Analysis of the 2022/2023 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 sixteenth Reliability Pricing Model (RPM) Base Residual Auction (BRA) for the 2022/2023 Delivery Year which was held from May 19 to 25, 2021, and responds to questions raised by PJM members and market observers about that auction. The MMU prepares a report for each RPM Base Residual Auction.

The BRA for the 2022/2023 Delivery Year had been scheduled for May 2019, but was delayed as a result of Commission review of modifications to the 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.[1] The Commission issued revised MOPR rules on December 19, 2019.[2] 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.[3] [4] The Commission's resultant modified MOPR rules were applied in the 2022/2023 BRA.[5]

On July 30, 2021, PJM filed tariff changes to effectively eliminate the MOPR while creating a confusing and inefficient administrative process that effectively makes it both unnecessary and impossible to prove buyer side market power as PJM defined it.[6] [7] [8] On

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1 163 FERC ¶ 61,236 (2018) at 5 and 6.

2 169 FERC ¶ 61,239 (2019).

3 Id. at 37 and 67.

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

5 169 FERC ¶ 61,239 (2019), *order denying reh'g*, 171 FERC ¶ 61,035 (2020).

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

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

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

September 29, 2021, PJM's proposed changes took effect by operation of law.[9] This new MOPR approach will apply to the 2023/2024 BRA.

This report addresses, explains and quantifies the basic market outcomes in the 2022/2023 BRA. This report also addresses and quantifies the impact on market outcomes of: the shape of the VRR curve; the forecast peak load; changes in Capacity Emergency Transfer Limits (CETL); creation of the Dominion FRR; overstatement of intermittent capacity values; Demand Resources (DR); Energy Efficiency resources (EE); the EE addback; seasonal products; seasonal matching; capacity imports; Price Responsive Demand (PRD); understatement of MOPR offers; offers for nuclear resources; and noncompetitive offers by some generation resources.[10] This report also addresses additional issues including: market power; MOPR; capital recovery factors (CRF); the capacity must offer requirement; the definition of avoidable costs; Capacity Transfer Rights (CTRs) and the market clearing model used by PJM.

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 may have different supply demand balances than the aggregate market. While the market may be long at times, that is not the equilibrium state. Capacity in excess of demand is not sold and, if it does not earn or does not expect to earn adequate revenues in future capacity markets, or in other markets, or does not have value as a hedge, may be expected to retire, provided the market sets appropriate price signals to reflect the availability of excess supply. The demand for capacity includes expected peak load plus a reserve margin, and points on the demand curve, called the Variable Resource Requirement (VRR) curve, exceed peak load plus the reserve margin. The shape of the VRR curve results in the purchase of excess capacity and higher payments by customers. The impact of the VRR curve shape used in the 2022/2023 BRA compared to a vertical demand curve was significant. The defined reliability goal is to have total supply greater than or equal to the defined demand for capacity. The level of purchased demand under RPM has generally exceeded expected peak load plus the target reserve margin, resulting in reserve margins that exceed the target. Demand for capacity is almost entirely inelastic because the market rules require loads to purchase their share of

9 *Notice of Filing Taking Effect by Operation of Law*, Federal Energy Regulatory Commission, ER21-2582-000 (September 29, 2021).

10 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.

the system capacity requirement. The small level of elasticity incorporated in the RPM demand curve is not adequate to modify this conclusion. The result is that any supplier that owns more capacity than the typically small difference between total supply and the defined demand is individually pivotal and therefore has structural market power. Any supplier that, jointly with two other suppliers, owns more capacity than the difference between supply and demand either in aggregate or for a local market is jointly pivotal and therefore has structural market power.

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

The market design for capacity leads, 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 2022/2023 BRA were significantly flawed, as illustrated by the results of the 2021/2022 BRA and the 2022/2023 BRA.[11] 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 2022/2023 BRA resulted in noncompetitive offers and a noncompetitive outcome. The market power rules were corrected by the Commission in an order issued on September 2, 2021, (September 2nd Order) but the modified market power rules were

[11] 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).

not implemented in the 2022/2023 BRA.[12] The result was that capacity market prices were above the competitive level. In addition, the inclusion of offers that were not consistent with the defined terms of the Minimum Offer Price Rule (MOPR) based on the MMU's review, but were accepted by PJM, had a significant impact on the auction results.

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

The definition of the market seller offer cap was changed with the introduction of the Capacity Performance (CP) rules. But the CP market seller offer cap was based on strong assumptions that are not correct. The CP market seller offer cap was significantly overstated as a result. For units that could profitably provide energy under the Capacity Performance design even without a capacity payment because their expected CP bonus payments exceed their net ACR, based on expected unit specific performance, expected balancing ratio, expected performance assessment intervals (PAI) and expected penalty payments, the competitive, profit maximizing offer was defined to be Net CONE times B, where B is the expected average balancing ratio. This was the default offer cap for such units only under strong, defined assumptions.[13] Those assumptions included: there are expected PAI; the number of PAI used in the calculation of the nonperformance charge rate is the same as the expected PAI (360); penalties are imposed by PJM for all cases of noncompliance as defined in the tariff and there are no excuses; the bonus payments equal the penalties; and capacity resources have the ability to costlessly switch between energy only status and capacity resource status.

But those assumptions were not even close to being correct for the 2022/2023 BRA and Net CONE times B was not the correct offer cap as a result. The Capacity Performance paradigm has not worked as anticipated in PJM and is not expected to work in part because the assumptions are never likely to be correct. In addition, PAI is an endogenous variable. The expected number of PAI is a function of the level of capacity resources which is a function of offers and the resultant clearing price. The correct

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12 176 FERC ¶ 61,137 (September 2nd Order).

13 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).

definition of a competitive offer is net ACR, where ACR includes an explicit accounting for the costs of mitigating risk, including the risk associated with capacity market nonperformance penalties. In response to a complaint filed the MMU, the Commission replaced the Net CONE times B market seller offer cap with an ACR offer cap in the September 2nd Order.[14] [15]

The MMU, as part of the process for all BRAs, verifies the reasonableness of cost data and calculates the derived offer caps based on submitted data for resources that submitted unit specific data; calculates unit net revenues; verifies that CP offer caps for low ACR units do not exceed Net CONE times B; evaluate CP offer caps for high ACR units including any risk adders; review Minimum Offer Price Rule (MOPR) unit specific and resource specific exception requests, including for EE; review offers for Planned Generation Capacity Resources; verify capacity exports; verify offers based on opportunity costs; review requests for exceptions to the RPM must offer requirement; review requests for exceptions to the CP must offer requirement; verify the sell offer Equivalent Demand Forced Outage Rates (EFORds); review requests for alternate maximum EFORds; review documentation for Intermittent Resources and Capacity Storage Resources to support CP eligibility; verify clearing prices based on the supply and demand (VRR) curves; and verify that the market power tests were applied correctly.[16] All participants to which the three pivotal supplier (TPS) test was applied (in the RTO, MAAC, EMAAC, ComEd, BGE, and DEOK 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.[17] [18] The

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

15 176 FERC ¶ 61,137.

16 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.

17 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.

18 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

offer caps are intended to reflect the marginal cost of capacity but the offer cap did not reflect the marginal cost of capacity in the 2021/2022 or 2022/2023 BRAs. As a result, no offers were affected by market seller offer caps in the 2022/2023 BRA.

Based on the data and this review, the MMU concludes that the results of the 2022/2023 RPM Base Residual Auction were not competitive as a result of economic withholding by resources that used offers that were consistent with the Net CONE times B offer cap but not consistent with competitive offers based on the correctly calculated offer cap. A competitive offer in the capacity market is equal to net ACR.[19] The ACR values were based on data provided by the participants and were consistent with competitive offers for the relevant capacity and were consistent with PJM's posted default ACR values for the referenced technology.

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

The MMU also concludes that, although a much smaller issue in the 2022/2023 auction, the rules permitted the exercise of market power without mitigation for seasonal resources through uplift payments for noncompetitive offers, rather than through higher prices.[20] Although the impact was small in the 2022/2023 auction, the issue should be addressed immediately in order to prevent the impact from increasing and because the solution is simple.

The recent changes to the capacity market design have addressed some but not all of the significant recommendations made by the MMU in prior reports. The MMU had recommended the elimination of the 2.5 percent demand adjustment (Short-Term Resource Procurement Target). The MMU had recommended that the performance incentives in the capacity market design be strengthened. The MMU had recommended

of a Generation Capacity Resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).

[19] 174 FERC ¶ 61,212 ("March 18th Order") at 65.

[20] 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.

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

The MMU 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.

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.[21] In addition, such sales suppress prices in incremental auctions and provide inefficient incentives for demand resource offer behavior.[22]

The MMU recommends the enforcement of a consistent definition of capacity resource. The MMU recommends that the tariff requirement to be a physical resource be enforced

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21 "PJM Manual 18: PJM Capacity Market," § 3.1 Overview of Demand in the Reliability Pricing Model, Rev. 51 (Oct. 20, 2021).

22 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).

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.[23] [24] 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. 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 greater than the CIR values assigned to such resources. Derating factors and ELCC values are used in capacity auctions to convert the nameplate capacity of intermittent and storage resources into MW of capacity equivalent to resources that can produce for any of the 8,760 hours in a year. Both the capacity derating factors applied to intermittent nameplate capacity in the 2022/2023 BRA and the ELCC calculations to be used for future capacity auctions are based on the assumption that the intermittent resources provide reliable output in excess of their CIRs. But that output is not deliverable when needed for reliability because it is in excess of the defined deliverability rights (CIRs) and therefore should not be included in the definition of intermittent capacity.

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.

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

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

The MMU recommends that the must offer rule in the capacity market apply to all capacity resources. There is no reason to exempt intermittent and storage resources, including hydro. The 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 prevent the exercise of market power via withholding. The failure to apply the must offer requirement will create increasingly significant market power issues in the capacity market as the level of capacity from intermittent and storage resources increases.

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. The tariff distinction between mothball and retirement avoidable costs is unsupported and should be eliminated. Avoidable costs are the costs that a generation owner incurs as a result of operating a generating unit for one year, in particular the delivery year.[25] 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.[26]

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. 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

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[25] OATT Attachment DD § 6.8 (b).

[26] *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).

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 on the supply side, the MMU recommends that the implementation of the EE addback mechanism be modified to ensure that market clearing prices are not affected.[27] If EE is not included on the supply side, there is no reason to have an addback mechanism.

The MMU recommends using the lower of the cost or price-based energy market offer to calculate energy costs in the calculation of the historical net revenues which are an offset to gross ACR in the calculation of unit specific capacity resource offer caps based on net ACR. This recommendation was rejected by FERC.[28] The FERC approved approach, used in the 2021/2022 and 2022/2023 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.[29] 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 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

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

28 See 155 FERC ¶ 61,281 (2016).

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

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 the rule requiring that relatively small proposed increases in the capability of a Generation Capacity Resource be treated as planned for purposes of mitigation and exempted from offer capping be removed.

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.[30] This was a significant issue in the review of MOPR offer floors in the 2022/2023 BRA.

The MMU recommends that the RPM market power mitigation rules be modified to apply offer caps in all cases when the three pivotal supplier test is failed and the sell offer is greater than the offer cap in order to ensure that market power does not result in an increase in uplift payments for seasonal resources. 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.[31] 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.

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30 *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).

31 OATT Attachment DD § 6.5.

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

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 has 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). 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. This conclusion applies to both nonfirm and firm imports from external balancing authorities into PJM. PJM has improved its CETL modeling assumptions related to assumed capacity imports from NYISO.

The MMU recommends that all capacity imports be required to be deliverable to PJM load in an identified LDA prior to the relevant delivery year to ensure that they are full substitutes for internal, physical capacity resources. Pseudo ties alone are not adequate to ensure deliverability to PJM load.

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 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 17 and Table 18, the 139,666.7 MW of cleared and uplift generation and DR for the entire RTO, resulted in a reserve margin of 21.1 percent and a net excess of 7,660.2 MW over the reliability requirement adjusted for FRR and PRD of 132,006.5 MW.[32] [33] Net excess decreased 530.1 MW from the net excess of 8,190.3 MW in the 2021/2022 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 $50.00 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 2022/2023 RPM Base Residual Auction were $3,916,990,303. If PJM had used a vertical demand curve set equal to the reliability requirement for the 2022/2023 BRA and everything else had

32 The 21.1 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. This is how PJM calculates the reserve margin.

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

remained the same, total RPM market revenues for the 2022/2023 BRA would have been $2,659,527,128, a decrease of $1,257,463,175, or 32.1 percent, compared to the actual results. From another perspective, clearing the auction using a downward sloping VRR curve resulted in a 47.3 percent increase in RPM revenues for the 2022/2023 RPM BRA compared to what RPM revenues would have been with a vertical demand curve set equal to the reliability requirement. (Scenario 1)

The accuracy of the peak load forecast had a significant impact on the auction results. An analysis of the RPM auctions for the 2017/2018 through 2021/2022 Delivery Years shows that the peak load forecast for the Third Incremental Auction has been on average 4.3 percent lower than the peak load forecast for the corresponding Base Residual Auction. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2022/2023 RPM Base Residual Auction were $3,916,990,303. If the peak load forecast for the 2022/2023 RPM Base Residual Auction had been 4.3 percent lower and everything else had remained the same, total RPM market revenues for the 2022/2023 RPM Base Residual Auction would have been $3,038,859,236, a decrease of $878,131,066, or 22.4 percent, compared to the actual results. From another perspective, using PJM's peak load forecast for the 2022/2023 Base Residual Auction resulted in a 28.9 percent increase in RPM revenues for the 2022/2023 RPM Base Residual Auction compared to what revenues would have been using a load forecast that is 4.3 percent below the PJM peak load forecast. (Scenario 2)

The increase in the ComEd CETL of 1,265.0 MW, or 22.7 percent, from the 2021/2022 level to the 2022/2023 level had a significant impact on the auction results. The results of the scenario show that the ComEd price for the 2022/2023 RPM Base Residual Auction was lower than it would have been if the CETL had remained at the lower 2021/2022 CETL value. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2022/2023 RPM Base Residual Auction were $3,916,990,303. If the 2021/2022 CETL value for ComEd had been used in the 2022/2023 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2022/2023 RPM Base Residual Auction would have been $4,045,468,797, an increase of $128,478,494, or 3.3 percent, compared to the actual results. From another perspective, the use of the 2022/2023 CETL value for ComEd resulted in a 3.2 percent decrease in RPM revenues for the 2022/2023 RPM Base Residual Auction compared to what RPM revenues would have been using the 2021/2022 CETL value for ComEd. (Scenario 3)

The Dominion LSE in Virginia elected the Fixed Resource Requirement (FRR) option for the 2022/2023 Delivery Year. Dominion's selection of the FRR option had a significant impact on the auction results. If Dominion LSE had not elected the FRR option, the Reliability Requirement of the RTO would have been higher by 18,233.8 MW and Dominion resources would have been offered in the PJM Capacity Market. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2022/2023 RPM Base Residual Auction were $3,916,990,303. If Dominion had participated in the 2022/2023 RPM Base Residual Auction as Dominion participated in the 2021/2022 BRA and everything else had remained the same, total RPM market revenues for the 2022/2023 RPM Base Residual Auction would have been $4,389,932,863. Excluding FRR resources, total RPM market revenues for the rest of the PJM Capacity Market for the 2022/2023 RPM Base Residual Auction would have been $4,009,821,399, an increase of $92,831,097, or 2.4 percent, compared to the actual results. From another perspective, Dominion's choice of the FRR option resulted in a 2.3 percent decrease in RPM revenues for the rest of the PJM Capacity Market for the 2022/2023 RPM Base Residual Auction compared to what those RPM revenues would have been if Dominion had not chosen the FRR option. (Scenario 4)

There is no exact calculation at present of the extent to which intermittent resources offered capacity MW in excess of their CIR values. This sensitivity is intended to provide information about the potential impact of implementing the MMU recommendation. The actual likely impact can be scaled up or down depending on further information about the difference between capacity values, whether determined by derating factors or ELCC levels, and CIR levels. The sensitivity does not include batteries as none were offered in the BRA.[34]

Overstatement of the reliability contribution of intermittent resources can have a significant impact on capacity market results. As a sensitivity to calculate that impact, the capacity MW of intermittent solar and wind capacity resources were reduced by 50 percent. Reducing the reliability contribution of the intermittent solar and wind capacity resources by 50 percent would have had a significant impact on the 2022/2023 RPM Base Residual 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 $3,916,990,303. If the unforced capacity of solar and wind resources offered in the 2022/2023 RPM Base Residual Auction had been reduced by 50 percent and everything else had remained the same, total RPM market revenues for the 2022/2023 RPM Base Residual Auction would have been $4,209,145,809, an increase of $292,155,506, or 7.5 percent, compared to the actual results. From another perspective, the inclusion of all offers from solar and wind resources resulted in a 6.9 percent decrease in RPM revenues for the 2022/2023 RPM Base Residual Auction compared to what RPM revenues would

34 There were no offers for battery resources in the 2022/2023 RPM Base Residual Auction. The 10 hour rule, for determining the capacity value of batteries, was effective for the 2022/2023 RPM Base Residual Auction. Beginning with the 2023/2024 Delivery Year, capacity value for batteries will be determined by PJM's ELCC analysis.

have been if offers from solar and wind resources had been reduced by 50 percent. (Scenario 5)

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 $3,916,990,303. If there had been no offers for DR in the 2022/2023 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2022/2023 RPM Base Residual Auction would have been $4,667,530,509, an increase of $750,540,206, or 19.2 percent, compared to the actual results. From another perspective, the inclusion of DR resulted in a 16.1 percent reduction in RPM revenues for the 2022/2023 RPM Base Residual Auction compared to what RPM revenues would have been without any DR. (Scenario 6)

The inclusion of sell offers for EE, with the EE addback mechanism, had a significant impact on the auction results. The 2022/2023 RPM Base Residual Auction was the fourth 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.[35] The combination of EE and the EE addback mechanism had a significant impact on the auction results. The impact of EE and the addback mechanism was primarily a result of customers paying for a significant level of EE MW and a smaller impact from the price increase resulting from the flawed EE addback. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2022/2023 RPM Base Residual Auction were $3,916,990,303. If 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 2022/2023 RPM Base Residual Auction would have been $3,723,175,053, a decrease of $193,815,249, or 4.9 percent, compared to the actual results. From another perspective, the inclusion of EE offers and the EE addback MW, resulted in a 5.2 percent increase in RPM revenues for the 2022/2023 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 7)

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

Under the flawed EE addback MW rules as implemented, the demand curve was shifted by an amount greater than the quantity of cleared EE, and the clearing price was increased as a result of the implementation of the EE addback mechanism.[36] The purpose of the EE addback mechanism was to eliminate the impact of including EE on the clearing price. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2022/2023 RPM Base Residual Auction were $3,916,990,303. If adjustments to the EE addback MW had been made such that for each LDA the EE cleared MW were equal to the EE addback MW, and everything else had remained the same, total RPM market revenues for the 2022/2023 RPM Base Residual Auction would have been $3,860,997,114, a decrease of $55,993,189, or 1.4 percent, compared to the actual results. From another perspective, the inconsistency between the EE cleared MW and the adjustment to the demand with the EE addback MW resulted in a 1.5 percent increase in RPM revenues for the 2022/2023 RPM Base Residual Auction compared to what RPM revenues would have been if the EE addback MW were equal to the EE cleared MW for each LDA. (Scenario 8)

The 2022/2023 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. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2022/2023 RPM Base Residual Auction were $3,916,990,303. If there had been no submissions from PRD providers in the 2022/2023 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2022/2023 RPM Base Residual Auction would have been $3,971,098,221, an increase of $54,107,919, or 1.4 percent, compared to the actual results. From another perspective, the inclusion of PRD resulted in a 1.4 percent reduction in RPM revenues for the 2022/2023 RPM Base Residual Auction compared to what RPM revenues would have been without any PRD. (Scenario 9)

The 2022/2023 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 2022/2023 RPM Base Residual Auction were $3,916,990,303. If there had been no offers for Seasonal products in the 2022/2023 RPM Base Residual Auction and everything else had remained the same, total RPM

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

market revenues for the 2022/2023 RPM Base Residual Auction would have been $4,088,669,913, an increase of $171,679,610, or 4.4 percent, compared to the actual results. From another perspective, the inclusion of Seasonal offers resulted in a 4.2 percent decrease in RPM revenues for the 2022/2023 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 2022/2023 RPM Base Residual Auction were $3,916,990,303. If seasonal offers were not matched with complementary seasonal offers from other LDAs in the 2022/2023 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues would have been $4,007,550,697, an increase of $90,560,395 or 2.3 percent, compared to the actual results. From another perspective, allowing the matching of offers from seasonal resources across child LDAs in the same parent LDA resulted in a 2.3 percent decrease in RPM revenues for the 2022/2023 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 2022/2023 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 2022/2023 RPM Base Residual Auction were $3,916,990,303. If offers for external generation had been eliminated and everything else had remained the same, total RPM market revenues for the 2022/2023 RPM Base Residual Auction would have been $4,227,125,093, an increase of $310,134,790, or 7.9 percent, compared to the actual results. From another perspective, the impact of including all offers from external generation resources resulted in a 7.3 percent reduction in RPM revenues for the 2022/2023 RPM Base Residual Auction compared to what RPM revenues would have been if no offers from external generation resources 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 resources, 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 2022/2023 RPM Base Residual Auction were $3,916,990,303. If there had been no overstatement of intermittent MW offers and no offers from demand resources, EE, PRD, seasonal resources, or imports in the 2022/2023 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2022/2023 RPM Base Residual Auction would have been $6,657,417,211, an increase of $2,740,426,908, or 70.0 percent, compared to the actual results. From another perspective, the inclusion of overstated intermittent MW offers, and offers from demand resources, EE, PRD, seasonal resources and imports resulted in a 41.2 percent decrease in RPM revenues for the 2022/2023 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 resources and imports. (Scenario 13)

The inclusion of offers that were not consistent with the defined terms of the Minimum Offer Price Rule (MOPR) based on the MMU's review, but were accepted by PJM, had a significant impact on the auction results. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2022/2023 RPM Base Residual Auction were $3,916,990,303. If PJM had subjected all offers to the defined terms of MOPR for 2022/2023 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2022/2023 RPM Base Residual Auction would have been $4,078,113,024, an increase of $161,122,722, or 4.1 percent, compared to the actual results. From another perspective, clearing the auction without subjecting all offers to the defined terms of MOPR resulted in a 4.0 percent decrease in RPM revenues for the 2022/2023 RPM Base Residual Auction compared to what RPM revenues would have been had all offers been subjected to the defined terms of MOPR. (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 Table 22 and Table 23).[37] 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 2022/2023 RPM Base Residual Auction were $3,916,990,303. If all nuclear offers were replaced by $0 per MW-day nuclear offers in the 2022/2023 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2022/2023 RPM Base Residual Auction would have been $3,480,464,207, a decrease of $436,526,096, or 11.1 percent, compared to the actual results. From another perspective, the nuclear offers at levels exceeding $0 per MW-day resulted in a 12.5 percent increase in RPM revenues for the 2022/2023 RPM Base Residual Auction compared to what RPM revenues would have been had all nuclear offers been at $0 per MW-day. (Scenario 15)

[37] 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>.

