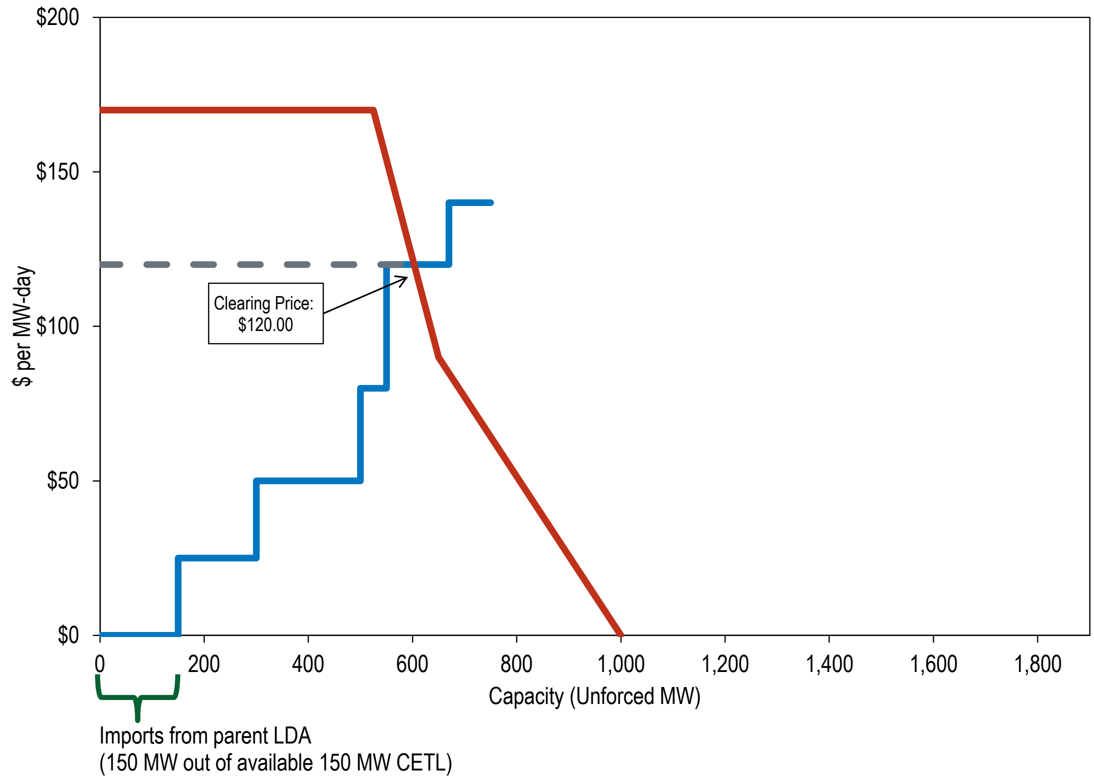


Figure 6 Optimal solution for scenario 2: Parent LDA