The MMU identified noncompetitive offers that had a significant impact on the auction results. Some participants' offers were above the competitive level. The MMU recognizes that these market participants followed the capacity market rules by offering at less than the stated offer cap of Net CONE times B. But Net CONE times B is not a competitive offer when the expected number of performance assessment intervals is zero or a very small number and the nonperformance charge rate is defined as Net CONE/30, and the other strong CP assumptions are also not correct. Under these circumstances, a competitive offer is net ACR. That is the way in which most market participants offered in this and prior capacity performance auctions. The Commission recognized the issue and corrected the PJM tariff defined market seller offer cap to net ACR in the September 2nd Order, but the 2022/2023 BRA was conducted with the previous default MSOC of Net CONE times B.

Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2022/2023 RPM Base Residual Auction were $3,916,990,303. If the identified noncompetitive offers had been capped at net ACR in the 2022/2023 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2022/2023 RPM Base Residual Auction would have been $3,694,010,658, a decrease of $222,979,644, or 5.7 percent, compared to the actual results. From another perspective, the noncompetitive offers resulted in a 6.0 percent increase in RPM revenues for the 2022/2023 RPM Base Residual Auction compared to what RPM revenues would have been had the noncompetitive offers been capped at net ACR. (Scenario 16)

Summary Results Tables

Table 1 Scenario summary of RPM revenue: 2022/2023 RPM Base Residual Auction

			Scenario Impact	
Scenario	Scenario Description	RPM Revenue ($ per Delivery Year)	RPM Revenue ($ per Delivery Year)	Percent
0	Actual Results	$3,916,990,303	NA	NA
1	Impact of Downward Sloping VRR Curve	$2,659,527,128	$1,257,463,175	47.3%
2	Impact of Forecast Peak Load	$3,038,859,236	$878,131,066	28.9%
3	Impact of ComEd CETL	$4,045,468,797	($128,478,494)	(3.2%)
4	Impact of Dominion FRR	$4,009,821,399	($92,831,097)	(2.3%)
5	Impact of Intermittent Capacity	$4,209,145,809	($292,155,506)	(6.9%)
6	Inclusion of Demand Resources	$4,667,530,509	($750,540,206)	(16.1%)
7	Inclusion of EE Offers and EE Addback	$3,723,175,053	$193,815,249	5.2%
8	Impact of Incorrect EE Addback	$3,860,997,114	$55,993,189	1.5%
9	Inclusion of PRD	$3,971,098,221	($54,107,919)	(1.4%)
10	Inclusion of Seasonal Products	$4,088,669,913	($171,679,610)	(4.2%)
11	Inclusion of Seasonal Matching Across LDAs	$4,007,550,697	($90,560,395)	(2.3%)
12	Inclusion of Offers from External Generation	$4,227,125,093	($310,134,790)	(7.3%)
13	Impact of DR, EE, PRD, Seasonal Resources, Capacity Imports, and Intermittent Capacity Overstatement	$6,657,417,211	($2,740,426,908)	(41.2%)
14	Impact of Low MOPR Offers	$4,078,113,024	($161,122,722)	(4.0%)
15	Inclusion of Nuclear Offers	$3,480,464,207	$436,526,096	12.5%
16	Impact of Noncompetitive Offers	$3,694,010,658	$222,979,644	6.0%

Table 2 Scenario summary of cleared UCAP: 2022/2023 RPM Base Residual Auction

			Scenario Impact	
Scenario	Scenario Description	Cleared UCAP (MW)	Cleared UCAP (MW)	Percent
0	Actual Results	144,477.3	NA	NA
1	Impact of Downward Sloping VRR Curve	132,006.7	12,470.6	9.4%
2	Impact of Forecast Peak Load	138,811.6	5,665.7	4.1%
3	Impact of ComEd CETL	144,581.9	(104.6)	(0.1%)
4	Impact of Dominion FRR	143,140.5	1,336.8	0.9%
5	Impact of Intermittent Capacity	144,184.3	293.0	0.2%
6	Inclusion of Demand Resources	138,083.6	6,393.7	4.6%
7	Inclusion of EE Offers and EE Addback	139,272.3	5,205.0	3.7%
8	Impact of Incorrect EE Addback	144,068.6	408.7	0.3%
9	Inclusion of PRD	144,727.2	(249.9)	(0.2%)
10	Inclusion of Seasonal Products	144,052.8	424.5	0.3%
11	Inclusion of Seasonal Matching Across LDAs	144,363.9	113.4	0.1%
12	Inclusion of Offers from External Generation	143,951.3	526.0	0.4%
13	Impact of DR, EE, PRD, Seasonal Resources, Capacity Imports, and Intermittent Capacity Overstatement	136,610.7	7,866.6	5.8%
14	Impact of Low MOPR Offers	144,310.2	167.1	0.1%
15	Inclusion of Nuclear Offers	144,581.9	(104.6)	(0.1%)
16	Impact of Noncompetitive Offers	144,477.3	0.0	0.0%

Market Design

Capacity Market Design Changes

Variable Resource Requirement Parameters

Effective for the 2022/2023 and subsequent delivery years, the VRR curve and inputs were revised as part of the quadrennial review, including the elimination of the one percent rightward shift in the VRR curve, updating of the gross CONE and reference CT technology, revision of the weighting of the composite index used for escalating gross CONE for subsequent delivery years, application of a 1.022 factor to gross CONE for subsequent delivery years to account for the annual decline in bonus depreciation scheduled under federal corporate tax law, and inclusion of a 10 percent cost adder in the net energy revenue offset.[38]

CRF

The capacity recovery factors (CRF) in the PJM OATT for the 2022/2023 RPM Base Residual Auction were significantly overstated because they had not been updated to reflect the impacts of the Tax Cuts and Job Act (TCJA) of 2017.[39] [40] [41] The TCJA reduced

38 167 FERC ¶ 61,029 (2019).

39 Tax Cuts and Jobs Act, Pub. L. No. 115-97, 131 Stat. 2096, Stat. 2105 (2017).

the corporate tax rate to 21 percent and introduced bonus depreciation for capital investments placed in service after September 27, 2017.[42] [43] The CRF are used in the calculation of the Avoidable Project Investment Recovery Rate (APIR), included in a capacity resource's Avoidable Cost Rate.[44] Updated CRF values that reflect the TCJA were approved by FERC with an effective date of July 2, 2021.[45] [46]

MOPR

By order issued December 19, 2019, the RPM Minimum Offer Price Rule (MOPR) was modified.[47] The rules applying to natural gas fired capacity resources without state subsidies were retained. The changes included expanding the MOPR to new or existing state subsidized capacity resources; establishing a competitive exemption for new and existing resources other than natural gas fired resources while also allowing a resource specific exception process for those that do not qualify for the competitive exemption; defining limited categorical exemptions for renewable resources participating in renewable portfolio standards (RPS) programs, self supply, DR, EE, and capacity storage; defining the region subject to MOPR for capacity resources with state subsidy as the entire RTO; and defining the default offer price floor for capacity resources with state subsidies as 100 percent of the applicable Net CONE or net ACR values.

The Commission convened a Technical Conference on March 23, 2021, in order to consider whether MOPR should be retained and to consider possible alternative

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40 *Comments of the Independent Market Monitor for PJM*, Monitoring Analytics, LLC, ER21-1844 (May 25, 2021).

41 *Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM*, Monitoring Analytics, LLC, ER21-1844 (July 1, 2021)

42 26 U.S. Code §11(b).

43 See 26 U.S. Code §168(k)(6)(A).

44 OATT Attachment DD § 6.8(a).

45 176 FERC ¶ 61,003 (2021).

46 Designated Letter Order, Federal Energy Regulatory Commission, ER21-1844-001 (October 20, 2021).

47 169 FERC ¶ 61,239 (2019), *order denying reh'g*, 171 FERC ¶ 61,035 (2020).

approaches.[48] The MMU testified at the Technical Conference and provided comments and responses to the Commission's questions following the conference.[49]

On September 29, 2021, PJM's FPA section 205 filing in Docket No. ER21-2582-000 revising the Minimum Offer Price Rule (MOPR) was made effective by operation of law.[50] 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.[51]

The Commission approved PJM's proposed revisions to the PJM market rules to implement a forward looking EAS offset to include forward looking energy and ancillary services revenues rather than historical.[52] The change in the offset affected MOPR floor prices and the results of unit specific reviews under MOPR in the 2022/2023 BRA.

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

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

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

51 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).

52 173 FERC ¶ 61,134 (2020).

Market Design Issues

There are significant market design issues in the capacity market that result in material differences between the prices that result and prices 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 precede the Base Residual Auction for such delivery year.

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). AFAE is defined to include 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.

For the 2022/2023 RPM Base Residual Auction, PJM used the average balancing ratio (77.57 percent) during the PAI that occurred on May 29, 2018, in the Edison area in AEP, and the PAI that occurred on October 2, 2019, in the AEP and BGE Zones. There were six PAI that occurred on May 29, 2018, and 24 PAI that occurred on October 2, 2019.

The competitive offer of a Capacity Performance resource is based on a market seller's expectations of a number of variables, some of which are resource specific: the resource's net going forward costs (net ACR) including gross ACR, forward looking net revenues and the impact of the resource's performance during performance assessment intervals (A) in the delivery year on its risk and the cost to mitigate that risk.[53]

The competitive offer of a Capacity Performance resource is also based on a market seller's expectations of market variables during the delivery year, the impact of these variables on the resource's risk, and the cost to mitigate that risk. These market variables are: the number of performance assessment intervals (PAI) in a delivery year (H) where the resource is located; the level of performance required to meet its capacity obligation during those performance assessment intervals, measured as the average Balancing Ratio (B); and the level of the bonus performance payment rate (CPBR) compared to the

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

nonperformance charge rate (PPR). The total capacity revenues earned by a resource are the sum of revenues earned in the forward capacity auctions and additional bonus revenues earned (or penalties paid) during the delivery year which are a function of unit performance during PAI (A). The level of the bonus performance payment rate depends on the level of underperforming MW net of the underperforming MW excused by PJM during performance assessment intervals for reasons defined in the PJM OATT.[54]

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

The basic assumptions of the Capacity Performance design are not correct and as a result the competitive offer is not Net CONE times B. Two of the core assumptions are that it is reasonable to expect 360 PAI and that it is reasonable to expect that the bonus performance payment rate (bonus rate or CPBR) is equal to the nonperformance charge rate (penalty rate or PPR). There have been effectively zero true PAI since the introduction of the capacity performance model. This does not mean that there will never be PAI or that there will never be 360 PAI. It does mean that it is not reasonable to include the assumption of 360 PAI in establishing the definition of a competitive offer in the capacity market. It does mean that there is no accurate way to calculate expected PAI for the market and that a design based on that calculation will not be based on market fundamentals. The bonus rate has been significantly lower than the penalty rate and there is no reason to expect that to change. As a result, it is not reasonable to include the assumption that CPBR equals PPR in defining a competitive offer in the capacity market. PJM's interpretation of the rules has led to the ability of nonperforming or underperforming resources to avoid penalty payments and to a corresponding reduction in bonus payments. It is not consistent with actual capacity market rules to include the assumption that a generation unit is forgoing energy only status when it decides on a capacity market offer. The PJM Capacity Market has a must offer requirement for a reason; it is required in order to prevent the exercise of market power, particularly given the must buy obligation of load. If a capacity market seller wants to

[54] OATT Attachment DD § 10A (d).

convert to energy only status, the owner must give up its CIRs. Such CIRs could be expensive and difficult to reacquire if the capacity market seller decided to reenter the capacity market.

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

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 actual clearing prices based on actual offers were generally about half of the offer caps. But some generation owners did successfully exercise market power within this design.

Table 3 shows the clearing prices for Capacity Performance Resources in the 2022/2023 BRA by zone compared to the corresponding 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 clearing prices for CP Resources were less than Net CONE times B for every zone. Of the 22 identified zones, the clearing price was less than 50 percent of Net CONE times B in 14 zones and less than 60 percent in 20 zones.[55] The clearing price in BGE Zone was 68.4 of Net CONE times B and the clearing price in Penelec Zone, where Net CONE was lower than other zones, was 78.4 of Net CONE times B. Overall, the average clearing price was 43.6 percent of the average Net CONE times B.

[55] 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 RPM Base Residual Auction

Zone	CP Weighted Average Clearing Price ($ per MW-day)	Net CONE ($ per MW-Day)	Balancing Ratio	Net CONE Times B ($ per MW-day)	CP Clearing Price less Net CONE Times B ($ per MW-day)	CP Clearing Price to Net CONE Times B
AECO	$97.84	$251.59	0.78	$195.16	($97.32)	50.1%
AEP	$50.00	$215.51	0.78	$167.17	($117.17)	29.9%
AP	$50.00	$192.45	0.78	$149.29	($99.29)	33.5%
ATSI	$50.00	$218.79	0.78	$169.71	($119.71)	29.5%
BGE	$114.02	$214.87	0.78	$166.67	($52.65)	68.4%
ComEd	$69.02	$235.27	0.78	$182.50	($113.48)	37.8%
DAY	$50.00	$214.82	0.78	$166.64	($116.64)	30.0%
DEOK	$71.66	$212.27	0.78	$164.65	($92.99)	43.5%
DLCO	$50.00	$212.95	0.78	$165.18	($115.18)	30.3%
DPL	$97.55	$224.18	0.78	$173.90	($76.35)	56.1%
Dominion	$50.00	$237.39	0.78	$184.14	($134.14)	27.2%
EKPC	$50.00	$216.92	0.78	$168.27	($118.27)	29.7%
External	$50.00	$247.26	0.78	$191.80	($141.80)	26.1%
JCPL	$97.84	$253.03	0.78	$196.28	($98.44)	49.8%
Met-Ed	$95.79	$225.90	0.78	$175.23	($79.44)	54.7%
OVEC	$50.00	$204.86	0.78	$158.91	($108.91)	31.5%
PECO	$97.86	$244.83	0.78	$189.91	($92.05)	51.5%
PENELEC	$95.78	$157.47	0.78	$122.15	($26.37)	78.4%
PPL	$95.78	$237.69	0.78	$184.38	($88.60)	51.9%
PSEG	$97.83	$254.80	0.78	$197.65	($99.82)	49.5%
Pepco	$95.27	$246.34	0.78	$191.09	($95.82)	49.9%
RECO	$97.46	$248.64	0.78	$192.87	($95.41)	50.5%
Average	$76.08	$225.81	0.78	$175.16	($99.08)	43.6%

CP Must Offer Requirement

Effective for the 2018/2019 and subsequent delivery years, all Generation Capacity Resources are subject to the CP must offer requirement, with the exception of Intermittent Resources and Capacity Storage Resources which are categorically exempt from the CP 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.[56]

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 storage resources, including hydro. The same rules should apply to all capacity resources. The purpose of the must offer rule, which has been in place since the

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

beginning of the capacity market in 1999, is to prevent the exercise of market power via withholding. The failure to apply the must offer requirement will create increasingly significant market power issues in the capacity market as the level of capacity from intermittent and storage resources increases. In the 2022/2023 BRA, 14,918.8 MW were considered categorically exempt from the must offer requirement based on intermittent and capacity storage classification. Some of these resources were offered as capacity in the BRA and as part of FRR plans. The result was that 2,521.9 MW of intermittent and storage resources (1.7 percent of total cleared MW) were not offered in the 2022/2023 BRA. The capacity resources that were exempt from the must offer requirement were equal to 69.0 percent of the required reserve margin and 47.3 percent of the actual reserve margin, including excess reserves.

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. Avoidable costs are the costs that a generation owner incurs as a result of operating a generating unit for one year. 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 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.

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.[57] 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

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[57] "PJM Manual 14B: PJM Region Transmission Planning Process," § C.2.1.2 Locational Deliverability Areas, Rev. 50 (July 1, 2021). Manual 14B indicates that all "electrically cohesive load areas" are tested.

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 level of CETL, in combination with the internal LDA capacity resource supply curve, could result in locational price differences.[58]

Under the Tariff, PJM determines, in advance of each BRA, whether specific Locational Deliverability Areas (LDAs) will be modeled in the auction, based on criteria which vary from clear to vague. PJM allows only modeled LDAs to price separate in an auction, regardless of the underlying fundamentals. Effective with the 2012/2013 Delivery Year, an LDA will be modeled as a potentially constrained LDA for a delivery year if the Capacity Emergency Transfer Limit (CETL) is less than 1.15 times the Capacity Emergency Transfer Objective (CETO), such LDA had a locational price adder in one or more of the three immediately preceding BRAs, or such LDA is determined by PJM in a preliminary analysis to be likely to have a locational price adder based on historic offer price levels. The rules also provide that starting with the 2012/2013 Delivery Year, EMAAC, SWMAAC, and MAAC LDAs will be modeled as potentially constrained LDAs regardless of the results of these three tests.[59] 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."[60] A reliability requirement and a Variable Resource Requirement (VRR) curve are established for each modeled LDA.

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58 "PJM Manual 18: PJM Capacity Market," § 2.2 Role of Load Deliverability in the Reliability Pricing Model, Rev. 51 (Oct. 20, 2021).

59 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.

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

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 has 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.

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. Derating factors were used in the 2022/2023 BRA. On July 30, 2021, FERC approved new rules in PJM for determining the capacity value of intermittent generators based on the effective load carrying capability (ELCC) method.[61] 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.

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

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

The definition of intermittent capacity is thus not consistent with the way that capacity is defined. This results in an overstatement of the supply of capacity and reduces the clearing price in the capacity market. The MMU recommends that intermittent resources, including storage, not be permitted to offer capacity MW greater than the CIR values assigned to such resources.

Seasonal Capacity

Effective for the 2018/2019 and subsequent delivery years, the RPM market design incorporated seasonal capacity resources.[62] [63]

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.[64] 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.

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62 158 FERC ¶ 62,220.

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

64 OATT Attachment DD § 5.5A(e)(i).

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 resources have the ability to inject more MW in the winter because the lower peak loads in the winter allow higher injections from certain resources without needing any additional network upgrades. But this system capacity in the winter is already paid for by resources that applied for needed network upgrades to inject in the summer to meet the annual peak loads that are expected to occur in the summer.

PJM's practice of giving away winter CIRs that appear to 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 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. 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.

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 resources that do not clear in the same LDA are then matched with complementary seasonal resources 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 resources are required to deliver in the LDA where they are physically located.

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

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

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.[65] 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

[65] See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2017" <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Report_on_Capacity_Replacement_Activity_4_20171214.pdf> (December 14, 2017).

because it permits the shifting of demand from the BRA to the Incremental Auctions, which is inconsistent with the must offer, must buy rules, and the requirement to be an actual, physical resource, governing the BRA. PJM's sell back of capacity in Incremental Auctions exacerbates the incentive for DR to buy out of its BRA positions in IAs.

There are two categories of demand side products included in the RPM market design for the 2022/2023 BRA:[66] [67]

- **Demand Resources (DR).** Interruptible load resource that is offered in an RPM Auction as capacity and receives the relevant LDA or RTO resource clearing price.

- **Energy Efficiency (EE) Resources.** Load resources that are offered in an RPM Auction as capacity and receive the relevant LDA or RTO resource clearing price. An EE Resource is a project designed to achieve a continuous (during peak periods) reduction in electric energy consumption during peak periods that is not reflected in the peak load forecast for the delivery year for which the EE is proposed, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention.[68] The peak period definition for the EE Resource type is even more limited than Limited DR, including only the period from the hour ending 15:00 and the hour ending 18:00 from June through August, excluding weekends and federal holidays. The EE Resource type was eligible to be offered in RPM Auctions starting with the 2012/2013 Delivery Year and in Incremental Auctions in the 2011/2012 Delivery Year.[69]

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

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[66] 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.

[67] 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.

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

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

- **Annual Capacity Performance Resources**

  - **Annual Demand Resources.** A Demand Resource that is required to be available on any day during the Delivery Year for an unlimited number of interruptions. Annual DR is required to be capable of maintaining each interruption between the hours of 10:00 a.m. and 10:00 p.m. EPT for the months of June through October and the following May and between the hours of 6:00 a.m. and 9:00 p.m. EPT for the months of November through April unless there is a PJM approved maintenance outage during the October through April period.

  - **Annual Energy Efficiency Resources.** A project designed to achieve a continuous (during summer and winter peak periods) reduction in electric energy consumption during peak periods that is not reflected in the peak load forecast for the delivery year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention. The peak period definition for the Annual Efficiency Resource type includes the period between the hour ending 15:00 EPT and the hour ending 18:00 EPT from June through August, and between the hour ending 8:00 EPT and the hour ending 9:00 EPT and between the hour ending 19:00 EPT and the hour ending 20:00 EPT from January 1 through February 28, excluding weekends and federal holidays.

- **Seasonal Capacity Performance Resources**

  - **Summer-Period Demand Resources.** A Demand Resource that is required to be available on any day from June through October and the following May of the delivery year for an unlimited number of interruptions. Summer Period DR is required to be capable of maintaining each interruption between the hours of 10:00 a.m. to 10:00 p.m. EPT.

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

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.[70] [71] 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.[72] 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.[73] 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.[74] The EE addback adjustment was intended to ensure that the continued inclusion of EE did not affect prices, but it has not worked 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

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70 *2010 State of the Market Report for PJM*, *Volume 2,* Monitoring Analytics, LLC at 378 (March 10, 2011).

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

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

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

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

PJM's own logic, 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 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."[75]

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. 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 on the supply side, the MMU recommends that the implementation of the EE addback mechanism be modified to ensure that market clearing prices are not affected.[76] If EE is not included on the supply side, 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. This increase is the EE addback amount. For the 2022/2023 BRA, this meant that the RTO VRR curve was shifted to the right by 5,205.0 MW. 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

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75 Schedule 6, Section L.1, Reliability Assurance Agreement Among Load Serving Entities in the PJM Region, PJM Interconnection, L. L. C.

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

the threshold ratio, and 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. For the 2022/2023 BRA, the ratio in the initial solution of 5,205.0/4,810.6=1.081985 did not exceed the applicable threshold ratio of 1.081985. 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 issue has been addressed.[77]

External Generation Resources

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.[78]

Effective May 9, 2017, significantly improved pseudo tie requirements for external generation capacity resources were implemented.[79] 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

77 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 sum of squares of the difference between EE addback MW and quantity of cleared EE across all LDAs increases relative to the previous iteration. "PJM Manual 18: PJM Capacity Market," § 2.4.5 Adjustments to RPM Auction Parameters for EE Resources, Rev. 51 (Oct. 20, 2021).

78 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).

79 161 FERC ¶ 61,197 (2017).

the capacity market seller to provide written acknowledgement from the external Balancing Authority Areas that such pseudo tie does not require tagging and that firm allocations associated with any coordinated flowgates applicable to the external Generation Capacity Resource under any agreed congestion management process then in effect between PJM and such Balancing Authority Area will be allocated to PJM, the requirement for the capacity market seller to obtain long-term firm point to point transmission service for transmission outside PJM with rollover rights and to obtain network external designated transmission service for transmission within PJM, establishing an operationally deliverable standard, and modifying the nonperformance penalty definition for external generation capacity resources to assess performance at subregional transmission organization granularity.

Generation external to the PJM region is eligible to be offered into an RPM auction if it meets specific requirements.[80] [81] [82] Firm transmission service must be acquired from all external transmission providers between the unit and border of PJM and generation deliverability into PJM must be demonstrated prior to the start of the delivery year. In order to demonstrate generation deliverability into PJM, external generators must obtain firm point to point transmission service on the PJM OASIS from the PJM border into the PJM transmission system or by obtaining network external designated transmission service. In the event that transmission upgrades are required to establish deliverability, those upgrades must be completed by the start of the delivery year. The following are also required: the external generating unit must be in the resource portfolio of a PJM member; twelve months of NERC/GADs unit performance data must be provided to establish an EFORd; the net capability of each unit must be verified through winter and summer testing; and a letter of non-recallability must be provided to assure PJM that the energy and capacity from the unit is not recallable to any other balancing authority.

All external generation resources that have an RPM commitment or FRR capacity plan commitment or that are designated as replacement capacity must be offered in the PJM day-ahead energy market.[83]

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80 See “Reliability Assurance Agreement Among Load Serving Entities in the PJM Region,” Schedule 9 & 10.

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

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

83 OATT Schedule 1 § 1.10.1A.

Planned External Generation Capacity Resources are eligible to be offered into an RPM Auction if they meet specific requirements.[84] [85] 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.[86] 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.[87]

CTRs

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

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

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

86 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).

87 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).

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.[88] The allocation sometimes creates significant differences between the capacity cleared to meet the reliability requirement and the capacity obligation allocated to the customers in a zone. For example, ComEd Zone, which is identical to ComEd LDA cleared 27,932.1 MW including 5,574.0 MW of Imports in the 2021/2022 RPM BRA. The ComEd Zone's capacity obligation, immediately after the clearing of the Base Residual Auction was 24,983.0 MW. The final ComEd Zone's capacity obligation for 2021/2022 Delivery Year after the Third Incremental Auction was 22,721.2 MW.

As with CTRs, the underlying reasons for not using the market clearing results 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

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

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.[89] This clearing process always produce a solution with a lower consumer surplus by satisfying child LDA's requirement before satisfying parent LDA's requirement. With this iterative solving, the clearing process may also result in implausible outcomes such as lower prices from a reduction in supply. Absent a fully nodal capacity market clearing process, the MMU recommends that PJM use a non-nested model with all LDAs modeled including VRR curves for all LDAs.

PJM's market clearing algorithm does not include uplift payments in the objective function, resulting in a less accurate and less efficient result.[90] 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

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

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

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.[91] 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.[92] [93]

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.

MMU Review

The MMU reviewed inputs to and results of the 2022/2023 RPM Base Residual Auction:[94]

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91 OATT Attachment DD § 5.14(b).

92 OATT Attachment DD § 5.12(a).

93 For more details, see Attachment A.

94 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

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

- Net Revenues. Calculated forward unit-specific net revenue from PJM energy and ancillary service markets for each PJM Generation Capacity Resource for the 2022/2023 Delivery Year;[95]

- Minimum Offer Price Rule (MOPR). Reviewed requests for Unit Specific Exceptions and Resource 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, 2020, or reviewed requests for alternate maximum EFORds;

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

- Clearing Prices. Verified that the auction clearing prices were accurate, based on submitted offers and the Variable Resource Requirement (VRR) curves; [96]

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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 2022/2023 RPM Base Residual Auction.

95 Net revenue values for the 2022/2023 RPM BRA were calculated consistent with the FERC order effective at the time. *See Order on Section 206 Investigation*, 154 FERC ¶ 61,151 (2016).

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

- 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, EMAAC, ComEd, BGE, and DEOK markets failed the TPS test (Table 4).[97] 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.

As a result of the fact that the Net CONE times B offer cap under the capacity performance design exceeds the competitive level, market power mitigation was not applied to any Capacity Performance sell offers of generation capacity resources in the 2022/2023 RPM Base Residual Auction. All offers were less than the tariff defined offer caps, or not applying the tariff defined offer cap did not increase clearing prices.

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

Table 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

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

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

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.[99] If the RSI_x is equal to 0.0, there is only one supplier and that supplier is a monopoly.

Table 4 RSI results: 2022/2023 RPM Base Residual Auction[100]

	$RSI_{1\ 1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
RTO	0.81	0.73	130	130
MAAC	0.69	0.37	25	25
EMAAC	1.25	0.64	7	7
ComEd	0.43	0.36	14	14
BGE	0.00	0.00	1	1
DEOK	0.00	0.00	1	1

Offer Caps and Offer Floors

The defined Generation Capacity Resource owners were required to submit ACR or opportunity cost data or provide notification of intent to use the Net CONE times B offer cap to the MMU by 120 days prior to the 2022/2023 RPM Base Residual Auction.[101] 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.[102]

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[99] 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.

[100] The RSI shown is the lowest RSI in the market.

[101] 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).

[102] OATT Attachment DD § 6.5.

Table 5 shows the zonal Net CONE times B offer caps for the 2021/2022 and 2022/2023 RPM Base Residual Auctions. In all zones, the Net CONE times B offer cap values decreased from the 2021/2022 RPM Base Residual Auction, mainly due to lower gross CONE values.[103]

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.[104] 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.[105]

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

As shown in Table 6, 1,083 generation resources submitted Capacity Performance offers in the 2022/2023 RPM Base Residual Auction. The MMU calculated offer caps for zero

103 Effective for the 2022/2023 and subsequent delivery years, the VRR curve and inputs were revised as part of the quadrennial review. See 167 FERC ¶ 61,029 (2019).

104 OATT Attachment DD § 6.8(b).

105 OATT Attachment DD § 6.8(a).

106 151 FERC ¶ 61,208.

generation resources that submitted capacity offers. Unit-specific ACR-based offer caps were calculated for zero generation resources (0.0 percent). Of the 1,083 generation resources offered as capacity, 872 generation resources had the Net CONE times B offer cap, zero generation resources had opportunity cost-based offer caps, 35 Planned Generation Capacity Resources had uncapped offers, 40 generation resources had uncapped planned uprates plus Net CONE times B offer cap for the existing portion of the units, four generation resources has uncapped planned uprates plus price taker status for the existing portion of the units, while the remaining 132 generation resources were price takers.

The APIR statistics are not included in this report, because no participants submitted unit specific ACR data. The fact that no resources requested unit specific offer caps is further evidence that the Net CONE times B offer cap exceeded competitive offers.

Market power mitigation measures are applied to MOPR Screened Generation Resources such that the sell offer is set equal to the MOPR Floor Offer Price when the submitted sell offer is less than the MOPR Floor Offer Price and an exception was not granted, or the sell offer is set equal to the agreed upon minimum level of sell offer when the sell offer is less than the agreed upon minimum level of sell offer based on a Unit-Specific Exception or Resource-Specific Exception. As shown in Table 7, of the 13,149.2 ICAP MW of MOPR Unit-Specific Exception and Resource-Specific Exception requests, the MMU agreed with requests for 6,794.7 ICAP MW. Of the 12,001.7 MW offered for MOPR Screened Generation Resources, 8,828.6 MW cleared and 3,173.1 MW did not clear.

Issues addressed during the MOPR unit specific review process for the 2022/2023 BRA included appropriate asset life, degradation of resource performance, operating and maintenance expenses, required capital expenditures, tax assumptions, documentation of forward net revenues, and the use of retail savings as a source of net revenue offset to EE gross CONE. The MMU did not agree with PJM’s judgments about parameters and calculations of MOPR floors in a significant number of cases. These differences had an impact on clearing prices.

Tables for Offer Caps and Offer Floors

Table 5 Net CONE times B: 2021/2022 and 2022/2023 RPM Base Residual Auctions

	2021/2022					2022/2023					Change				
Zone	Gross CONE ($ per MW-Day)	Net E&AS Revenue ($ per MW-Day)	Net CONE ($ per MW-Day)	Balancing Ratio	Net CONE Times B ($ per MW-day)	Gross CONE ($ per MW-Day)	Net E&AS Revenue ($ per MW-Day)	Net CONE ($ per MW-Day)	Balancing Ratio	Net CONE Times B ($ per MW-day)	Gross CONE ($ per MW-Day)	Net E&AS Revenue ($ per MW-Day)	Net CONE ($ per MW-Day)	Balancing Ratio	Net CONE Times B ($ per MW-day)
AECO	$364.78	$54.20	$310.57	0.79	$243.80	$295.89	$44.30	$251.59	0.78	$195.16	($68.89)	($9.91)	($58.98)	(0.01)	($48.64)
AEP	$364.43	$66.46	$297.97	0.79	$233.91	$289.04	$73.53	$215.51	0.78	$167.17	($75.39)	$7.07	($82.46)	(0.01)	($66.74)
AP	$364.43	$86.33	$278.10	0.79	$218.31	$289.04	$96.59	$192.45	0.78	$149.29	($75.39)	$10.26	($85.65)	(0.01)	($69.02)
ATSI	$364.43	$75.64	$288.79	0.79	$226.70	$289.04	$70.25	$218.79	0.78	$169.71	($75.39)	($5.38)	($70.00)	(0.01)	($56.99)
BGE	$386.17	$156.23	$229.94	0.79	$180.50	$300.55	$85.68	$214.87	0.78	$166.67	($85.63)	($70.55)	($15.07)	(0.01)	($13.83)
ComEd	$364.43	$40.35	$324.08	0.79	$254.40	$289.04	$53.77	$235.27	0.78	$182.50	($75.39)	$13.42	($88.81)	(0.01)	($71.90)
DAY	$364.43	$70.27	$294.15	0.79	$230.91	$289.04	$74.22	$214.82	0.78	$166.64	($75.39)	$3.95	($79.33)	(0.01)	($64.27)
DEOK	$364.43	$70.05	$294.38	0.79	$231.09	$289.04	$76.77	$212.27	0.78	$164.65	($75.39)	$6.73	($82.11)	(0.01)	($66.44)
DLCO	$364.43	$65.49	$298.94	0.79	$234.67	$289.04	$76.10	$212.95	0.78	$165.18	($75.39)	$10.60	($85.99)	(0.01)	($69.49)
DPL	$364.78	$82.28	$282.50	0.79	$221.76	$295.89	$71.71	$224.18	0.78	$173.90	($68.89)	($10.57)	($58.32)	(0.01)	($47.86)
Dominion	$364.43	$66.16	$298.26	0.79	$234.13	$289.04	$51.65	$237.39	0.78	$184.14	($75.39)	($14.51)	($60.87)	(0.01)	($49.99)
EKPC	$364.43	$55.61	$308.82	0.79	$242.42	$289.04	$72.12	$216.92	0.78	$168.27	($75.39)	$16.51	($91.90)	(0.01)	($74.15)
External	$370.71	$68.08	$302.63	0.79	$237.56	$293.63	$46.37	$247.26	0.78	$191.80	($77.08)	($21.72)	($55.37)	(0.01)	($45.76)
JCPL	$364.78	$87.85	$276.92	0.79	$217.38	$295.89	$42.86	$253.03	0.78	$196.28	($68.89)	($44.99)	($23.89)	(0.01)	($21.10)
Met-Ed	$367.46	$92.64	$274.82	0.79	$215.73	$289.04	$63.14	$225.90	0.78	$175.23	($78.42)	($29.50)	($48.92)	(0.01)	($40.50)
OVEC	NA	NA	NA	NA	NA	$289.04	$84.18	$204.86	0.78	$158.91	NA	NA	NA	NA	NA
PECO	$364.78	$82.65	$282.13	0.79	$221.47	$295.89	$51.06	$244.83	0.78	$189.91	($68.89)	($31.59)	($37.30)	(0.01)	($31.56)
PENELEC	$367.46	$165.64	$201.82	0.79	$158.43	$289.04	$131.57	$157.47	0.78	$122.15	($78.42)	($34.07)	($44.35)	(0.01)	($36.28)
PPL	$367.46	$84.45	$283.01	0.79	$222.16	$289.04	$51.35	$237.69	0.78	$184.38	($78.42)	($33.10)	($45.32)	(0.01)	($37.78)
PSEG	$364.78	$53.64	$311.13	0.79	$244.24	$295.89	$41.09	$254.80	0.78	$197.65	($68.89)	($12.56)	($56.33)	(0.01)	($46.59)
Pepco	$386.17	$117.56	$268.61	0.79	$210.86	$300.55	$54.21	$246.34	0.78	$191.09	($85.63)	($63.35)	($22.27)	(0.01)	($19.77)
RECO	$364.78	$56.32	$308.45	0.79	$242.13	$295.89	$47.25	$248.64	0.78	$192.87	($68.89)	($9.08)	($59.81)	(0.01)	($49.26)

Table 6 ACR statistics: 2022/2023 RPM Base Residual Auction

Offer Cap/Mitigation Type	Number of Generation Resources Offered	Percent of Generation Resources Offered
Default ACR	NA	NA
Unit specific ACR (APIR)	0	0.0%
Unit specific ACR (APIR and CPQR)	0	0.0%
Unit specific ACR (non-APIR)	0	0.0%
Unit specific ACR (non-APIR and CPQR)	0	0.0%
Opportunity cost	0	0.0%
Default ACR and opportunity cost	NA	NA
Net CONE times B	872	80.5%
Uncapped planned uprates and default ACR	NA	NA
Uncapped planned uprates and opportunity cost	0	0.0%
Uncapped planned uprate and Net CONE times B	40	3.7%
Uncapped planned uprates and price taker	4	0.4%
Uncapped planned generation resources	35	3.2%
Existing generation resources as price takers	132	12.2%
Total Generation Capacity Resources offered	1,083	100.0%

Table 7 MOPR statistics: 2022/2023 RPM Base Residual Auction

			ICAP (MW)			UCAP (MW)	
MOPR Type	Calculation Type	Number of Requests	Requested	MMU Agreed	Offered	Offered	Cleared
Capacity Resources with No State Subsidy	Unit Specific Exception	148	8,849.0	4,882.7	1,720.0	1,702.4	490.3
Capacity Resources with State Subsidy - Cleared	Resource Specific Exception	2	2,134.0	1,240.0	2,134.0	2,126.1	2,126.1
Capacity Resources with State Subsidy - New	Resource Specific Exception	109	2,166.2	672.0	1,207.1	1,248.5	1,104.4
Capacity Resources with No State Subsidy	Default	NA	NA	NA	116.7	98.9	0.0
Capacity Resources with State Subsidy - Cleared	Default	NA	NA	NA	6,590.9	6,332.9	4,954.7
Capacity Resources with State Subsidy - New	Default	NA	NA	NA	459.8	493.0	153.1
Total		259	13,149.2	6,794.7	12,228.5	12,001.7	8,828.6

Generation Capacity Resource Changes

As shown in Table 6, Capacity Performance offers were submitted for 1,083 generation resources in the 2022/2023 RPM Base Residual Auction, compared to 1,133 generation resources offered in the 2021/2022 RPM Base Residual Auction, a net decrease of 50 generation resources.[107] This was a result of 158 fewer generation resources offered offset by 108 additional generation resources offered. The delay in the auction meant that additional capacity resources were available to offer in the BRA. Dominion Energy became an FRR entity prior to the 2022/2023 BRA, meaning that most of Dominion's capacity resources were not offered in the 2022/2023 BRA.[108]

The 108 additional generation resources offered consisted of 93 new resources (5,957.4 MW), 11 resources that were unoffered in the 2021/2022 BRA (1,842.0 MW), three resources that were previously entirely FRR committed (232.9 MW), and one additional resource from disaggregation of RPM resources.[109]

The 93 new Generation Capacity Resources consisted of 68 solar resources (1,450.6 MW), 17 wind resources (527.1 MW), and eight CT and CC resources (3,979.7 MW).[110]

The 158 fewer generation resources offered consisted of 69 additional resources fully committed to FRR (13,951.4 MW), 55 deactivated resources (8,664.6 MW), 13 external resources not offered (1,673.8 MW), 13 intermittent resources not offered (154.9 MW), seven proposed generation capacity resources not offered (601.3 MW), and one resource excused from offering for reasons other than retirement. Table 8 shows Generation Capacity Resources for which deactivation requests have been submitted which affected supply between the 2021/2022 BRA and the 2022/2023 BRA.

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[107] The number of offered generation resources reported in the *Analysis of the 2021/2022 RPM Base Residual Auction* has been revised from 1,132 to 1,133 to account for underlying generation resources in commercially aggregated resources.

[108] *See* 176 FERC ¶ 61,021 (2021).

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

[110] Some numbers not reported as a result of PJM confidentiality rules.

Table 8 Generation Capacity Resource deactivations

Resource Name	LDA	ICAP (MW)	Date Deactivation Notice Submitted	Projected or Actual Deactivation Date
EDGECOMB ROCKY 1-2	RTO	115.5	01-Apr-17	22-Apr-19
TMI 1	MAAC	802.8	30-May-17	20-Sep-19
CRANE 1	BGE	190.0	27-Oct-17	01-Jun-18
CRANE 2	BGE	195.0	27-Oct-17	01-Jun-18
BELLEMEADE CC 1	RTO	265.7	16-Jan-18	16-Apr-18
BREMO 3	RTO	71.0	16-Jan-18	16-Apr-18
BREMO 4	RTO	156.0	16-Jan-18	16-Apr-18
BUGGS ISLAND 1	RTO	69.0	16-Jan-18	19-Apr-18
BUGGS ISLAND 2	RTO	69.0	16-Jan-18	19-Apr-18
CHESTERFIELD 3	RTO	97.5	16-Jan-18	13-Dec-18
CHESTERFIELD 4	RTO	162.0	16-Jan-18	13-Dec-18
POSSUM POINT 3	RTO	96.0	16-Jan-18	13-Dec-18
POSSUM POINT 4	RTO	220.0	16-Jan-18	13-Dec-18
HURT	RTO	83.0	01-May-18	24-Jul-18
NEPCO NUG	PPL	51.0	24-Aug-18	24-Oct-18
MANSFIELD 1	ATSI	830.0	07-Nov-18	05-Feb-19
MANSFIELD 2	ATSI	830.0	07-Nov-18	05-Feb-19
CONESVILLE 5	RTO	405.0	14-Nov-18	01-Jun-19
CONESVILLE 6	RTO	405.0	14-Nov-18	01-Jun-19
MONTOUR 11 AUX	PPL	11.0	19-Nov-18	18-Feb-19
RIVERSIDE CT 7	BGE	19.0	14-Dec-18	14-Mar-19
WARREN COUNTY NUG	EMAAC	10.0	20-Dec-18	01-Jun-19
CONESVILLE 4	RTO	780.0	23-Jan-19	01-Jun-20
GOULD STREET	BGE	97.0	25-Feb-19	01-Jun-19
RIVERSIDE CT 8	BGE	20.0	25-Feb-19	01-Dec-19
MCKEE 3	DPL South	102.0	08-Mar-19	01-Jun-21
COGENTRIX HOPE 1-2	RTO	89.0	14-Mar-19	25-Jun-19
POSSUM POINT 5	RTO	783.1	26-Mar-19	30-Dec-20
CAMBRIA COGEN NUG	MAAC	88.0	17-Jun-19	17-Sep-19
MANSFIELD 3	ATSI	830.0	09-Aug-19	07-Nov-19
KIMBERLY CLARK	EMAAC	9.4	28-Aug-19	04-Sep-19
FRACKVILLE FLUID ENERGY	PPL	43.0	30-Aug-19	01-Mar-20
SOUTHEAST CHICAGO CT 10	ComEd	37.0	30-Aug-19	17-Dec-19
SOUTHEAST CHICAGO CT 11	ComEd	37.0	30-Aug-19	17-Dec-19
SOUTHEAST CHICAGO CT 12	ComEd	37.0	30-Aug-19	17-Dec-19
SOUTHEAST CHICAGO CT 5	ComEd	37.0	30-Aug-19	17-Dec-19
SOUTHEAST CHICAGO CT 6	ComEd	37.0	30-Aug-19	17-Dec-19
SOUTHEAST CHICAGO CT 7	ComEd	37.0	30-Aug-19	17-Dec-19
SOUTHEAST CHICAGO CT 8	ComEd	37.0	30-Aug-19	17-Dec-19
SOUTHEAST CHICAGO CT 9	ComEd	37.0	30-Aug-19	17-Dec-19
WVU	RTO	50.0	03-Oct-19	30-Dec-19
EASTLAKE 6	ATSI Cleveland	24.0	20-Nov-19	18-Feb-20
KEYSTONE NUG	PPL	4.8	28-Feb-20	01-Jun-20
BURLINGTON CTY LF	PSEG	6.0	24-Apr-20	01-Jun-20
SALEM COUNTY LF	EMAAC	1.4	24-Apr-20	01-Jun-20
SUSSEX COUNTY LF	EMAAC	2.0	24-Apr-20	01-Jun-20
DICKERSON 1	Pepco	179.0	15-May-20	13-Aug-20
DICKERSON 2	Pepco	179.0	15-May-20	13-Aug-20
DICKERSON 3	Pepco	179.0	15-May-20	13-Aug-20
CHALK POINT 1	Pepco	333.1	10-Aug-20	01-Jun-21
CHALK POINT 2	Pepco	337.2	10-Aug-20	01-Jun-21
BIRCHWOOD	RTO	237.9	06-Oct-20	01-Mar-21
CAT TRACTOR NUG	MAAC	46.2	29-Oct-20	20-Sep-21
COUNTRYSIDE LF	ComEd	6.4	29-Oct-20	27-Jan-21
HARWOOD 1	PPL	12.9	29-Oct-20	31-May-22
HARWOOD 2	PPL	12.3	29-Oct-20	31-May-22
MARCAL PAPER NUG	PSEG North	70.0	08-Dec-20	12-Mar-21
Total		9,972.2		

RTO Market Results

Total Offers

Table 9 shows total RTO offer data for the 2022/2023 RPM Base Residual Auction. All MW values stated in the RTO section include all nested LDAs.[111] [112] As shown in Table 11, total internal RTO unforced capacity (UCAP), excluding generation winter capacity, decreased 3,388.2 MW (1.7 percent) from 204,690.4 MW in the 2021/2022 RPM BRA to 201,302.2 MW.[113]

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 11, the 3,388.2 MW decrease in internal capacity was a result of net generation capacity modifications (cap mods) (-4,942.2 MW), net DR capacity changes (-1,114.4 MW), net EE modifications (2,140.7 MW), the EFORd effect due to higher sell offer EFORds (-1,412.0 MW), the DR and EE effect due to a lower Load Management UCAP conversion factor (-47.0 MW), and the OVEC integration (1,986.7 MW).[114]

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111 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.

112 Maps of the LDAs can be found in the *2021 Quarterly State of the Market Report for PJM: January through September,* Vol. 2, Section 5, Figures 5-5, 5-6, and 5-7.

113 The capacity includes FRR capacity.

114 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 2021/2022 BRA, this conversion factor was 1.0898. For the 2022/2023 BRA, this conversion factor was 1.0868. 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 "Reliability Assurance Agreement among Load Serving Entities in the PJM Region," 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).

As shown in Table 13, total internal RTO unforced winter capacity for November through April increased 840.2 MW from 1,078.3 MW in the 2021/2022 BRA to 1,918.5 MW in the 2022/2023 BRA. The 840.2 MW increase in winter capacity was a result of net generation winter capacity modifications (840.2 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 2022/2023 RPM Base Residual Auction, excluding external units, and also includes owners' modifications to installed capacity (ICAP) ratings which are permitted under the PJM Reliability Assurance Agreement (RAA) and associated manuals.[115] 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.[116] 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, for FRR committed resources and for imports, total RPM capacity was 172,476.0 MW compared to 196,434.6 MW in the 2021/2022 RPM Base Residual Auction.[117] Generation winter capacity increased by 416.6 MW, FRR volumes increased by 17,633.5 MW, and imports decreased by 3,353.6 MW.[118]

115 See "Reliability Assurance Agreement among Load Serving Entities in the PJM Region," Schedule 9.

116 "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."

117 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.

118 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.

Of the 1,558.0 MW of imports, 0.0 MW were committed to an FRR capacity plan and 1,558.0 MW were offered in the auction, of which 1,558.0 MW cleared. Of the cleared imports, 954.9 MW (61.3 percent) were from MISO.

RPM capacity was reduced by exports of 1,502.8 MW, an increase of 207.8 MW from the 2021/2022 RPM Base Residual Auction. Of total exports, 674.0 MW (44.8 percent) were to NYISO, 550.4 MW (36.6 percent) were to MISO, 87.3 MW (5.8 percent) were to Duke Energy Carolinas, and 191.1 MW (12.7 percent) were to Louisville Gas and Electric Company (LG&E)/Kentucky Utilities Company (KU).

In addition, RPM capacity was reduced by 236.1 MW of Planned Generation Capacity Resources which were not subject to the RPM must offer requirement, by 1,571.6 MW of intermittent resources and 610.5 MW of capacity storage resources which were not subject to the CP must offer requirement, and by 651.2 MW which were excused from the RPM must offer requirement. The excused Existing Generation Capacity Resources were the result of plans for retirement, 643.1 MW, and capacity resources with state subsidy that could not participate because a resource specific MOPR floor was not sought and the applicable default MOPR floor exceeded the default offer cap, 8.2 MW.[119] [120] Subtracting 159.1 MW of FRR optional volumes not offered, an increase of 143.0 MW from the 2021/2022 RPM Base Residual Auction, 842.2 MW of DR and EE not offered, and 246.1 MW of unoffered generation winter capacity resulted in 166,656.3 MW that were available to be offered in the RPM Auction, a decrease of 19,328.4 MW from the 2021/2022 RPM Base Residual Auction.[121] [122] After accounting for these factors, 0.0 MW were not offered and unexcused in the RPM Auction.

Offered MW decreased 18,890.6 MW from 185,547.0 MW to 166,656.3 MW, while the overall RTO Reliability Requirement adjusted for FRR obligations, from which the demand curve is developed, decreased 20,904.2 MW from 153,160.8 MW in the

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

[120] OATT Attachment DD § 5.14(h-1)(2).

[121] 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.

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

2021/2022 RPM Base Residual Auction to 132,256.6 MW.[123] 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.[124] The 20,904.2 MW decrease in the RTO Reliability Requirement adjusted for FRR obligations from the 2021/2022 RPM Base Residual Auction was a result of a 3,086.2 MW decrease in the RTO Reliability Requirement not adjusted for FRR and a 17,818.0 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 2,418.4 MW from the 2021/2022 RPM Base Residual Auction to 150,229.0 MW. The 3,086.2 MW decrease in the RTO Reliability Requirement was a result of a 2,635.5 MW decrease in the forecast peak load in UCAP terms holding the FPR constant at the 2021/2022 level and a 450.7 MW decrease attributable to the change in the FPR. The decrease in the FPR from the 2021/2022 RPM Base Residual Auction was a result of a decrease in the IRM offset by a decrease in the Pool Wide Average EFORd.

Table 14 shows the installed and offered generation capacity for the top five owners. The total installed capacity (195,606.0 MW) includes all Generation Capacity Resources that qualified as PJM Capacity Resources for the 2022/2023 RPM Base Residual Auction (193,005.5 ICAP MW), annual equivalent MW quantity for generation winter capacity (951.4 ICAP MW), and external resources offered or committed to an FRR plan (1,649.1 ICAP MW).

Clearing Prices

Table 16 shows the clearing prices for 2021/2022 BRA and 2022/2023 BRA. The clearing price for the RTO decreased by $90.00 or 64.3 percent from $140.00 in the 2021/2022 BRA to $50.00 in the 2022/2023 BRA. The lower clearing prices in 2022/2023 BRA were the combined result of lower offer prices, higher CETL limits, Dominion election of Fixed

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123 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.

124 PJM. "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 4.1.

Resource Requirement option, lower gross CONE values, subsidies to select generation resources, and reduced demand.

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. Offers for DR and EE were 7.0 percent of the offers greater than $35.00 per MW-day compared to 6.6 percent in the 2021/2022 RPM Base Residual Auction. Offers for coal fired units made up 32.1 percent of the offers greater than $35.00 per MW-day compared to 30.8 percent in the 2021/2022 RPM Base Residual Auction. Offers for nuclear units made up 21.5 percent of the offers greater than $35.00 per MW-day compared to 19.9 percent in the 2021/2022 RPM Base Residual Auction.

Demand Side Resources

Table 33 shows offered and cleared capacity from DR and EE in the 2022/2023 RPM Base Residual Auction compared to the 2021/2022 RPM Base Residual Auction. Offers for DR decreased from 11,494.0 MW in the 2021/2022 BRA to 10,411.4 MW in the 2022/2023 BRA, a decrease of 1,082.6 MW or 9.4 percent. Offers for EE increased from 2,803.2 MW in the 2021/2022 BRA to 4,933.2 MW in the 2022/2023 BRA, an increase of 2,130.0 MW or 76.0 percent.

Capacity Imports

Table 40 shows the MW quantity of imports offered and cleared in the 2007/2008 through 2022/2023 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. Of the 1,558.0 MW of imports offered in the 2022/2023 RPM BRA, 1,558.0 MW (100.0 percent) cleared.

CETO/CETL Values

Table 26 shows the CETL and CETO values used in the 2022/2023 study compared to the 2021/2022 values. The CETL values for the ComEd and PSEG North LDAs changed significantly. The ComEd CETL increased due to "the removal of the Dresden nuclear units from the model."[125] The Dresden nuclear units had notified PJM of their intent to retire prior to the auction, but did not retire.

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[125] See PJM "2022/2023 RPM Base Residual Auction Planning Period Parameters" at p. 4 < https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2022-2023/2022-2023-planning-period-parameters-for-base-residual-auction-pdf.ashx> (February 8, 2021).

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 they 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.[126] 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. This conclusion applies to both nonfirm and firm imports from external balancing authorities into PJM. The imports from neighboring regions are not substitutes for PJM's internal capacity resources and should not be treated as substitutes.

The Price Impacts of Constraints in the RPM Market

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

There were five locationally binding constraints in the 2022/2023 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.[127]

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[126] See proposed Revisions to "PJM Manual 14B: PJM Region Transmission Planning Process," presented at July 27, 2017, meeting of the Markets and Reliability Committee.

[127] For more details on the clearing algorithm, see Attachment A.

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.[128] As shown in Table 15, the preliminary Net Load Price is $50.09 per MW-day in the RTO.

As shown in Table 17 and Table 18, the 139,666.7 MW of cleared and uplift generation and DR for the entire RTO, resulted in a reserve margin of 21.1 percent and a net excess of 7,660.2 MW over the reliability requirement adjusted for FRR and PRD of 132,006.5 MW (Installed Reserve Margin (IRM) of 14.5 percent).[129] [130] [131] [132] Net excess decreased 530.1 MW from the net excess of 8,190.3 MW in the 2021/2022 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 $50.00 per MW-day.

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

129 Prior to the 2012/2013 Delivery Year, net excess under RPM was calculated as cleared capacity plus uplift MW 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 plus uplift MW 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 plus uplift MW 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 plus uplift MW less the reliability requirement.

130 The IRM decreased from 15.8 percent in the 2021/2022 RPM Base Residual Auction to 14.5 percent in the 2021/2022 RPM Base Residual Auction.

131 The 21.1 percent reserve margin does not include EE on the supply side or the EE addback on the demand side. This is how PJM calculates the reserve margin.

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

The market results in the 2022/2023 BRA did not include uplift MW and payments resulting from partially cleared resources.

Uplift MW and payments can also occur for resources electing the New Entry Price Adjustment (NEPA) or Multi-Year Pricing Option.[133] [134] If an offer clears in an auction under either option and if a qualifying resource does not clear in the two subsequent BRAs, the process specified in the Tariff is triggered, and the resource is awarded an uplift payment.[135] The market results in the 2022/2023 BRA did not include make whole MW or payments related to NEPA or Multi-Year Pricing Option.

The market results in the 2022/2023 BRA did 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 19 shows offered and cleared MW by LDA, resource type, and season in the 2022/2023 RPM Base Residual Auction. Of the 151,311.8 MW of generation offers, 150,257.3 MW were for the annual season. Of the 10,411.4 MW of DR offers, 10,071.0 MW were for the annual season. Of the 4,933.2 MW of EE offers, 4,807.5 MW were for the annual season.

Table 20 shows the weighted average sell offer prices by LDA, resource type, and season. For generation, the weighted average sell offer prices in RTO for winter were greater than the weighted average sell offer prices for annual, 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.

133 OATT Attachment DD § 5.14(c)(2).

134 OATT Attachment DD § 6.8(a).

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

Table 21 shows the offered MW by resource type, offer/product type, and price range as percent of Net CONE times B in the 2022/2023 RPM Base Residual Auction. Capacity Performance generation offers between 50 percent of Net CONE times B and greater than 100 percent times Net CONE times B decreased by 8,059.4 MW from the 2021/2022 RPM Base Residual Auction. About 99.9 percent of capacity offered at less than Net CONE times B.

Table 22 shows cleared MW by zone and fuel source. Of the 151,311.8 MW offered for generation resources, 131,072.9 MW cleared (86.6 percent). Of the 144,477.3 cleared MW in the entire RTO, 19,794.4 MW (13.7 percent) cleared in AEP, followed by 19,223.7 MW (13.3 percent) in ComEd and 14,118.7 MW (9.8 percent) in PPL. Of the 131,072.9 cleared MW for generation resources in the entire RTO, 71,426.4 MW (54.5 percent) were gas resources, followed by 26,600.1 MW (20.3 percent) from coal resources and 21,050.3 MW (16.1 percent) from nuclear resources. Cleared MW from coal resources decreased 14,593.5 from the 2021/2022 RPM Base Residual Auction while cleared MW from EE increased 1,965.9 MW from the 2021/2022 RPM Base Residual Auction.

The 22,179.0 MW uncleared MW in the entire RTO were the result of offer prices which exceeded the clearing prices. Of the 22,179.0 uncleared MW in the entire RTO, 239.1 MW were EE offers, 1,701.1 MW were DR offers, and the remaining 20,238.9 MW were generation offers.[136] Table 23 presents details on the generation offers that did not clear. Of the 20,238.9 MW of uncleared generation offers, 9,646.4 MW (47.7 percent) were for generation resources greater than 40 years old, and 10,592.5 MW (52.3 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 2022/2023 BRA. Of the 308 generation resources that did not clear 20,238.9 MW in the 2022/2023 BRA, 143 of those generation resources did not clear 6,230.0 MW in RPM Auctions for the 2021/2022 Delivery Year. Of those 143 generation resources that did not clear MW in RPM Auctions for the 2022/2023 and 2021/2022 Delivery Years, 90 of those generation resources did not clear 3,156.8 MW in RPM Auctions for the 2020/2021 Delivery Year. Thus, 6,230.0 MW of capacity did not clear in two sequential auctions, but 3,156.8 MW did not clear in three sequential auctions.

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

CTRs

For LDAs in which the RPM auctions for a delivery ear 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.[137]

At the time of clearing the 2022/2023 RPM Base Residual Auction, EMAAC had 4,946.8 MW of CTRs with a total value of $3,737,529, COMED had 2,367.2 MW of CTRs with a total value of $16,381,936, BGE had 4,745.1 MW of CTRs with a total value of $53,188,332 and DEOK had 3,034.8 MW of CTRs with a total value of $24,026,133. The value of the CTRs will be redefined prior to the delivery year.

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

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

Analysis of Market Results

The MMU analyzed the impacts of specific market design features, definitions of capacity, and market behavior. The market design features are: the slope of the VRR curve; forecast error; ComEd CETL changes; and Dominion FRR. The definitions of capacity are: DR; EE; seasonal products; and imports. The market behaviors are: MOPR floor enforcement; nuclear plant offers; and noncompetitive 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, the impact of changes in CETL and the impact of Dominion's change to FRR status.

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

[137] 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.

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.[138] Figure 1 shows the shape of the VRR curve compared to a vertical demand curve at the reliability requirement for the 2022/2023 RPM Base Residual Auction.

In proposing the downward sloping portion of the VRR curve, PJM asserted that the sloping VRR curve recognizes the value of incremental capacity above the target reserve margin providing additional reliability benefit at a declining rate.[139]

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.[140] 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).

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138 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)]*.

139 See 117 FERC ¶ 61,331 (2006).

140 "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>.

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 2022/2023 RPM Base Residual Auction and everything else had remained the same. All binding constraints would have remained the same. The RTO clearing price would have decreased to $30.00 per MW-day, and the clearing quantity would have decreased to 132,006.7 MW. The clearing quantity of seasonal capacity would have decreased to 660.8 MW. The MAAC clearing price would have decreased to $75.00 per MW-day, and the clearing quantity would have decreased to 59,889.1 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have remained the same at 164.6 MW. The EMAAC clearing price would have decreased to $79.16 per MW-day, and the clearing quantity would have decreased to 26,667.5 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 0 MW. The BGE clearing price would have decreased to $95.89 per MW-day, and the clearing quantity would have decreased to 2,058.1 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have decreased to $55.00 per MW-day, and the clearing quantity would have decreased to 17,092.0 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have decreased to 256.7 MW. The DEOK clearing price would have decreased to $46.48 per MW-day, and the clearing quantity would have decreased to 1,637.1 MW. The clearing quantity of seasonal capacity for satisfying DEOK'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 2022/2023 RPM Base Residual Auction were $3,916,990,303. If PJM had used a vertical demand curve set equal to the reliability requirement for 2022/2023 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2022/2023 RPM Base Residual Auction would have been $2,659,527,128, a decrease of $1,257,463,175, or 32.1 percent, compared to the actual results. From another perspective, clearing the auction using a downward sloping VRR curve resulted in a 47.3 percent increase in RPM revenues for the 2022/2023 RPM Base Residual Auction compared to what RPM revenues would have been with a vertical demand curve set equal to the reliability requirement.

Impact of the Forecast Peak Load (Scenario 2)

The accuracy of the peak load forecast had a significant impact on auction results. Table 28 summarizes the peak load forecasts for the RPM auctions held since May 2010. 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 2017/2018 through 2021/2022 shows that the peak load forecast for the Third Incremental Auction has been on average 4.3 percent lower than the peak load forecast for the corresponding Base Residual Auction.

Table 29 shows the results if the peak load forecast had been 4.3 percent lower in the 2022/2023 RPM Base Residual Auction and everything else had remained the same. All binding constraints except the EMAAC constraint would have remained binding. The RTO clearing price would have decreased to $40.00 per MW-day, and the clearing quantity would have decreased to 138,811.1 MW. The amount of cleared seasonal capacity would have decreased to 655.8 MW. The MAAC clearing price would have decreased to $79.18 per MW-day, and the clearing quantity would have decreased to 62,013.1 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have decreased to 159.6 MW. The EMAAC clearing price would have decreased to $79.18 per MW-day, and the clearing quantity would have decreased to 27,904.1 MW. The clearing quantity for seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 0 MW. The BGE clearing price would have decreased to $87.88 per MW-day, and the clearing quantity would have decreased to 2,235.5 MW. The clearing quantity for seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have decreased to $55.00 per MW-day, and the clearing quantity would have decreased to 18,206.7 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have decreased to 251.7 MW. The DEOK clearing price would have decreased to $52.17 per MW-day and the clearing quantity would have decreased to 1,886.8 MW. The clearing quantity of seasonal capacity cleared for satisfying DEOK'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 2022/2023 RPM Base Residual Auction were $3,916,990,303. If the peak load forecast for the 2022/2023 RPM Base Residual Auction had been 4.3 percent lower and everything else had remained the same, total RPM market revenues for the 2022/2023 RPM Base Residual Auction would have been $3,038,859,236, a decrease of $878,131,066, or 22.4 percent, compared to the actual results. From another perspective, using PJM's peak load forecast for the 2022/2023 Base Residual Auction resulted in a 28.9 percent increase in RPM revenues for the 2022/2023 RPM Base Residual Auction compared to what revenues would have been using a load forecast that is 4.3 percent below the PJM peak load forecast. (Scenario 2)

Impact of ComEd CETL (Scenario 3)

The increase in the ComEd CETL of 1,265.0 MW, or 22.7 percent, from the 2021/2022 level to the 2022/2023 level had a significant impact on the auction results.

Table 30 shows the results if the 2021/2022 CETL value for ComEd had been used in the 2022/2023 RPM Base Residual Auction and everything else had remained the same. The results of the scenario show that the ComEd price for the 2022/2023 RPM Base Residual Auction was lower than it would have been if the CETL had remained at the lower 2021/2022 CETL value. All binding constraints would have remained the same. The RTO clearing price would have decreased to $47.00 per MW-day, and the clearing quantity would have increased to 144,581.8 MW. The clearing quantity of seasonal capacity would have remained the same at 686.8 MW. The MAAC clearing price would have remained the same at $95.79 per MW-day, and the clearing quantity would have decreased to 64,614.1 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have remained the same at 164.6 MW. The EMAAC clearing price would have decreased to $97.70 per MW-day, and the clearing quantity would have increased to 29,335.3 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement remained the same at 0 MW. The BGE clearing price would have remained the same at $126.50 per MW-day, and the clearing quantity would have remained the same at 2,494.5 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement remained the same at 0 MW. The ComEd clearing price would have increased to $93.80 per MW-day, and the clearing quantity would have increased to 20.297.7 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement remained the same at 282.7 MW. The DEOK clearing price would have remained the same at $71.69 per MW-day and the clearing quantity would have remained the same at 2,114.8 MW. The clearing quantity of seasonal capacity for satisfying DEOK's reliability requirement remained the same at 0 MW.

Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2022/2023 RPM Base Residual Auction were $3,916,990,303. If the 2021/2022 CETL value for ComEd had been used in the 2022/2023 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2022/2023 RPM Base Residual Auction would have been $4,045,468,797, an increase of $128,478,494, or 3.3 percent, compared to the actual results. From another perspective, the use of the 2022/2023 CETL value for ComEd resulted in a 3.2 percent decrease in RPM revenues for the 2022/2023 RPM Base Residual Auction compared to what RPM revenues would have been using the 2021/2022 CETL value for ComEd.

Impact of Dominion FRR (Scenario 4)

The Dominion LSE in Virginia elected the Fixed Resource Requirement (FRR) option for the 2022/2023 Delivery Year. Dominion's selection of the FRR option had a significant impact on the auction results. If Dominion LSE had not elected the FRR option, the Reliability Requirement of the RTO would have been higher by 18,233.8 MW and Dominion resources would have been offered in the PJM Capacity Market.

Table 31 shows the results of the 2022/2023 RPM Base Residual Auction had Dominion stayed in the PJM Capacity Market and everything else had remained the same. All binding constraints would have remained binding. The RTO clearing price would have increased to $55.98 per MW-day, and the clearing quantity would have increased to 163,475.2 MW, including 18,449.6 MW of FRR committed resources. For comparison, Dominion committed 18,683.8 MW of unforced capacity for meeting the FRR. The clearing quantity of seasonal capacity would have remained the same at 686.8 MW. The MAAC clearing price would have decreased to $95.14 per MW-day, and the clearing quantity would have increased to 64,625.9 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have decreased to 160.3 MW. The EMAAC clearing price would have decreased to $97.70 per MW-day, and the clearing quantity would have increased to 29,335.3 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 0 MW. The BGE clearing price would have remained the same at $126.50 per MW-day, and the clearing quantity would have remained the same at 2,494.5 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have remained the same at $68.96 per MW-day, and the clearing quantity would have remained the same at 19,197.5 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have remained the same at 282.7 MW. The DEOK clearing price would have remained the same at $71.69 per MW-day, and the clearing quantity would have remained the same at 2,114.8 MW. The clearing quantity of seasonal capacity for satisfying DEOK'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 2022/2023 RPM Base Residual Auction were $3,916,990,303. If Dominion had participated in the 2022/2023 RPM Base Residual Auction as Dominion participated in the 2021/2022 BRA and everything else had remained the same, total RPM market revenues for the 2022/2023 RPM Base Residual Auction would have been $4,389,932,863. Excluding FRR resources, total RPM market revenues for the rest of the PJM Capacity Market for the 2022/2023 RPM Base Residual Auction would have been $4,009,821,399, an increase of $92,831,097, or 2.4 percent, compared to the actual results. From another perspective, Dominion's choice of the FRR option resulted in a 2.3 percent decrease in RPM revenues for the rest of the PJM Capacity Market for the 2022/2023 RPM Base Residual Auction compared to what RPM revenues would have been had Dominion not chosen the FRR option.

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 overstating the amount of intermittent capacity, the impact of demand side resources, the impact of EE, the impact of PRD, the impact of seasonal capacity and the impact of external capacity resources.

Impact of Intermittent Capacity Overstatement (Scenario 5)

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 the effective load carrying capability (ELCC) method.[141] The MMU opposed 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.[142] But, both the capacity derating factors applied to intermittent nameplate capacity in the 2022/2023 BRA and the ELCC calculations to be used for future capacity auctions are based on the assumption that the intermittent resources can provide reliable output in excess of their CIRs. In order to test the impacts of correcting that error, the MMU performed a sensitivity analysis. The purpose of the analysis is solely to demonstrate the impact of correcting any overstatement of the reliability contribution of intermittent resources. The MMU is not asserting that the actual capacity value of intermittents is or is not 50 percent of the level assumed in the derating or ELCC analyses.

There is no exact calculation at present of the extent to which intermittent resources offered capacity MW in excess of their CIR values. This sensitivity is intended to provide information about the potential impact of implementing the MMU recommendation.

[141] See 176 FERC ¶ 61,056.

[142] 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).

The actual likely impact can be scaled up or down depending on further information about the difference between derating and ELCC levels and CIR levels. The sensitivity does not include batteries as none were offered in the BRA.[143]

Overstatement of the reliability contribution of intermittent resources can have a significant impact on capacity market results. As a sensitivity to calculate that impact, the capacity MW of intermittent solar and wind capacity resources were reduced by 50 percent. Reducing the reliability contribution of the intermittent solar and wind capacity resources by 50 percent would have had a significant impact on the 2022/2023 RPM Base Residual Auction results. Table 32 shows the results if the reliability contribution of solar and wind resources were reduced by 50 percent. All binding constraints would have remained binding except the EMAAC import limit would not have been binding. The RTO clearing price would have increased to $58.40 per MW-day, and the clearing quantity would have decreased to 144,184.4 MW. The clearing quantity of seasonal capacity would have decreased to 337.7 MW. The MAAC clearing price would have increased to $99.04 per MW-day, and the clearing quantity would have decreased to 64,555.6 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have decreased to 96.2 MW. The EMAAC clearing price would have increased to $99.04 per MW-day, and the clearing quantity would have increased to 29,446.0 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have increased to 48.0 MW. The BGE clearing price would have remained the same at $126.50 per MW-day, and the clearing quantity would have remained the same at 2,494.5 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0.0 MW. The ComEd clearing price would have increased to $78.35 per MW-day, and the clearing quantity would have decreased to 19,135.2 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have decreased to 131.1 MW. The DEOK clearing price would have increased to $75.00 per MW-day, and the clearing quantity would have decreased to 2,107.6 MW. The clearing quantity of seasonal capacity for satisfying DEOK'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 2022/2023 RPM Base Residual Auction were $3,916,990,303. If the unforced capacity of solar and wind resources offered in the 2022/2023 RPM Base

[143] There were no offers for battery resources in the 2022/2023 RPM Base Residual Auction. The 10 hour rule, for determining the capacity value of batteries, was effective for the 2022/2023 RPM Base Residual Auction. Beginning with the 2023/2024 Delivery Year, capacity value for batteries will be determined by PJM's ELCC analysis.

Residual Auction had been reduced by 50 percent and everything else had remained the same, total RPM market revenues for the 2022/2023 RPM Base Residual Auction would have been $4,209,145,809, an increase of $292,155,506, or 7.5 percent, compared to the actual results. From another perspective, the inclusion of all offers from solar and wind resources resulted in a 6.9 percent decrease in RPM revenues for the 2022/2023 RPM Base Residual Auction compared to what RPM revenues would have been if offers from solar and wind capacity resources had been reduced by 50 percent.

Impact of Demand Resources (Scenario 6)

The inclusion of all sell offers for demand resources, including annual and seasonal, had a significant impact on the auction results. Table 34 shows the results if there were no offers for DR in the 2022/2023 RPM Base Residual Auction and everything else had remained the same. All binding constraints would have remained binding except for the EMAAC, the ComEd and the DEOK import limits which would not have been binding. The RTO clearing price would have increased to $84.08 per MW-day, and the clearing quantity would have decreased to 138,083.7 MW. The clearing quantity of seasonal capacity would have decreased to 261.1 MW. The MAAC clearing price would have increased to $102.03 per MW-day, and the clearing quantity would have decreased to 62,438.9 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have decreased to 57.9 MW. The EMAAC clearing price would have increased to $102.03 per MW-day, and the clearing quantity would have decreased to 28,765.5 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 0 MW. The BGE clearing price would have remained the same at $126.50 per MW-day, and the clearing quantity would have decreased to 2,290.8 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have increased to $84.08 per MW-day, and the clearing quantity would have decreased to 18,334.4 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have decreased to 135.4 MW. The DEOK clearing price would have increased to $84.08 per MW-day, and the clearing quantity would have decreased to 2,018.9 MW. The clearing quantity of seasonal capacity for satisfying DEOK'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 2022/2023 RPM Base Residual Auction were $3,916,990,303. If there had been no offers for DR in the 2022/2023 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2022/2023 RPM Base Residual Auction would have been $4,667,530,509, an increase of $750,540,206, or 19.2 percent, compared to the actual results. From another perspective, the inclusion of DR resulted in a 16.1 percent reduction in RPM revenues for the 2022/2023 RPM Base Residual Auction compared to what RPM revenues would have been without any DR.

Impact of EE (Scenario 7)

The inclusion of sell offers for EE, with the EE addback mechanism, had a significant impact on the auction results. The 2022/2023 RPM Base Residual Auction was the fourth 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.[144] The impact of EE and the addback mechanism was primarily a result of customers paying for a significant level of EE MW and a smaller impact from the price increase resulting from the flawed EE addback.

Table 35 shows the results 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. All binding constraints would have remained the same. The RTO clearing price would have remained the same at $50.00 per MW-day, and the clearing quantity would have decreased to 139,269.8 MW. The clearing quantity of seasonal resources would have decreased to 451.9 MW. The MAAC clearing price would have decreased to $93.57 per MW-day, and the clearing quantity would have decreased to 62,589.4 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have increased to 165.2 MW. The EMAAC clearing price would have decreased to $97.74 per MW-day, and the clearing quantity would have decreased to 28,182.0 MW. The clearing quantity of seasonal resources for satisfying EMAAC's reliability requirement would have remained the same at 0 MW. The BGE clearing price would have remained the same at $126.50 per MW-day, and the clearing quantity would have decreased to 2,290.8 MW. The clearing quantity of seasonal resources for satisfying BGE's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have decreased to $65.00 per MW-day, and the clearing quantity would have decreased to 18,291.0 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have decreased to 147.3 MW. The DEOK clearing price would have remained the same at $71.69 per MW-day, and the clearing quantity would have decreased to 1,964.5 MW. The clearing quantity of seasonal capacity for satisfying DEOK's reliability requirement would have remained the same at 0 MW.

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

Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2022/2023 RPM Base Residual Auction were $3,916,990,303. If 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 2022/2023 RPM Base Residual Auction would have been $3,723,175,053, a decrease of $193,815,249, or 4.9 percent, compared to the actual results. From another perspective, the inclusion of EE offers and the EE addback MW resulted in a 5.2 percent increase in RPM revenues for the 2022/2023 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 5.2 percent increase in total RPM market revenues reflects a 3.7 percent increase in the amount of capacity purchased and a 1.4 percent increase in the weighted average capacity price. EE accounted for 4,694.1 MW of the increase in cleared capacity and non EE accounted for 513.5 MW of the increase in cleared capacity.

Impact of Incorrect EE Addback MW (Scenario 8)

Under the flawed EE addback MW rules as implemented, the demand curve was shifted by an amount greater than the quantity of cleared EE, and the clearing price was increased as a result of the implementation of the EE addback mechanism.[145] The purpose of the EE addback mechanism was to eliminate the impact of including EE on the clearing price.

PJM adjusts the VRR curve by adding the EE addback MW to the reliability requirement for each LDA. The EE addback MW is determined by PJM after a review of the EE measurement and verification plans.[146] If the ratio of the EE addback MW to cleared EE MW in the BRA exceeds a predetermined threshold, then PJM adjusts the EE addback MW and reruns the auction clearing a second and final time. Based on an Issue Charge introduced by the MMU, PJM updated the EE addback rules to address this issue, effective with the 2023/2024 Base Residual Auction. Starting with the 2023/2024 Base Residual Auction, the EE addback MW will be iteratively adjusted to effectively eliminate the excess EE addback.[147] For the 2022/2023 RPM Base Residual Auction, PJM

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

146 "PJM Manual 18: PJM Capacity Market," § 2.4.5 Adjustments to RPM Auction Parameters for EE Resources, Rev. 51 (Oct. 20, 2021).

147 Id. at 33.

cleared 4,810.6 MW of EE and the EE addback was 5,205 MW for the aggregate RTO LDA. The resulting ratio, 1.081985, did not exceed the threshold ratio of 1.817718016. Even though the threshold was not exceeded, the EE addback MW exceeded the EE cleared MW by 394.4 MW. The increased demand as a result of the excessive EE addback had a significant impact on 2022/2023 RPM BRA results.

Table 36 shows the results if adjustments to the EE addback MW had been made such that for each LDA the EE cleared MW were equal to the EE addback MW in the 2022/2023 RPM Base Residual Auction, and everything else had remained the same. All binding constraints would have remained the same. The RTO clearing price would have remained the same at $50.00 per MW-day, and the clearing quantity would have decreased to 144,068.3 MW. The clearing quantity of Seasonal capacity would have remained the same at 686.8 MW. The MAAC clearing price would have decreased to $94.38 per MW-day, and the clearing quantity would have decreased to 64,483.9 MW. The clearing quantity of Seasonal capacity for satisfying MAAC's reliability requirement would have remained the same at 164.6 MW. The EMAAC clearing price would have decreased to $97.78 per MW-day, and the clearing quantity would have decreased to 29,238.2 MW. The clearing quantity of Seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 0 MW. The BGE clearing price would have remained the same at $126.50 per MW-day, and the clearing quantity would have decreased to 2,490.0 MW. The clearing quantity of Seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have decreased to $65.00 per MW-day, and the clearing quantity would have decreased to 19,014.9 MW. The clearing quantity of Seasonal capacity for satisfying ComEd's reliability requirement would have remained the same at 282.7 MW. The DEOK clearing price would have remained the same at $71.69 per MW-day, and the clearing quantity would have decreased to 2,104.6 MW. The clearing quantity of seasonal capacity for satisfying DEOK'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 2022/2023 RPM Base Residual Auction were $3,916,990,303. If adjustments to the EE addback MW had been made such that for each LDA the EE cleared MW were equal to the EE addback MW and everything else had remained the same, total RPM market revenues for the 2022/2023 RPM Base Residual Auction would have been $3,860,997,114, a decrease of $55,993,189, or 1.4 percent, compared to the actual results. From another perspective, the inconsistency between the EE cleared MW and the adjustment to the demand with the EE addback MW resulted in a 1.5 percent increase in RPM revenues for the 2022/2023 RPM Base Residual Auction compared to what RPM revenues would have been if the EE addback MW were equal to the EE cleared MW for each LDA.

The total revenue for this scenario is 3.7 percent higher than the total revenue for Scenario 7 where the EE offers and EE addback were removed. The 3.7 percent increase reflects a 3.4 percent increase in cleared capacity and a 0.2 percent increase in the weighted average capacity price. EE accounted for 4,679.8 MW of the increase in cleared capacity and non EE accounted for 118.7 MW of the increase in cleared capacity.

Impact of Price Responsive Demand (Scenario 9)

The 2022/2023 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 2022/2023 RPM Base Residual Auction and everything else had remained the same. All binding constraints would have remained the same except the EMAAC import limit would not have been binding. The RTO clearing price would have remained the same at $50.00 per MW-day, and the clearing quantity would have increased to 144,727.2 MW. The clearing quantity of seasonal capacity would have remained the same at 686.8 MW. The MAAC clearing price would have increased to $98.76 per MW-day, and the clearing quantity would have increased to 64,810.4 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have remained the same at 164.6 MW. The EMAAC clearing price would have increased to $98.76 per MW-day, and the clearing quantity would have increased to 29,372.4 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 0 MW. The BGE clearing price would have remained the same at $126.50 per MW-day, and the clearing quantity would have increased to 2,581.4 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have remained the same at $68.96 per MW-day, and the clearing quantity would have increased to 19,197.5 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have remained the same at 282.7 MW. The DEOK clearing price would have remained the same at $71.69 per MW-day, and the clearing quantity would have remained the same at 2,114.8 MW. The clearing quantity of seasonal capacity for satisfying DEOK'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 2022/2023 RPM Base Residual Auction were $3,916,990,303. If there had been no submissions from PRD providers in the 2022/2023 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2022/2023 RPM Base Residual Auction would have been $3,971,098,221, an increase of $54,107,919, or 1.4 percent, compared to the actual results. From another perspective, the inclusion of PRD resulted in a 1.4 percent reduction in RPM revenues for the 2022/2023 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 Capacity (Scenario 10)

The 2022/2023 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 2022/2023 RPM Base Residual Auction and everything else had remained the same. All binding constraints would have remained binding except the EMAAC import limit would not have been binding. The RTO clearing price would have increased to $54.79 per MW-day, and the clearing quantity would have decreased to 144,052.6 MW. The clearing quantity of seasonal capacity would have decreased to 0 MW. The MAAC clearing price would have increased to $97.72 per MW-day, and the clearing quantity would have decreased to 64,502.6 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 decreased to $97.72 per MW-day, and the clearing quantity would have increased to 29,347.8 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 0 MW. The BGE clearing price would have remained the same at $126.50 per MW-day, and the clearing quantity would have decreased to 2,493.8 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have increased to $77.56 per MW-day, and the clearing quantity would have decreased to 19,002.0 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have decreased to 0 MW. The DEOK clearing price would have remained the same at $71.69 per MW-day, and the clearing quantity would have decreased to 2,108.9 MW. The clearing quantity of seasonal capacity for satisfying DEOK'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 2022/2023 RPM Base Residual Auction were $3,916,990,303. If there had been no offers for Seasonal products in the 2022/2023 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2022/2023 RPM Base Residual Auction would have been $4,088,669,913, an increase of $171,679,610, or 4.4 percent, compared to the actual results. From another perspective, the inclusion of Seasonal offers resulted in a 4.2 percent decrease in RPM revenues for the 2022/2023 RPM Base Residual Auction compared to what RPM revenues would have been without any seasonal resources.

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 2022/2023 RPM Base Residual Auction and everything else had remained the same. All binding constraints would have remained binding except that the EMAAC import limit would not have been binding. The RTO clearing price would have increased to $53.25 per MW-day, and the clearing quantity would have decreased to 144,363.2 MW. The clearing quantity of seasonal capacity would have decreased to 432.9 MW. The MAAC clearing price would have increased to $97.75 per MW-day, and the clearing quantity would have decreased to 64,578.4 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have decreased to 116.0 MW. The EMAAC clearing price would have decreased to $97.75 per MW-day, and the clearing quantity would have increased to 29,401.7 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have increased to 96.0 MW. The BGE clearing price would have remained the same at $126.50 per MW-day, and the clearing quantity would have remained the same at 2,494.5 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0.0 MW. The ComEd clearing price would have remained the same at $68.96 per MW-day, and the clearing quantity would have remained the same at 19,197.5 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have remained the same at 282.7 MW. The DEOK clearing price would have remained the same at $71.69 per MW-day, and the clearing quantity would have remained the same at 2,114.8 MW. The clearing quantity of seasonal capacity for satisfying DEOK'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 2022/2023 RPM Base Residual Auction were $3,916,990,303. If seasonal offers were not matched with complementary seasonal offers from the other LDAs in the 2022/2023 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues would have been $4,007,550,697, an increase of $90,560,395, or 2.3 percent, compared to the actual results. From another perspective, allowing the matching of offers from seasonal resources across child LDAs in the same parent LDA resulted in a 2.3 percent decrease in RPM revenues for the 2022/2023 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 External Generation (Scenario 12)

The inclusion of capacity imports in the 2022/2023 RPM Base Residual Auction had a significant impact on the auction results.

Table 41 shows the results if import offers for external generation resources in the 2022/2023 RPM Base Residual Auction had been eliminated and everything else had remained the same. All binding constraints would have remained the same. The RTO clearing price would have increased to $65.08 per MW-day, and the clearing quantity would have decreased to 143,947.0 MW. The clearing quantity of seasonal capacity would have increased to 701.2 MW. The MAAC clearing price would have remained the same at $95.79 per MW-day, and the clearing quantity would have decreased to 64,609.7 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have decreased to 159.6 MW. The EMAAC clearing price would have increased to $97.90 per MW-day, and the clearing quantity would have decreased to 29,331.8 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 0 MW. The BGE clearing price would have remained the same at $126.50 per MW-day, and the clearing quantity would have remained the same at 2,494.5 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have remained the same at $68.96 per MW-day, and the clearing quantity would have remained the same at 19,197.5 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have remained the same at 282.7 MW. The DEOK clearing price would have remained the same at $71.69 per MW-day, and the clearing quantity would have remained the same at 2,114.8 MW. The clearing quantity of seasonal capacity for satisfying DEOK'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 2022/2023 RPM Base Residual Auction were $3,916,990,303. If offers for external generation had been eliminated and everything else had remained the same, total RPM market revenues for the 2022/2023 RPM Base Residual Auction would have been $4,227,125,093, an increase of $310,134,790, or 7.9 percent, compared to the actual results. From another perspective, the impact of including all offers from external generation resources resulted in a 7.3 percent reduction in RPM revenues for the 2022/2023 RPM Base Residual Auction compared to what RPM revenues would have been if no offers from external generation resources were included in the auction.

Impact of DR, EE, PRD, Seasonal Resources, Capacity Imports and Intermittent Capacity Overstatement (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 resources, 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 resources, imports, and no intermittent capacity overstatement in the 2022/2023 RPM Base Residual Auction and everything else had remained the same. All binding constraints would have remained binding except MAAC, EMAAC, ComEd and DEOK import limits would not have been binding. The RTO clearing price would have increased to $133.47 per MW-day, and the clearing quantity would have decreased to 136,611.0 MW. The clearing quantity of seasonal capacity would have decreased to 0 MW. The MAAC clearing price would have increased to $133.47 per MW-day, and the clearing quantity would have decreased to 62,426.3 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 $133.47 per MW-day, and the clearing quantity would have decreased to 28,934.5 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 0 MW. The BGE clearing price would have increased to $133.47 per MW-day, and the clearing quantity would have decreased to 2,357.5 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have increased to $133.47 per MW-day, and the clearing quantity would have increased to 20,232.4 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have decreased to 0 MW. The DEOK clearing price would have increased to $133.47 per MW-day, and the clearing quantity would have increased to 2,565.8 MW. The clearing quantity of seasonal capacity for satisfying DEOK'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 2022/2023 RPM Base Residual Auction were $3,916,990,303. If there had been no overstatement of intermittent MW offers and no offers from DR, EE, PRD, seasonal resources, or imports in the 2022/2023 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2022/2023 RPM Base Residual Auction would have been $6,657,417,211, an increase of $2,740,426,908, or 70.0 percent, compared to the actual results. From another perspective, the inclusion of overstated intermittent MW offers, and offers from DR, EE, PRD, seasonal resources and imports resulted in a 41.2 percent reduction in RPM revenues for the 2022/2023 RPM Base Residual Auction compared to what RPM revenues would have been without overstated intermittent MW offers, and offers from DR, EE, PRD, seasonal resources and imports.

Impact of Market Behavior Issues

The MMU analyzed the impact of specific, significant market behavior issues, including the impact of offers not required to meet the MOPR rules, the impact of offers from nuclear plants and the impact of noncompetitive offers.

Impact of Low MOPR Offers (Scenario 14)

The inclusion of offers that were not consistent with the defined terms of the Minimum Offer Price Rule (MOPR) based on the MMU's review, but were accepted by PJM, had a significant impact on the auction results.

Resources subject to MOPR could use default MOPR offers or unit specific MOPR offers. The MMU reviewed all requests for unit specific MOPR offers. The MMU issued a determination letter to market sellers stating agreement or disagreement and the reasons for any disagreements and the MMU's MOPR calculation. For generation resources, the MMU disagreed with excess and unsupported resources' asset life, unsupported investment tax credit (ITC) calculations, failure to account for degradation of solar panels, and inclusion of REC revenue in the net revenue offset. For energy efficiency resources, the MMU disagreed with the calculation of the savings offset, primarily based on the inclusion of asserted retail savings in the wholesale offer. The MMU also provided its determinations and a detailed explanation for each calculation to PJM. PJM approved significantly lower MOPR floor values than those determined by the MMU. (See Table 7.)

Table 43 shows the results of the 2022/2023 RPM Base Residual Auction if the MMU MOPR determinations had been used instead of PJM approved MOPR floor values and everything else had remained the same. All binding constraints would have remained the same. The RTO clearing price would have increased to $54.79 per MW-day, and the clearing quantity would have decreased to 144,309.7 MW. The clearing quantity of seasonal capacity would have decreased to 627.4 MW. The MAAC clearing price would have increased to $98.72 per MW-day, and the clearing quantity would have decreased to 64,561.1 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have decreased to 163.9 MW. The EMAAC clearing price would have increased to $99.01 per MW-day, and the clearing quantity would have decreased to 29,322.9 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 0 MW. The BGE clearing price would have remained the same at $126.50 per MW-day, and the clearing quantity would have remained the same at 2,494.5 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have increased to $71.02 per MW-day, and the clearing quantity would have decreased to 19,183.8 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have remained the same at 282.7 MW. The DEOK clearing price would have increased to $73.29 per MW-day, and the clearing quantity would have decreased to 2,111.3 MW. The clearing quantity of seasonal capacity for satisfying DEOK'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 2022/2023 RPM Base Residual Auction were $3,916,990,303. If PJM had subjected all offers to the defined terms of MOPR for 2022/2023 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2022/2023 RPM Base Residual Auction would have been $4,078,113,024, an increase of $161,122,722, or 4.1 percent, compared to the actual results. From another perspective, clearing the auction without subjecting all offers to the defined terms of MOPR resulted in a 4.0 percent decrease in RPM revenues for the 2022/2023 RPM Base Residual Auction compared to what RPM revenues would have been had all offers been subjected to the defined terms of MOPR.

Impact of Nuclear Offers (Scenario 15)

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 Table 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.

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 even though more nuclear capacity cleared in the 2022/2023 RPM BRA compared to the 2021/2022 RPM BRA (See Table 22 and Table 23).[148] [149] 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 44 shows the results of the 2022/2023 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 been binding except the EMAAC and ComEd import limits would not have been binding. The RTO clearing price would have decreased to $41.01 per MW-day, and the clearing quantity would have increased to 144,790.8 MW. The clearing quantity of seasonal capacity would have decreased to 557.7 MW. The MAAC clearing price would have decreased to $94.42 per MW-day, and the clearing quantity would have increased to 64,638.9 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have remained the same at 164.6 MW. The EMAAC clearing price would have decreased to $94.42 per MW-day, and the clearing quantity would have increased to 29,388.7 MW. The clearing

148 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>.

149 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>.

quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 0 MW. The BGE clearing price would have remained the same at $126.50 per MW-day, and the clearing quantity would have remained the same at 2,494.5 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have decreased to $41.01 per MW-day, and the clearing quantity would have increased to 21,042.0 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have decreased to 153.6 MW. The DEOK clearing price would have remained the same at $71.69 per MW-day, and the clearing quantity would have remained the same at 2,114.8 MW. The clearing quantity of seasonal capacity for satisfying DEOK'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 2022/2023 RPM Base Residual Auction were $3,916,990,303. If all nuclear offers were replaced by $0 per MW-day nuclear offers in the 2022/2023 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2022/2023 RPM Base Residual Auction would have been $3,480,464,207, a decrease of $436,526,096, or 11.9 percent, compared to the actual results. From another perspective, the nuclear offers at levels exceeding $0 per MW-day resulted in a 12.5 percent increase in RPM revenues for the 2022/2023 RPM Base Residual Auction compared to what RPM revenues would have been had all nuclear offers been at $0 per MW-day.

Impact of Noncompetitive Offers (Scenario 16)

The MMU identified noncompetitive offers that had a significant impact on the auction results. Some participants' offers were above the competitive level. The MMU recognizes that these market participants followed the capacity market rules by offering at less than the stated offer cap of Net CONE times B. But Net CONE times B is not a competitive offer when the expected number of performance assessment intervals is zero or a very small number and the non-performance charge rate is defined as Net CONE/30, and the other strong CP assumptions are also not correct. Under these circumstances, a competitive offer, under the logic defined in PJM's capacity performance filing, is net ACR. That is the way in which most market participants offered in this and prior capacity performance auctions. The Commission recognized the issue and corrected the PJM tariff defined market seller offer cap to net ACR in the September 2nd Order, but the 2022/2023 BRA was conducted with the previous default MSOC of Net CONE times B.

The FERC approved PJM tariff simply defined the offer cap for the 2022/2023 BRA as Net CONE times B, rather than including the full logic supporting the definition of the offer cap under the capacity performance paradigm. If the tariff had defined the offer cap consistent with PJM's filing in the capacity performance matter, the offer cap would have been net ACR rather than Net CONE times B. The Commission addressed this issue for the auctions conducted after the 2022/2023 BRA (September 2nd Order).

The PJM tariff defines the balancing ratio (B) used in the default offer cap as the average of balancing ratios during the actual performance assessment intervals that occurred during the three calendar years preceding the auction.[150] The average balancing ratio during the PAI that occurred in May 2018 and October 2019 was 77.57 percent. PJM did not propose any updates to the nonperformance charge rate or the default offer cap definition of Net CONE times B for the 2022/2023 BRA. PJM continued to assume that there would be 360 PAIs (30 hours) for the 2022/2023 Delivery Year. This assumption is not consistent with the recent history of emergency actions in the PJM energy market. The correct way to account for the lack of performance assessment intervals during the three year history would have been to recognize that this means that unit specific net ACR is the offer cap under the capacity performance design. The Commission addressed this issue, and ordered that the offer caps be defined as unit specific net ACR, consistent with the competitive offer calculation logic that PJM filed in response to a deficiency letter issued by the Commission in the Capacity Performance docket.[151] [152]

Table 45 shows the results for the 2022/2023 RPM Base Residual Auction if the noncompetitive offers identified by the MMU had been capped at net ACR. All binding constraints would have remained the same except that the DEOK import constraint would not have been binding. The RTO clearing price would have remained the same at $50.00 per MW-day, and the clearing quantity would have remained the same at 144,477.3 MW. The clearing quantity of seasonal capacity would have decreased to 605.8 MW. The MAAC clearing price would have decreased to $93.51 per MW-day, and the clearing quantity would have increased to 64,655.4 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have decreased to 159.6 MW. The EMAAC clearing price would have decreased to $94.60 per MW-day, and the clearing quantity would have increased to 29,364.8 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 0 MW. The BGE clearing price would have decreased to $100.00 per MW-day, and the clearing quantity would have increased to 2,539.9 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have

150 OATT Attachment DD § 6.4(a).

151 *See* Response of PJM Interconnection, L.L.C. to Commission's March 31, 2015 Information Request, Docket No. ER15-623 (April 10, 2015).

152 September 2nd Order.

remained the same at 0 MW. The ComEd clearing price would have decreased to $51.64 per MW-day, and the clearing quantity would have increased to 19,312.4 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have decreased to 201.7 MW. The DEOK clearing price would have decreased to $50.00 per MW-day, and the clearing quantity would have increased to 2,222.5 MW. The clearing quantity of seasonal capacity for satisfying DEOK'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 2022/2023 RPM Base Residual Auction were $3,916,990,303. If the identified noncompetitive offers had been capped at net ACR in the 2022/2023 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2022/2023 RPM Base Residual Auction would have been $3,694,010,658, a decrease of $222,979,644, or 5.7 percent, compared to the actual results. From another perspective, the noncompetitive offers resulted in a 6.0 percent increase in RPM revenues for the 2022/2023 RPM Base Residual Auction compared to what RPM revenues would have been had the noncompetitive offers been capped at net ACR.

Tables and Figures for RTO Market

Table 9 RTO offer statistics: 2022/2023 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	193,005.5	184,661.1		
DR capacity	10,622.8	11,539.9		
EE capacity	4,696.9	5,101.3		
Generation winter capacity	951.4	951.4		
Total internal RTO capacity	209,276.6	202,253.7		
FRR	(33,715.2)	(31,335.6)		
Imports	1,649.1	1,558.0		
RPM capacity	177,210.5	172,476.1		
Exports	(1,525.3)	(1,502.8)		
FRR optional	(164.8)	(159.1)		
Excused Existing Generation Capacity Resources	(750.7)	(651.3)		
Unoffered Planned Generation Capacity Resources	(264.8)	(236.1)		
Unoffered Intermittent Resources	(1,681.6)	(1,571.6)		
Unoffered Capacity Storage Resources	(620.7)	(610.5)		
Unoffered generation winter capacity	(246.1)	(246.1)		
Unoffered DR and EE	(775.0)	(842.2)		
Available	171,181.5	166,656.3	100.0%	100.0%
Generation offered	157,054.9	151,311.8	91.7%	90.8%
DR offered	9,584.4	10,411.4	5.6%	6.2%
EE offered	4,542.2	4,933.2	2.7%	3.0%
Total offered	171,181.5	166,656.3	100.0%	100.0%
Unoffered Existing Generation Capacity Resources	0.0	0.0	0.0%	0.0%

Table 10 Capacity modifications (ICAP): 2022/2023 RPM Base Residual Auction[153]

	ICAP (MW)					
	RTO	MAAC	EMAAC	ComEd	BGE	DEOK
Generation increases	8,991.6	1,048.4	352.6	1,666.1	144.6	120.7
Generation decreases	(16,253.4)	(4,041.3)	(491.4)	(508.6)	(882.5)	(6.1)
Capacity modifications net increase/(decrease)	(7,261.8)	(2,992.9)	(138.8)	1,157.5	(737.9)	114.6
DR increases	2,711.1	718.8	351.9	334.4	21.4	90.7
DR decreases	(3,729.6)	(1,280.8)	(497.6)	(484.4)	(202.8)	(88.7)
DR net increase/(decrease)	(1,018.5)	(562.0)	(145.7)	(150.0)	(181.4)	2.0
EE increases	4,494.3	1,795.9	1,005.9	696.6	165.9	137.6
EE decreases	(2,526.3)	(880.9)	(594.0)	(579.8)	(78.2)	(83.2)
EE modifications increase/(decrease)	1,968.0	915.0	411.9	116.8	87.7	54.4
Net capacity/DR/EE modifications increase/(decrease)	(6,312.3)	(2,639.9)	127.4	1,124.3	(831.6)	171.0
OVEC integration generation	2,120.0					
Net internal capacity increase/(decrease)	(4,192.3)	(2,639.9)	127.4	1,124.3	(831.6)	171.0

153 Only cap mods that had a start date on or before June 1, 2022, and DR and EE plans for the 2022/2023 RPM Base Residual Auction are included.

Table 11 Capacity modifications (UCAP): 2022/2023 RPM Base Residual Auction

	UCAP (MW)					
	RTO	MAAC	EMAAC	ComEd	BGE	DEOK
Generation increases	8,856.2	1,025.9	346.9	1,660.1	118.2	120.7
Generation decreases	(13,798.4)	(3,906.3)	(447.0)	(460.2)	(856.0)	(5.9)
Capacity modifications net increase/(decrease)	(4,942.2)	(2,880.4)	(100.1)	1,199.9	(737.8)	114.8
DR increases	2,949.7	780.8	382.0	364.1	23.1	98.8
DR decreases	(4,064.1)	(1,395.8)	(542.4)	(527.9)	(221.0)	(96.7)
DR net increase/(decrease)	(1,114.4)	(615.0)	(160.4)	(163.8)	(197.9)	2.1
EE increases	4,895.1	1,954.9	1,094.7	759.1	180.6	149.9
EE decreases	(2,754.4)	(960.9)	(647.7)	(631.8)	(85.3)	(90.9)
EE modifications increase/(decrease)	2,140.7	994.0	447.0	127.3	95.3	59.0
Net capacity/DR/EE modifications increase/(decrease)	(3,915.9)	(2,501.4)	186.5	1,163.4	(840.4)	175.9
OVEC integration generation	1,986.7					
EFORd effect	(1,412.0)	(205.7)	229.2	(76.7)	6.5	(422.2)
DR and EE effect	(47.0)	(14.6)	(6.7)	(8.2)	(1.1)	(1.3)
Net internal capacity increase/(decrease)	(3,388.2)	(2,721.7)	409.0	1,078.5	(835.0)	(247.6)

Table 12 Winter capacity modifications (ICAP): 2022/2023 RPM Base Residual Auction

	ICAP (MW)					
	RTO	MAAC	EMAAC	ComEd	BGE	DEOK
Generation increases	960.7	98.0	0.0	498.6	0.0	0.0
Generation decreases	(120.5)	(5.6)	0.0	(111.9)	0.0	0.0
Capacity modifications net increase/(decrease)	840.2	92.4	0.0	386.7	0.0	0.0
DR increases	0.0	0.0	0.0	0.0	0.0	0.0
DR decreases	0.0	0.0	0.0	0.0	0.0	0.0
DR net increase/(decrease)	0.0	0.0	0.0	0.0	0.0	0.0
EE increases	0.0	0.0	0.0	0.0	0.0	0.0
EE decreases	0.0	0.0	0.0	0.0	0.0	0.0
EE modifications increase/(decrease)	0.0	0.0	0.0	0.0	0.0	0.0
Net internal capacity increase/(decrease)	840.2	92.4	0.0	386.7	0.0	0.0

Table 13 Winter capacity modifications (UCAP): 2022/2023 RPM Base Residual Auction

	UCAP (MW)					
	RTO	MAAC	EMAAC	ComEd	BGE	DEOK
Generation increases	960.7	98.0	0.0	498.6	0.0	0.0
Generation decreases	(120.5)	(5.6)	0.0	(111.9)	0.0	0.0
Capacity modifications net increase/(decrease)	840.2	92.4	0.0	386.7	0.0	0.0
DR increases	0.0	0.0	0.0	0.0	0.0	0.0
DR decreases	0.0	0.0	0.0	0.0	0.0	0.0
DR net increase/(decrease)	0.0	0.0	0.0	0.0	0.0	0.0
EE increases	0.0	0.0	0.0	0.0	0.0	0.0
EE decreases	0.0	0.0	0.0	0.0	0.0	0.0
EE modifications increase/(decrease)	0.0	0.0	0.0	0.0	0.0	0.0
Net capacity/DR/EE modifications increase/(decrease)	840.2	92.4	0.0	386.7	0.0	0.0
EFORd effect	0.0	0.0	0.0	0.0	0.0	0.0
DR and EE effect	0.0	0.0	0.0	0.0	0.0	0.0
Net internal capacity increase/(decrease)	840.2	92.4	0.0	386.7	0.0	0.0

Table 14 Installed and offered generation capacity by parent company: 2022/2023 RPM Base Residual Auction

Parent Company	ICAP (MW)	Percent of Total ICAP	Offered ICAP (MW)	Percent of Total Offered ICAP
Exelon Corporation	20,831.5	10.6%	20,048.5	12.8%
Dominion Resources, Inc.	20,301.3	10.4%	868.0	0.6%
American Electric Power Company, Inc.	15,125.3	7.7%	1,627.0	1.0%
Vistra Energy Corp.	11,695.4	6.0%	11,690.7	7.4%
LS Power Group	11,414.0	5.8%	11,414.0	7.3%

Table 15 Net load prices: 2022/2023 RPM Base Residual Auction

	$ per MW-day					
	RTO	MAAC	EMAAC	ComEd	BGE	DEOK
Resource clearing price	$50.00	$95.79	$97.86	$68.96	$126.50	$71.69
Preliminary zonal capacity price	$50.00	$95.79	$97.86	$69.04	$126.50	$71.69
Adjusted preliminary zonal capacity price	$50.09	$96.42	$98.04	$69.13	$127.07	$71.78
Base zonal CTR credit rate	$0.00	$0.00	$0.29	$1.96	$19.15	$12.41
Preliminary net load price	$50.09	$96.42	$97.75	$67.17	$107.92	$59.38

Table 16 Clearing Prices: 2021/2022 and 2022/2023 RPM Base Residual Auctions

LDA	2021/2022 BRA	2022/2023 BRA	Change	Percent
RTO	$140.00	$50.00	($90.00)	(64.3%)
MAAC	$140.00	$95.79	($44.21)	(31.6%)
EMAAC	$165.73	$97.86	($67.87)	(41.0%)
SWMAAC	$140.00	$95.79	($44.21)	(31.6%)
PSEG	$204.29	$97.86	($106.43)	(52.1%)
PSEG North	$204.29	$97.86	($106.43)	(52.1%)
DPL South	$165.73	$97.86	($67.87)	(41.0%)
Pepco	$140.00	$95.79	($44.21)	(31.6%)
ATSI	$171.33	$50.00	($121.33)	(70.8%)
ATSI Cleveland	$171.33	$50.00	($121.33)	(70.8%)
ComEd	$195.55	$68.96	($126.59)	(64.7%)
BGE	$200.30	$126.50	($73.80)	(36.8%)
PPL	$140.00	$95.79	($44.21)	(31.6%)
DAY	$140.00	$50.00	($90.00)	(64.3%)
DEOK	$140.00	$71.69	($68.31)	(48.8%)

Table 17 Reserve margin: 2022/2023 RPM Base Residual Auction

	Reserve Margin Calculation	
Forecast peak load ICAP (MW)	150,229.0	A
FRR peak load ICAP (MW)	28,535.5	B
PRD ICAP (MW)	230.0	C
Installed reserve margin (IRM)	14.5%	D
Pool-wide average EFORd	5.08%	E
Forecast pool requirement (FPR)	1.0868	F=(1+D)*(1-E)
Cleared UCAP (generation and DR)	139,666.7	G
Cleared ICAP (generation and DR)	147,141.5	H=G/(1-E)
RPM peak load ICAP (MW)	121,463.5	J=A-B-C
Reserve margin ICAP (MW)	25,678.0	K=H-J
Reserve margin (%)	21.1%	L=K/J
Reserve cleared in excess of IRM ICAP (MW)	8,065.8	M=K-D*J
Reserve cleared in excess of IRM (%)	6.6%	N=M/J
RPM peak load UCAP (MW)	115,293.2	P=J*(1-E)
RPM reliability requirement UCAP (MW)	132,006.5	Q=J*F
Reserve margin UCAP (MW)	24,373.5	R=G-P
Reserve cleared in excess of IRM UCAP (MW)	7,660.2	S=G-Q

Table 18 Net excess: 2022/2023 RPM Base Residual Auction

	UCAP (MW)						
	RTO	MAAC	EMAAC	ComEd	BGE	DEOK	
Cleared generation and DR plus make whole	139,666.7	62,731.2	28,318.8	18,499.8	2,295.0	1,971.8	A
CETL	NA	4,375.0	9,173.0	6,839.0	5,683.0	5,465.0	B
Reliability requirement	163,268.9	64,514.0	35,884.0	23,931.0	7,828.0	7,407.0	C
FRR peak load	28,535.5	0.0	0.0	0.0	0.0	827.5	D
PRD	230.0	230.0	40.0	0.0	80.0	0.0	E
FPR	1.0868	1.0868	1.0868	1.0868	1.0868	1.0868	F
Reliability requirement adjusted for FRR and PRD	132,006.5	64,264.0	35,840.5	23,931.0	7,741.1	6,507.7	G=C-D*F-E*F
Net excess/(deficit)	7,660.2	2,842.2	1,651.3	1,407.8	236.9	929.1	H=A+B-G

Table 19 Offered and cleared capacity by LDA, resource type, and season type: 2022/2023 RPM Base Residual Auction

		Offered UCAP (MW)			Cleared UCAP (MW)		
LDA	Resource Type	Annual	Summer	Winter	Annual	Summer	Winter
RTO	GEN	150,257.3	167.6	886.9	130,459.3	117.1	496.5
RTO	DR	10,071.0	305.1	35.3	8,369.9	305.1	35.3
RTO	EE	4,807.5	125.7	0.0	4,575.7	118.4	0.0
MAAC	GEN	65,658.9	1.2	134.3	60,003.3	0.2	81.6
MAAC	DR	2,885.8	141.4	0.0	2,537.0	141.4	0.0
MAAC	EE	1,909.3	36.9	0.0	1,909.3	32.8	0.0
EMAAC	GEN	30,247.2	1.2	47.6	27,253.0	0.2	0.0
EMAAC	DR	1,219.3	58.1	0.0	1,024.7	58.1	0.0
EMAAC	EE	1,056.1	19.0	0.0	1,056.1	17.5	0.0
ComEd	GEN	26,085.2	18.3	333.0	16,763.0	18.3	230.1
ComEd	DR	1,612.8	156.6	35.3	1,363.7	156.6	35.3
ComEd	EE	776.8	68.3	0.0	588.5	68.3	0.0
BGE	GEN	2,480.2	0.0	0.0	2,132.7	0.0	0.0
BGE	DR	186.1	0.0	0.0	162.6	0.0	0.0
BGE	EE	199.2	0.4	0.0	199.2	0.4	0.0
DEOK	GEN	2,850.3	0.0	0.0	1,789.6	0.0	0.0
DEOK	DR	237.0	0.0	0.0	185.1	0.0	0.0
DEOK	EE	143.6	2.9	0.0	140.1	2.9	0.0

Table 20 Weighted average sell offer prices by LDA, resource type, and season type: 2022/2023 RPM Base Residual Auction[154]

		Weighted-Average ($ per MW-day UCAP)		
LDA	Resource Type	Annual	Summer	Winter
RTO	GEN	$37.61	$34.05	$48.60
RTO	DR	$38.58	$11.03	NA
RTO	EE	$19.42	$55.38	
MAAC	GEN	$40.92	$123.91	$92.88
MAAC	DR	$43.80	$0.00	
MAAC	EE	$18.00	$11.33	
EMAAC	GEN	$41.36	$123.91	$189.00
EMAAC	DR	$50.79	$0.00	
EMAAC	EE	$17.25	$8.09	
ComEd	GEN	$69.23	$40.89	$34.90
ComEd	DR	$42.47	$21.50	NA
ComEd	EE	$32.08	$91.34	
BGE	GEN	$83.39		
BGE	DR	$49.39		
BGE	EE	$18.58	$0.00	
DEOK	GEN	$58.29		
DEOK	DR	$43.08		
DEOK	EE	$14.83	$0.00	

Table 21 Offered capacity by resource type, season type and price range as percent of Net CONE times B: 2022/2023 RPM Base Residual Auction[155]

	Offered UCAP (MW)								
	Annual			Summer			Winter		
Resource Type	0 Percent	>0 and <= 50 Percent	> 50 Percent	0 Percent	>0 and <= 50 Percent	> 50 Percent	0 Percent	>0 and <= 50 Percent	> 50 Percent
GEN	25,391.4	103,446.1	21,419.8	84.6	63.0	20.0	315.7	402.6	168.6
DR	551.8	8,505.1	1,014.1	222.8	82.3	0.0	0.0	35.3	0.0
EE	2,152.4	2,408.1	247.0	47.0	7.7	70.9	0.0	0.0	0.0

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

155 Data aggregated based on PJM confidentiality rules.

Table 22 Cleared MW by zone and resource type/fuel source: 2022/2023 RPM Base Residual Auction[156]

	Cleared UCAP (MW)										
Zone	DR	EE	Coal	Gas	Hydro	Nuclear	Oil	Solar	Solid Waste	Wind	Total
AECO	62.2	75.0	452.8	997.1	0.0	0.0	22.9	18.5	0.0	0.0	1,628.5
AEP	1,308.2	513.6	4,296.1	12,661.7	53.2	351.0	0.0	166.4	0.0	444.3	19,794.4
AP	669.0	219.3	4,780.4	4,178.6	121.6	0.0	0.0	65.0	0.0	113.5	10,147.4
ATSI	924.1	410.4	1,271.9	5,309.8	0.0	2,126.1	508.4	0.0	0.0	0.0	10,550.7
BGE	162.6	199.6	1,283.4	334.4	0.0	1,706.3	467.9	0.0	47.0	0.0	4,201.2
ComEd	1,555.5	656.8	1,502.6	9,934.3	0.0	4,598.6	240.0	0.0	0.0	735.9	19,223.7
DAY	210.5	91.3	0.0	889.2	0.0	0.0	34.0	33.3	0.0	0.0	1,258.3
DEOK	185.1	143.0	969.8	552.2	101.9	0.0	45.7	120.0	0.0	0.0	2,117.7
DLCO	148.6	86.1	0.0	235.0	0.0	1,775.1	16.4	0.0	0.0	0.0	2,261.2
Dominion	745.5	631.6	451.5	3,840.7	967.0	218.7	354.2	867.4	148.6	34.0	8,259.2
DPL	212.2	118.2	0.0	3,980.8	0.0	0.0	613.2	115.7	0.0	0.0	5,040.1
EKPC	285.4	0.0	1,628.8	1,217.7	130.2	0.0	0.0	0.0	0.0	0.0	3,262.1
External	0.0	0.0	954.9	159.9	343.7	99.5	0.0	0.0	0.0	0.0	1,558.0
JCPL	147.8	186.3	0.0	2,994.6	410.2	0.0	183.0	81.8	0.0	0.0	4,003.7
Met-Ed	230.7	88.6	113.8	2,534.0	16.1	0.0	395.9	38.2	53.6	0.0	3,470.9
OVEC	0.0	0.0	1,317.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,317.9
PECO	364.4	316.9	0.0	4,079.5	910.9	4,400.8	789.3	0.0	93.6	0.0	10,955.4
PENELEC	299.8	86.8	5,332.5	2,740.3	522.7	0.0	69.3	93.0	36.4	174.2	9,355.0
Pepco	240.8	259.0	0.0	3,324.7	0.0	0.0	299.7	0.8	46.5	0.0	4,171.5
PPL	661.7	234.7	2,243.7	7,878.9	568.6	2,440.9	41.0	7.6	8.3	33.3	14,118.7
PSEG	294.6	375.6	0.0	3,583.0	2.6	3,333.3	0.0	21.9	167.7	0.0	7,778.7
RECO	1.6	1.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.3
Total	8,710.3	4,694.1	26,600.1	71,426.4	4,148.7	21,050.3	4,080.9	1,629.6	601.7	1,535.1	144,477.3

156 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, 3,333.3 MW of the 7,778.7 cleared MW in the PSEG Zone were modeled and cleared in the EMAAC LDA.

Table 23 Uncleared generation offers by technology type and age: 2022/2023 RPM Base Residual Auction[157] [158]

	Uncleared UCAP (MW)		
Technology Type	Less Than or Equal to 40 Years Old	Greater than 40 Years Old	Total
Coal fired	1,513.2	5,011.2	6,524.4
Combined cycle	4,363.2	0.0	4,363.2
Combustion turbine	1,181.8	492.3	1,674.1
Nuclear	2,295.5	3,508.9	5,804.4
Oil or gas steam	0.0	567.9	567.9
Solar	601.3	0.0	601.3
Wind	490.7	0.0	490.7
Other	146.8	66.1	212.9
Total	10,592.5	9,646.4	20,238.9

157 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 2022/2023 BRA, waste coal resources are included in the coal fired category.

158 Data aggregated based on PJM confidentiality rules.

Table 24 Uncleared generation resources in multiple auctions[159] [160]

Technology	2022/2023 Uncleared UCAP (MW)	2022/2023 Number of Resources	2021/2022 Results for Same Set of Resources Uncleared UCAP (MW)	2021/2022 Results for Same Set of Resources Number of Resources	2020/2021 Results for Same Set of Resources Uncleared UCAP (MW)	2020/2021 Results for Same Set of Resources Number of Resources
Coal fired	6,524.4	35	727.4	24	1,250.2	21
Combined cycle	4,363.2	57	301.1	34	745.6	13
Combustion turbine	1,674.1	91	218.3	33	204.2	20
Solar	601.3	39	264.9	21	248.9	14
Wind	490.7	46	108.1	11	36.3	6
Other	6,585.2	40	4,610.2	20	671.5	16
Total	20,238.9	308	6,230.0	143	3,156.8	90

159 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 2022/2023 BRA, waste coal resources are included in the coal fired category.

160 Data aggregated based on PJM confidentiality rules.

Table 25 Offers greater than $35.00 per MW-day in total RTO supply curve: 2022/2023 RPM Base Residual Auction[161] [162]

Technology/Resource Type	Offered UCAP (MW)	Percent of Offers
Coal fired	17,882.8	32.1%
Nuclear	11,984.3	21.5%
Combined cycle	11,212.5	20.1%
Combustion turbine	4,454.6	8.0%
Demand Resource	3,329.9	6.0%
Oil or gas steam	2,899.1	5.2%
Hydro	1,287.6	2.3%
Solar	1,116.1	2.0%
Wind	834.2	1.5%
Energy Efficiency Resource	557.7	1.0%
Other generation	177.4	0.3%
Total	55,736.2	100.0%

Table 26 PJM LDA CETL and CETO values: 2021/2022 and 2022/2023 RPM Base Residual Auctions

	2021/2022 BRA			2022/2023 BRA			Change			
LDA	CETO	CETL	CETL to CETO Ratio	CETO	CETL	CETL to CETO Ratio	MW	Percent	MW	Percent
MAAC	(8,870.0)	4,019.0	(45.3%)	(7,440.0)	4,375.0	(58.8%)	1,430.0	(16.1%)	356.0	8.9%
EMAAC	2,500.0	9,000.0	360.0%	2,800.0	9,173.0	327.6%	300.0	12.0%	173.0	1.9%
SWMAAC	2,870.0	9,082.0	316.4%	4,120.0	8,310.0	201.7%	1,250.0	43.6%	(772.0)	(8.5%)
PSEG	5,620.0	6,902.0	122.8%	5,740.0	8,626.0	150.3%	120.0	2.1%	1,724.0	25.0%
PSEG North	2,410.0	3,180.0	132.0%	2,680.0	4,360.0	162.7%	270.0	11.2%	1,180.0	37.1%
DPL South	1,080.0	1,624.0	150.4%	1,480.0	2,053.0	138.7%	400.0	37.0%	429.0	26.4%
Pepco	1,550.0	6,915.0	446.1%	2,380.0	6,781.0	284.9%	830.0	53.5%	(134.0)	(1.9%)
ATSI	6,020.0	8,439.0	140.2%	4,610.0	9,119.0	197.8%	(1,410.0)	(23.4%)	680.0	8.1%
ATSI Cleveland	4,100.0	5,256.0	128.2%	3,310.0	5,229.0	158.0%	(790.0)	(19.3%)	(27.0)	(0.5%)
ComEd	(640.0)	5,574.0	(870.9%)	(2,130.0)	6,839.0	(321.1%)	(1,490.0)	232.8%	1,265.0	22.7%
BGE	4,470.0	6,005.0	134.3%	4,780.0	5,683.0	118.9%	310.0	6.9%	(322.0)	(5.4%)
PPL	(850.0)	6,609.0	(777.5%)	(500.0)	4,850.0	(970.0%)	350.0	(41.2%)	(1,759.0)	(26.6%)
DAY	2,480.0	3,502.0	141.2%	2,230.0	3,941.0	176.7%	(250.0)	(10.1%)	439.0	12.5%
DEOK	3,110.0	4,959.0	159.5%	2,710.0	5,465.0	201.7%	(400.0)	(12.9%)	506.0	10.2%

161 Effective for the 2017/2018 and subsequent delivery years, the ACR technology classes of waste coal small and large were eliminated and combined with subcritical and supercritical coal to form the Coal Fired ACR technology class. Waste coal resources were included in the other category in versions of this table prior to the 2017/2018 BRA. For the 2022/2023 BRA, waste coal resources are included in the coal fired category.

162 Data aggregated based on PJM confidentiality rules.

Figure 1 Shape of the VRR Curve relative to the reliability requirement: 2022/2023 RPM Base Residual Auction

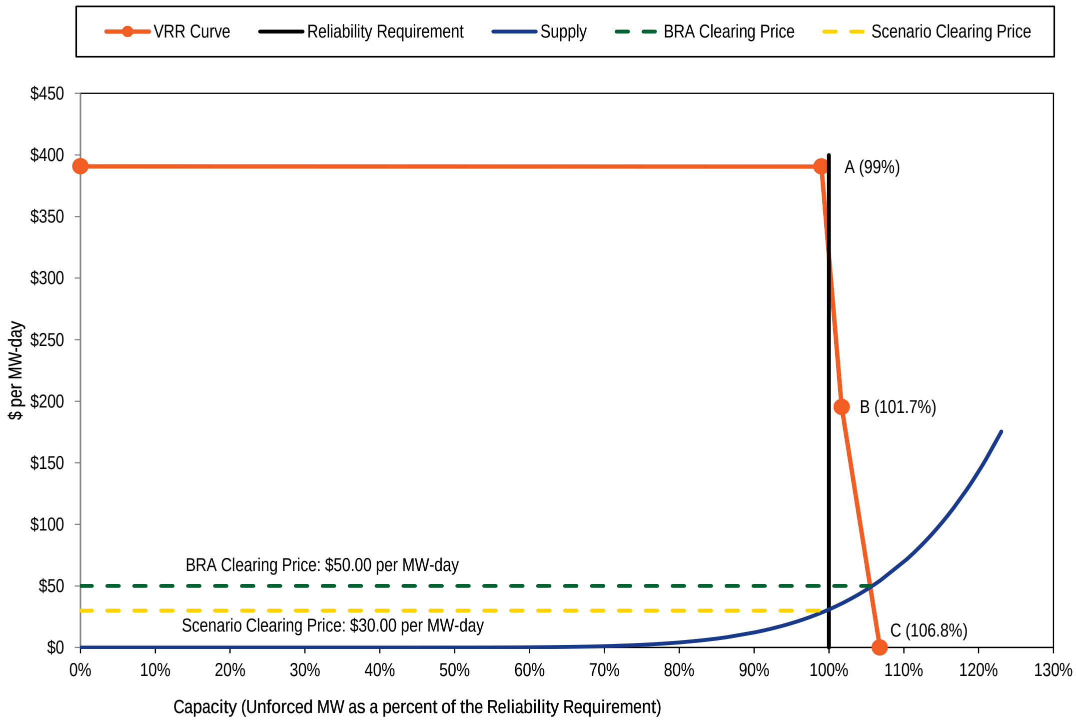


Table 27 Impact of using downward sloping VRR curve: 2022/2023 RPM Base Residual Auction

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	$50.00	143,790.5	$30.00	131,345.9
	Summer	$50.00	686.8	$30.00	660.8
	Winter	$50.00	686.8	$30.00	660.8
RTO Total			144,477.3		132,006.7
MAAC	Annual	$95.79	64,449.6	$75.00	59,724.5
	Summer	$95.79	164.6	$75.00	164.6
	Winter	$95.79	164.6	$75.00	164.6
MAAC Total			64,614.2		59,889.1
EMAAC	Annual	$97.86	29,333.8	$79.16	26,667.5
	Summer	$97.86	0.0	$79.16	0.0
	Winter	$97.86	0.0	$79.16	0.0
EMAAC Total			29,333.8		26,667.5
BGE	Annual	$126.50	2,494.5	$95.89	2,058.1
	Summer	$126.50	0.0	$95.89	0.0
	Winter	$126.50	0.0	$95.89	0.0
BGE Total			2,494.5		2,058.1
ComEd	Annual	$68.96	18,914.8	$55.00	16,835.3
	Summer	$68.96	282.7	$55.00	256.7
	Winter	$68.96	282.7	$55.00	256.7
ComEd Total			19,197.5		17,092.0
DEOK	Annual	$71.69	2,114.8	$46.48	1,637.1
	Summer	$71.69	0.0	$46.48	0.0
	Winter	$71.69	0.0	$46.48	0.0
DEOK Total			2,114.8		1,637.1

Table 28 Peak load forecast history[163]

	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	2021 / 2022	152,647.4	151,832.3	147,501.6	149,482.9		(0.5%)	(3.4%)	(2.1%)	
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%)	
Forecast Peak Load	2017 / 2018	164,478.8	160,092.2	154,377.3	153,230.1	145,635.9	(2.7%)	(6.1%)	(6.8%)	(11.5%)
Installed Reverve Margin		15.7%	15.70%	16.50%	16.60%		0.0%	5.1%	5.7%	
Pool Wide EFORd		5.65%	5.70%	5.93%	5.94%		0.9%	5.0%	5.1%	
Forecast Pool Requirement		1.0916	1.0911	1.0959	1.0967		(0.0%)	0.4%	0.5%	
Reliability Requirement		179,545.1	174,676.6	169,182.1	168,047.5		(2.7%)	(5.8%)	(6.4%)	
Forecast Peak Load	2016 / 2017	165,412.0	162,749.7	158,193.0	152,356.6	152,176.9	(1.6%)	(4.4%)	(7.9%)	(8.0%)
Installed Reverve Margin		15.6%	15.70%	15.50%	16.40%		0.6%	(0.6%)	5.1%	
Pool Wide EFORd		5.69%	5.64%	5.66%	5.91%		(0.9%)	(0.5%)	3.9%	
Forecast Pool Requirement		1.0902	1.0917	1.0896	1.0952		0.1%	(0.1%)	0.5%	
Reliability Requirement		180,332.2	177,673.8	172,367.1	166,860.9		(1.5%)	(4.4%)	(7.5%)	

163 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. Auctions using the revised load forecast model consist of the following: 2017/2018 (Second IA, Third IA), 2018/2019 (First IA, Second IA, Third IA), 2019/2020 (BRA, First IA), 2020/2021 BRA, 2021/2022 BRA.

Table 29 Impact of load forecast reduction: 2022/2023 RPM Base Residual Auction Scenario 2

		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	$50.00	143,790.5	$40.00	138,156.0
	Summer	$50.00	686.8	$40.00	655.8
	Winter	$50.00	686.8	$40.00	655.8
RTO Total			144,477.3		138,811.8
MAAC	Annual	$95.79	64,449.6	$79.18	61,853.5
	Summer	$95.79	164.6	$79.18	159.6
	Winter	$95.79	164.6	$79.18	159.6
MAAC Total			64,614.2		62,013.1
EMAAC	Annual	$97.86	29,333.8	$79.18	27,904.1
	Summer	$97.86	0.0	$79.18	0.0
	Winter	$97.86	0.0	$79.18	0.0
EMAAC Total			29,333.8		27,904.1
BGE	Annual	$126.50	2,494.5	$87.98	2,235.5
	Summer	$126.50	0.0	$87.98	0.0
	Winter	$126.50	0.0	$87.98	0.0
BGE Total			2,494.5		2,235.5
ComEd	Annual	$68.96	18,914.8	$55.00	17,955.0
	Summer	$68.96	282.7	$55.00	251.7
	Winter	$68.96	282.7	$55.00	251.7
ComEd Total			19,197.5		18,206.7
DEOK	Annual	$71.69	2,114.8	$52.17	1,886.8
	Summer	$71.69	0.0	$52.17	0.0
	Winter	$71.69	0.0	$52.17	0.0
DEOK Total			2,114.8		1,886.8

Table 30 Impact of ComEd CETL change: 2022/2023 RPM Base Residual Auction Scenario 3

		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	$50.00	143,790.5	$47.00	143,895.0
	Summer	$50.00	686.8	$47.00	686.8
	Winter	$50.00	686.8	$47.00	686.8
RTO Total			144,477.3		144,581.8
MAAC	Annual	$95.79	64,449.6	$95.79	64,449.5
	Summer	$95.79	164.6	$95.79	164.6
	Winter	$95.79	164.6	$95.79	164.6
MAAC Total			64,614.2		64,614.1
EMAAC	Annual	$97.86	29,333.8	$97.70	29,335.3
	Summer	$97.86	0.0	$97.70	0.0
	Winter	$97.86	0.0	$97.70	0.0
EMAAC Total			29,333.8		29,335.3
BGE	Annual	$126.50	2,494.5	$126.50	2,494.5
	Summer	$126.50	0.0	$126.50	0.0
	Winter	$126.50	0.0	$126.50	0.0
BGE Total			2,494.5		2,494.5
ComEd	Annual	$68.96	18,914.8	$93.80	20,015.0
	Summer	$68.96	282.7	$93.80	282.7
	Winter	$68.96	282.7	$93.80	282.7
ComEd Total			19,197.5		20,297.7
DEOK	Annual	$71.69	2,114.8	$71.69	2,114.8
	Summer	$71.69	0.0	$71.69	0.0
	Winter	$71.69	0.0	$71.69	0.0
DEOK Total			2,114.8		2,114.8

Table 31 Impact of Dominion FRR: 2022/2023 RPM Base Residual Auction Scenario 4

		Actual Auction Results		Dominion Stayed in the PJM Capacity Market	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$50.00	143,790.5	$55.98	162,788.4
	Summer	$50.00	686.8	$55.98	686.8
	Winter	$50.00	686.8	$55.98	686.8
RTO Total			144,477.3		163,475.2
MAAC	Annual	$95.79	64,449.6	$95.14	64,465.6
	Summer	$95.79	164.6	$95.14	160.3
	Winter	$95.79	164.6	$95.14	160.3
MAAC Total			64,614.2		64,625.9
EMAAC	Annual	$97.86	29,333.8	$97.70	29,335.3
	Summer	$97.86	0.0	$97.70	0.0
	Winter	$97.86	0.0	$97.70	0.0
EMAAC Total			29,333.8		29,335.3
BGE	Annual	$126.50	2,494.5	$126.50	2,494.5
	Summer	$126.50	0.0	$126.50	0.0
	Winter	$126.50	0.0	$126.50	0.0
BGE Total			2,494.5		2,494.5
ComEd	Annual	$68.96	18,914.8	$68.96	18,914.8
	Summer	$68.96	282.7	$68.96	282.7
	Winter	$68.96	282.7	$68.96	282.7
ComEd Total			19,197.5		19,197.5
DEOK	Annual	$71.69	2,114.8	$71.69	2,114.8
	Summer	$71.69	0.0	$71.69	0.0
	Winter	$71.69	0.0	$71.69	0.0
DEOK Total			2,114.8		2,114.8

Table 32 Impact of Intermittent Capacity overstatement: 2022/2023 RPM Base Residual Auction

Scenario 5

		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	$50.00	143,790.5	$58.40	143,846.7
	Summer	$50.00	686.8	$58.40	337.7
	Winter	$50.00	686.8	$58.40	337.7
RTO Total			144,477.3		144,184.4
MAAC	Annual	$95.79	64,449.6	$99.04	64,459.4
	Summer	$95.79	164.6	$99.04	96.2
	Winter	$95.79	164.6	$99.04	96.2
MAAC Total			64,614.2		64,555.6
EMAAC	Annual	$97.86	29,333.8	$99.04	29,398.0
	Summer	$97.86	0.0	$99.04	48.0
	Winter	$97.86	0.0	$99.04	48.0
EMAAC Total			29,333.8		29,446.0
BGE	Annual	$126.50	2,494.5	$126.50	2,494.5
	Summer	$126.50	0.0	$126.50	0.0
	Winter	$126.50	0.0	$126.50	0.0
BGE Total			2,494.5		2,494.5
ComEd	Annual	$68.96	18,914.8	$78.35	19,004.1
	Summer	$68.96	282.7	$78.35	131.1
	Winter	$68.96	282.7	$78.35	131.1
ComEd Total			19,197.5		19,135.2
DEOK	Annual	$71.69	2,114.8	$75.00	2,107.6
	Summer	$71.69	0.0	$75.00	0.0
	Winter	$71.69	0.0	$75.00	0.0
DEOK Total			2,114.8		2,107.6

Table 33 DR and EE statistics by LDA: 2021/2022 and 2022/2023 RPM Base Residual Auctions

		2021/2022 BRA			2022/2023 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	10,551.3	11,494.0	10,901.5	9,584.4	10,411.4	8,710.3	(966.9)	(9.2%)	(1,082.6)	(9.4%)	(2,191.2)	(20.1%)
RTO	EE	2,574.6	2,803.2	2,728.2	4,542.2	4,933.2	4,694.1	1,967.6	76.4%	2,130.0	76.0%	1,965.9	72.1%
MAAC	DR	3,213.4	3,498.6	3,280.7	2,787.7	3,027.2	2,678.4	(425.7)	(13.2%)	(471.5)	(13.5%)	(602.3)	(18.4%)
MAAC	EE	871.6	948.2	914.8	1,792.9	1,946.2	1,942.1	921.2	105.7%	998.0	105.3%	1,027.3	112.3%
EMAAC	DR	1,276.1	1,389.6	1,347.6	1,176.7	1,277.4	1,082.8	(99.4)	(7.8%)	(112.2)	(8.1%)	(264.8)	(19.7%)
EMAAC	EE	576.5	627.2	605.5	990.5	1,075.1	1,073.6	414.0	71.8%	447.9	71.4%	468.1	77.3%
SWMAAC	DR	584.4	635.8	523.4	406.0	441.1	403.4	(178.4)	(30.5%)	(194.8)	(30.6%)	(120.1)	(22.9%)
SWMAAC	EE	189.2	206.1	202.9	424.5	461.1	458.5	235.3	124.4%	255.0	123.7%	255.6	126.0%
DPL South	DR	64.3	70.0	66.3	47.0	51.0	48.4	(17.3)	(26.9%)	(19.0)	(27.1%)	(17.9)	(27.0%)
DPL South	EE	13.5	14.5	13.6	45.8	49.6	49.6	32.3	239.3%	35.1	242.1%	36.0	264.7%
PSEG	DR	381.7	415.9	407.9	361.9	393.0	294.6	(19.8)	(5.2%)	(22.9)	(5.5%)	(113.3)	(27.8%)
PSEG	EE	230.0	250.6	235.5	347.4	377.0	375.6	117.5	51.1%	126.5	50.5%	140.1	59.5%
PSEG North	DR	178.5	194.5	188.6	111.0	120.6	93.8	(67.5)	(37.8%)	(73.9)	(38.0%)	(94.8)	(50.3%)
PSEG North	EE	70.3	76.6	71.6	165.5	179.5	178.8	95.2	135.3%	102.9	134.3%	107.2	149.7%
Pepco	DR	314.3	342.1	286.2	234.6	255.0	240.8	(79.7)	(25.4%)	(87.1)	(25.5%)	(45.4)	(15.9%)
Pepco	EE	93.5	101.8	98.9	240.7	261.6	259.0	147.3	157.6%	159.8	156.9%	160.1	161.8%
ATSI	DR	1,120.8	1,221.2	1,142.4	1,035.4	1,124.8	924.1	(85.4)	(7.6%)	(96.4)	(7.9%)	(218.3)	(19.1%)
ATSI	EE	135.5	147.6	145.1	378.7	411.4	410.4	243.2	179.5%	263.8	178.6%	265.3	182.9%
ATSI Cleveland	DR	263.6	287.2	272.8	243.4	264.5	166.5	(20.2)	(7.7%)	(22.7)	(7.9%)	(106.3)	(39.0%)
ATSI Cleveland	EE	33.2	36.2	36.2	38.3	41.4	41.4	5.2	15.5%	5.2	14.4%	5.2	14.4%
ComEd	DR	1,828.7	1,992.8	1,918.2	1,660.8	1,804.6	1,555.5	(168.0)	(9.2%)	(188.2)	(9.4%)	(362.7)	(18.9%)
ComEd	EE	668.9	728.9	714.0	777.8	845.1	656.8	108.9	16.3%	116.1	15.9%	(57.2)	(8.0%)
BGE	DR	270.1	293.7	237.2	171.4	186.1	162.6	(98.7)	(36.5%)	(107.6)	(36.6%)	(74.6)	(31.5%)
BGE	EE	95.8	104.3	104.0	183.8	199.6	199.6	88.0	92.0%	95.2	91.3%	95.5	91.9%
PPL	DR	672.9	732.8	684.7	658.1	715.1	661.7	(14.8)	(2.2%)	(17.7)	(2.4%)	(23.0)	(3.4%)
PPL	EE	66.8	72.6	67.6	216.1	234.7	234.7	149.3	223.7%	162.1	223.3%	167.1	247.2%
DAY	DR	215.9	235.0	227.7	236.3	256.5	210.5	20.4	9.4%	21.5	9.1%	(17.2)	(7.6%)
DAY	EE	62.0	67.2	59.5	85.2	92.4	91.3	23.2	37.4%	25.1	37.4%	31.8	53.6%
DEOK	DR	196.8	214.0	201.8	218.3	237.0	185.1	21.5	10.9%	23.0	10.8%	(16.7)	(8.3%)
DEOK	EE	82.2	89.6	89.1	134.9	146.5	143.0	52.8	64.2%	57.0	63.6%	54.0	60.6%

Table 34 Impact of demand resources: 2022/2023 RPM Base Residual Auction Scenario 6

		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	$50.00	143,790.5	$84.08	137,822.6
	Summer	$50.00	686.8	$84.08	261.1
	Winter	$50.00	686.8	$84.08	261.1
RTO Total			144,477.3		138,083.7
MAAC	Annual	$95.79	64,449.6	$102.03	62,381.0
	Summer	$95.79	164.6	$102.03	57.9
	Winter	$95.79	164.6	$102.03	57.9
MAAC Total			64,614.2		62,438.9
EMAAC	Annual	$97.86	29,333.8	$102.03	28,765.5
	Summer	$97.86	0.0	$102.03	0.0
	Winter	$97.86	0.0	$102.03	0.0
EMAAC Total			29,333.8		28,765.5
BGE	Annual	$126.50	2,494.5	$126.50	2,290.8
	Summer	$126.50	0.0	$126.50	0.0
	Winter	$126.50	0.0	$126.50	0.0
BGE Total			2,494.5		2,290.8
ComEd	Annual	$68.96	18,914.8	$84.08	18,199.0
	Summer	$68.96	282.7	$84.08	135.4
	Winter	$68.96	282.7	$84.08	135.4
ComEd Total			19,197.5		18,334.4
DEOK	Annual	$71.69	2,114.8	$84.08	2,018.9
	Summer	$71.69	0.0	$84.08	0.0
	Winter	$71.69	0.0	$84.08	0.0
DEOK Total			2,114.8		2,018.9

Table 35 Impact of EE: 2022/2023 RPM Base Residual Auction

Scenario 7

		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	$50.00	143,790.5	$50.00	138,817.9
	Summer	$50.00	686.8	$50.00	451.9
	Winter	$50.00	686.8	$50.00	451.9
RTO Total			144,477.3		139,269.8
MAAC	Annual	$95.79	64,449.6	$93.57	62,424.2
	Summer	$95.79	164.6	$93.57	165.2
	Winter	$95.79	164.6	$93.57	165.2
MAAC Total			64,614.2		62,589.4
EMAAC	Annual	$97.86	29,333.8	$97.74	28,182.0
	Summer	$97.86	0.0	$97.74	0.0
	Winter	$97.86	0.0	$97.74	0.0
EMAAC Total			29,333.8		28,182.0
BGE	Annual	$126.50	2,494.5	$126.50	2,290.8
	Summer	$126.50	0.0	$126.50	0.0
	Winter	$126.50	0.0	$126.50	0.0
BGE Total			2,494.5		2,290.8
ComEd	Annual	$68.96	18,914.8	$65.00	18,143.7
	Summer	$68.96	282.7	$65.00	147.3
	Winter	$68.96	282.7	$65.00	147.3
ComEd Total			19,197.5		18,291.0
DEOK	Annual	$71.69	2,114.8	$71.69	1,964.5
	Summer	$71.69	0.0	$71.69	0.0
	Winter	$71.69	0.0	$71.69	0.0
DEOK Total			2,114.8		1,964.5

Table 36 Impact of incorrect EE addback MW: 2022/2023 RPM Base Residual Auction Scenario 8

		Actual Auction Results		EE Addback Equal to Cleared EE	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$50.00	143,790.5	$50.00	143,381.5
	Summer	$50.00	686.8	$50.00	686.8
	Winter	$50.00	686.8	$50.00	686.8
RTO Total			144,477.3		144,068.3
MAAC	Annual	$95.79	64,449.6	$94.38	64,319.3
	Summer	$95.79	164.6	$94.38	164.6
	Winter	$95.79	164.6	$94.38	164.6
MAAC Total			64,614.2		64,483.9
EMAAC	Annual	$97.86	29,333.8	$97.80	29,238.2
	Summer	$97.86	0.0	$97.80	0.0
	Winter	$97.86	0.0	$97.80	0.0
EMAAC Total			29,333.8		29,238.2
BGE	Annual	$126.50	2,494.5	$126.50	2,490.0
	Summer	$126.50	0.0	$126.50	0.0
	Winter	$126.50	0.0	$126.50	0.0
BGE Total			2,494.5		2,490.0
ComEd	Annual	$68.96	18,914.8	$65.00	18,732.2
	Summer	$68.96	282.7	$65.00	282.7
	Winter	$68.96	282.7	$65.00	282.7
ComEd Total			19,195.5		19,014.9
DEOK	Annual	$71.69	2,114.8	$71.69	2,104.6
	Summer	$71.69	0.0	$71.69	0.0
	Winter	$71.69	0.0	$71.69	0.0
DEOK Total			2,114.8		2,104.6

Table 37 Impact of price responsive demand (PRD): 2022/2023 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	$50.00	143,790.5	$50.00	144,040.4
	Summer	$50.00	686.8	$50.00	686.8
	Winter	$50.00	686.8	$50.00	686.8
RTO Total			144,477.3		144,727.2
MAAC	Annual	$95.79	64,449.6	$98.76	64,645.8
	Summer	$95.79	164.6	$98.76	164.6
	Winter	$95.79	164.6	$98.76	164.6
MAAC Total			64,614.2		64,810.4
EMAAC	Annual	$97.86	29,333.8	$98.76	29,372.4
	Summer	$97.86	0.0	$98.76	0.0
	Winter	$97.86	0.0	$98.76	0.0
EMAAC Total			29,333.8		29,372.4
BGE	Annual	$126.50	2,494.5	$126.50	2,581.4
	Summer	$126.50	0.0	$126.50	0.0
	Winter	$126.50	0.0	$126.50	0.0
BGE Total			2,494.5		2,581.4
ComEd	Annual	$68.96	18,914.8	$68.96	18,914.8
	Summer	$68.96	282.7	$68.96	282.7
	Winter	$68.96	282.7	$68.96	282.7
ComEd Total			19,197.5		19,197.5
DEOK	Annual	$71.69	2,114.8	$71.69	2,114.8
	Summer	$71.69	0.0	$71.69	0.0
	Winter	$71.69	0.0	$71.69	0.0
DEOK Total			2,114.8		2,114.8

Table 38 Impact of seasonal products: 2022/2023 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	$50.00	143,790.5	$54.79	144,052.6
	Summer	$50.00	686.8	$54.79	0.0
	Winter	$50.00	686.8	$54.79	0.0
RTO Total			144,477.3		144,052.6
MAAC	Annual	$95.79	64,449.6	$97.72	64,502.6
	Summer	$95.79	164.6	$97.72	0.0
	Winter	$95.79	164.6	$97.72	0.0
MAAC Total			64,614.2		64,502.6
EMAAC	Annual	$97.86	29,333.8	$97.72	29,347.8
	Summer	$97.86	0.0	$97.72	0.0
	Winter	$97.86	0.0	$97.72	0.0
EMAAC Total			29,333.8		29,347.8
BGE	Annual	$126.50	2,494.5	$126.50	2,493.8
	Summer	$126.50	0.0	$126.50	0.0
	Winter	$126.50	0.0	$126.50	0.0
BGE Total			2,494.5		2,493.8
ComEd	Annual	$68.96	18,914.8	$77.56	19,002.0
	Summer	$68.96	282.7	$77.56	0.0
	Winter	$68.96	282.7	$77.56	0.0
ComEd Total			19,197.5		19,002.0
DEOK	Annual	$71.69	2,114.8	$71.69	2,108.9
	Summer	$71.69	0.0	$71.69	0.0
	Winter	$71.69	0.0	$71.69	0.0
DEOK Total			2,114.8		2,108.9

Table 39 Impact of seasonal matching across LDAs: 2022/2023 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	$50.00	143,790.5	$53.25	143,930.3
	Summer	$50.00	686.8	$53.25	432.9
	Winter	$50.00	686.8	$53.25	432.9
RTO Total			144,477.3		144,363.2
MAAC	Annual	$95.79	64,449.6	$97.75	64,462.4
	Summer	$95.79	164.6	$97.75	116.0
	Winter	$95.79	164.6	$97.75	116.0
MAAC Total			64,614.2		64,578.4
EMAAC	Annual	$97.86	29,333.8	$97.75	29,305.7
	Summer	$97.86	0.0	$97.75	96.0
	Winter	$97.86	0.0	$97.75	96.0
EMAAC Total			29,333.8		29,401.7
BGE	Annual	$126.50	2,494.5	$126.50	2,494.5
	Summer	$126.50	0.0	$126.50	0.0
	Winter	$126.50	0.0	$126.50	0.0
BGE Total			2,494.5		2,494.5
ComEd	Annual	$68.96	18,914.8	$68.96	18,914.8
	Summer	$68.96	282.7	$68.96	282.7
	Winter	$68.96	282.7	$68.96	282.7
ComEd Total			19,197.5		19,197.5
DEOK	Annual	$71.69	2,114.8	$71.69	2,114.8
	Summer	$71.69	0.0	$71.69	0.0
	Winter	$71.69	0.0	$71.69	0.0
DEOK Total			2,114.8		2,114.8

Table 40 RPM imports: 2007/2008 through 2022/2023 RPM Base Residual Auctions

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

Table 41 Impact of External Generation: 2022/2023 RPM Base Residual Auction Scenario 12

		Actual Auction Results		No Offers from External Generation Capacity	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$50.00	143,790.5	$65.08	143,245.8
	Summer	$50.00	686.8	$65.08	701.2
	Winter	$50.00	686.8	$65.08	701.2
RTO Total			144,477.3		143,947.0
MAAC	Annual	$95.79	64,449.6	$95.79	64,450.1
	Summer	$95.79	159.6	$95.79	159.6
	Winter	$95.79	164.6	$95.79	159.6
MAAC Total			64,609.2		64,609.7
EMAAC	Annual	$97.86	29,333.8	$97.90	29,331.8
	Summer	$97.86	0.0	$97.90	0.0
	Winter	$97.86	0.0	$97.90	0.0
EMAAC Total			29,333.8		29,331.8
BGE	Annual	$126.50	2,494.5	$126.50	2,494.5
	Summer	$126.50	0.0	$126.50	0.0
	Winter	$126.50	0.0	$126.50	0.0
BGE Total			2,494.5		2,494.5
ComEd	Annual	$68.96	18,914.8	$68.96	18,914.8
	Summer	$68.96	282.7	$68.96	282.7
	Winter	$68.96	279.6	$68.96	282.7
ComEd Total			19,194.4		19,197.5
DEOK	Annual	$71.69	2,114.8	$71.69	2,114.8
	Summer	$71.69	0.0	$71.69	0.0
	Winter	$71.69	0.0	$71.69	0.0
DEOK Total			2,114.8		2,114.8

Table 42 Impact of DR, EE, PRD, seasonal resources, capacity imports, and intermittent capacity overstatement: 2022/2023 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	$50.00	143,790.5	$133.47	136,611.0
	Summer	$50.00	686.8	$133.47	0.0
	Winter	$50.00	686.8	$133.47	0.0
RTO Total			144,477.3		136,611.0
MAAC	Annual	$95.79	64,449.6	$133.47	62,426.3
	Summer	$95.79	164.6	$133.47	0.0
	Winter	$95.79	164.6	$133.47	0.0
MAAC Total			64,614.2		62,426.3
EMAAC	Annual	$97.86	29,333.8	$133.47	28,934.5
	Summer	$97.86	0.0	$133.47	0.0
	Winter	$97.86	0.0	$133.47	0.0
EMAAC Total			29,333.8		28,934.5
BGE	Annual	$126.50	2,494.5	$135.00	2,357.5
	Summer	$126.50	0.0	$135.00	0.0
	Winter	$126.50	0.0	$135.00	0.0
BGE Total			2,494.5		2,357.5
ComEd	Annual	$68.96	18,914.8	$133.47	20,232.4
	Summer	$68.96	282.7	$133.47	0.0
	Winter	$68.96	282.7	$133.47	0.0
ComEd Total			19,197.5		20,232.4
DEOK	Annual	$71.69	2,114.8	$133.47	2,565.8
	Summer	$71.69	0.0	$133.47	0.0
	Winter	$71.69	0.0	$133.47	0.0
DEOK Total			2,114.8		2,565.8

Table 43 Impact of low MOPR offers: 2022/2023 RPM Base Residual Auction Scenario 14

		Actual Auction Results		MMU MOPR Determinations Applied	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$50.00	143,790.5	$54.79	143,682.3
	Summer	$50.00	686.8	$54.79	627.4
	Winter	$50.00	686.8	$54.79	627.4
RTO Total			144,477.3		144,309.7
MAAC	Annual	$95.79	64,449.6	$98.72	64,397.2
	Summer	$95.79	164.6	$98.72	163.9
	Winter	$95.79	164.6	$98.72	163.9
MAAC Total			64,614.2		64,561.1
EMAAC	Annual	$97.86	29,333.8	$99.01	29,322.9
	Summer	$97.86	0.0	$99.01	0.0
	Winter	$97.86	0.0	$99.01	0.0
EMAAC Total			29,333.8		29,322.9
BGE	Annual	$126.50	2,494.5	$126.50	2,494.5
	Summer	$126.50	0.0	$126.50	0.0
	Winter	$126.50	0.0	$126.50	0.0
BGE Total			2,494.5		2,494.5
ComEd	Annual	$68.96	18,914.8	$71.02	18,901.1
	Summer	$68.96	282.7	$71.02	282.7
	Winter	$68.96	282.7	$71.02	282.7
ComEd Total			19,197.5		19,183.8
DEOK	Annual	$71.69	2,114.8	$73.29	2,111.3
	Summer	$71.69	0.0	$73.29	0.0
	Winter	$71.69	0.0	$73.29	0.0
DEOK Total			2,114.8		2,111.3

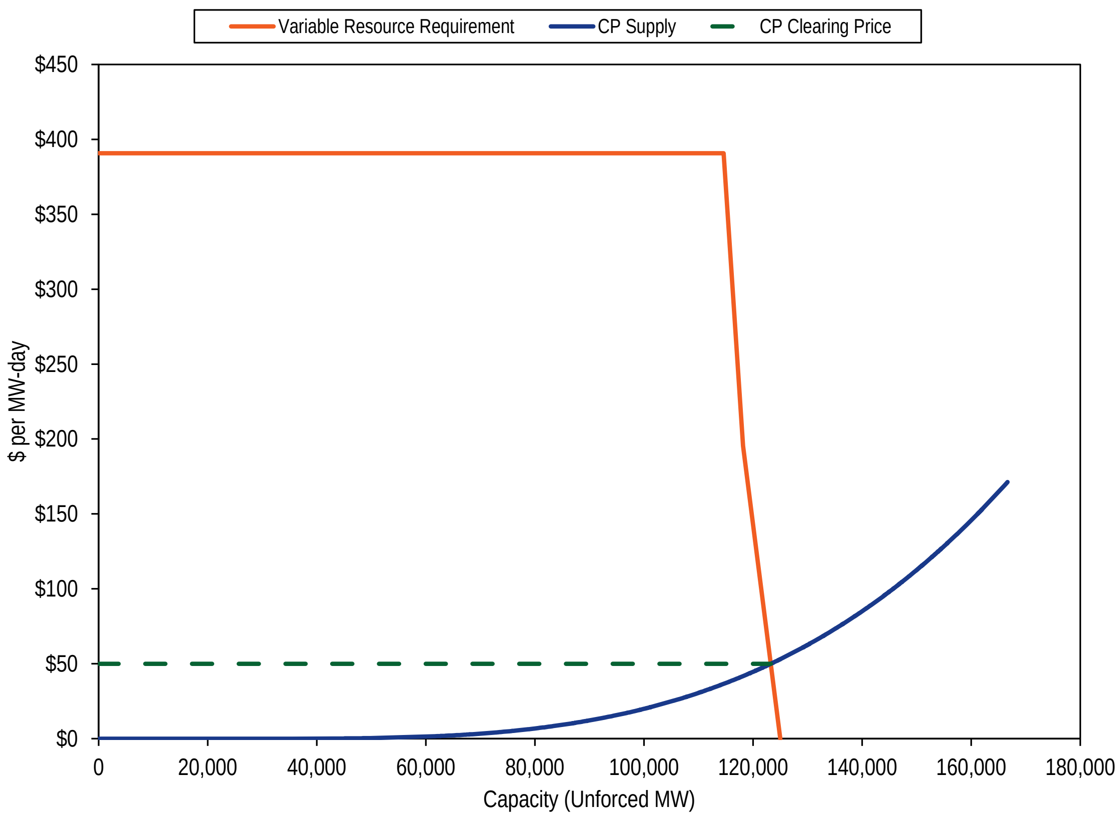
Table 44 Impact of Nuclear offers: 2022/2023 RPM Base Residual Auction Scenario 15

		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	Cleared UCAP (MW)
RTO	Annual	$50.00	143,790.5	$41.01	144,233.1
	Summer	$50.00	686.8	$41.01	557.7
	Winter	$50.00	686.8	$41.01	557.7
RTO Total			144,477.3		144,790.8
MAAC	Annual	$95.79	64,449.6	$94.42	64,474.3
	Summer	$95.79	164.6	$94.42	164.6
	Winter	$95.79	164.6	$94.42	164.6
MAAC Total			64,614.2		64,638.9
EMAAC	Annual	$97.86	29,333.8	$94.42	29,388.7
	Summer	$97.86	0.0	$94.42	0.0
	Winter	$97.86	0.0	$94.42	0.0
EMAAC Total			29,333.8		29,388.7
BGE	Annual	$126.50	2,494.5	$126.50	2,494.5
	Summer	$126.50	0.0	$126.50	0.0
	Winter	$126.50	0.0	$126.50	0.0
BGE Total			2,494.5		2,494.5
ComEd	Annual	$68.96	18,914.8	$41.01	20,888.4
	Summer	$68.96	282.7	$41.01	153.6
	Winter	$68.96	282.7	$41.01	153.6
ComEd Total			19,197.5		21,042.0
DEOK	Annual	$71.69	2,114.8	$71.69	2,114.8
	Summer	$71.69	0.0	$71.69	0.0
	Winter	$71.69	0.0	$71.69	0.0
DEOK Total			2,114.8		2,114.8

Table 45 Impact of noncompetitive offers: 2022/2023 RPM Base Residual Auction Scenario 16

		Actual Auction Results		Noncompetitive Offers Capped at net ACR	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$50.00	143,790.5	$50.00	143,871.5
	Summer	$50.00	686.8	$50.00	605.8
	Winter	$50.00	686.8	$50.00	605.8
RTO Total			144,477.3		144,477.3
MAAC	Annual	$95.79	64,449.6	$93.51	64,495.8
	Summer	$95.79	164.6	$93.51	159.6
	Winter	$95.79	164.6	$93.51	159.6
MAAC Total			64,614.2		64,655.4
EMAAC	Annual	$97.86	29,333.8	$94.60	29,364.8
	Summer	$97.86	0.0	$94.60	0.0
	Winter	$97.86	0.0	$94.60	0.0
EMAAC Total			29,333.8		29,364.8
BGE	Annual	$126.50	2,494.5	$100.00	2,539.9
	Summer	$126.50	0.0	$100.00	0.0
	Winter	$126.50	0.0	$100.00	0.0
BGE Total			2,494.5		2,539.9
ComEd	Annual	$68.96	18,914.8	$51.64	19,110.7
	Summer	$68.96	282.7	$51.64	201.7
	Winter	$68.96	282.7	$51.64	201.7
ComEd Total			19,197.5		19,312.4
DEOK	Annual	$71.69	2,114.8	$50.00	2,222.5
	Summer	$71.69	0.0	$50.00	0.0
	Winter	$71.69	0.0	$50.00	0.0
DEOK Total			2,114.8		2,222.5

Figure 2 RTO market supply/demand curves: 2022/2023 RPM Base Residual Auction[164] [165]



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[164] 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.

[165] The VRR curve excludes incremental demand which cleared in MAAC, EMAAC, ComEd, BGE, and DEOK.

MAAC LDA Market Results

Table 46 shows total MAAC LDA offer data for the 2022/2023 RPM Base Residual Auction. Total internal MAAC LDA unforced capacity, excluding generation winter capacity, of 73,638.5 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 11, MAAC LDA unforced internal capacity decreased 2,721.7 MW from 76,360.2 MW in the 2021/2022 BRA as a result of net generation capacity modifications (-2,880.4 MW), net DR modifications (-615.0 MW), and net EE modifications (994.0 MW), the EFORd effect due to higher sell offer EFORds (-205.7 MW), and the DR and EE effect due to a lower Load Management UCAP conversion factor (-14.6 MW). As shown in Table 13, total internal MAAC unforced winter capacity increased by 92.4 MW for November through April of the 2022/2023 Delivery Year.

All imports offered in the auction from areas external to PJM are modeled as supply in the rest of RTO.[166] Total internal MAAC LDA capacity was reduced by FRR commitments of 270.0 MW, resulting in MAAC LDA RPM capacity of 73,456.5 MW. RPM capacity was reduced by 674.0 MW of exports, 0.0 MW of FRR optional volumes not offered, 651.3 MW excused from the RPM must offer requirement, 118.3 MW of Planned Generation Capacity Resources which were not subject to the RPM must offer requirement, and 719.9 MW of intermittent resources and 229.7 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 (643.1 MW) and capacity resources with state subsidy that could not participate because a resource specific MOPR floor was not sought and the applicable default MOPR floor exceeded the default offer cap (8.2 MW). Subtracting 282.1 MW of DR and EE not offered and 13.5 MW of unoffered generation winter capacity resulted in available unforced capacity in MAAC LDA of 70,767.7 MW.[167] 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 2022/2023 BRA. Of the 64,705.6 MW cleared in MAAC LDA, 47,587.6 MW were cleared in the RTO before

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166 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).

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

MAAC LDA became constrained. Once the constraint was binding, based on the 4,375.0 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, 17,118.0 MW cleared, which resulted in a clearing price for Capacity Performance Resources of $95.79 per MW-day, as shown in Figure 4. The clearing price was determined by the intersection of the incremental supply and VRR curve.

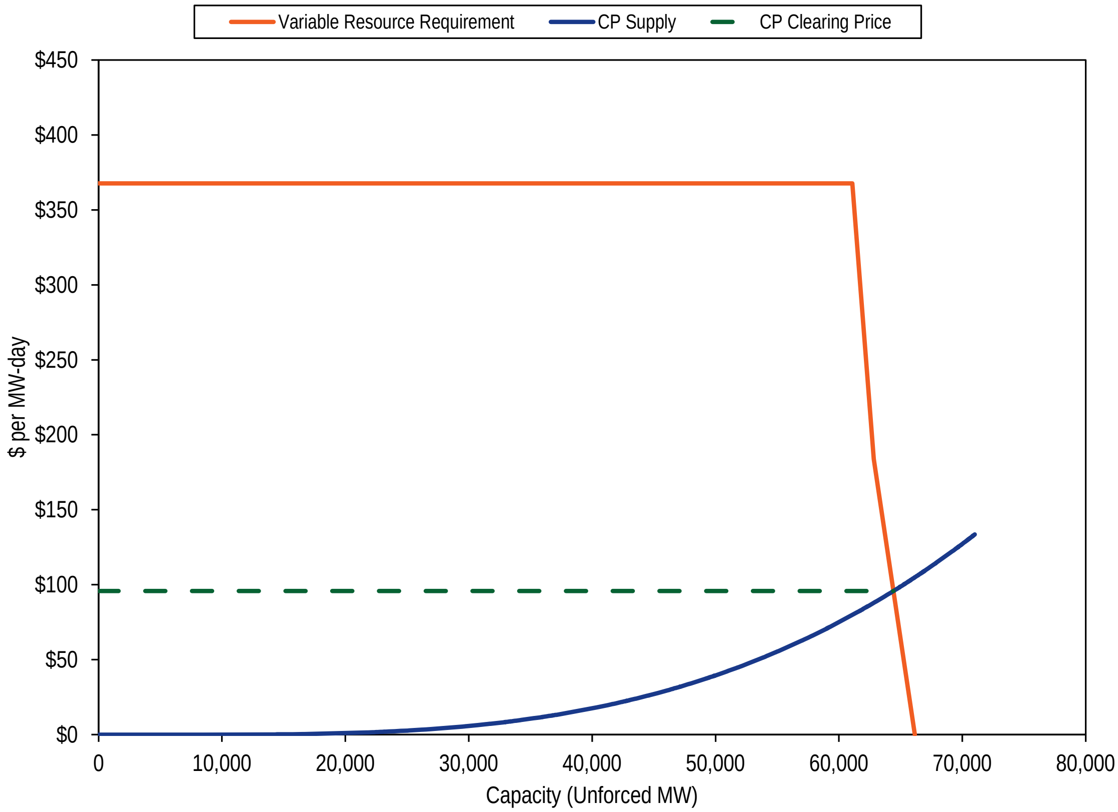
As shown in Table 18, the 62,731.2 MW of cleared and uplift generation and DR for MAAC LDA and 4,375.0 MW CETL resulted in a net excess of 2,842.2 MW.

Table and Figure for MAAC LDA

Table 46 MAAC LDA offer statistics: 2022/2023 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	71,182.9	68,383.1		
DR capacity	3,013.5	3,272.6		
EE capacity	1,826.6	1,982.8		
Generation winter capacity	88.0	88.0		
Total internal MAAC LDA capacity	76,111.0	73,726.5		
FRR	(277.7)	(270.0)		
Imports	0.0	0.0		
RPM capacity	75,833.3	73,456.5		
Exports	(674.0)	(674.0)		
FRR optional	0.0	0.0		
Excused Existing Generation Capacity Resources	(750.7)	(651.3)		
Unoffered Planned Generation Capacity Resources	(144.6)	(118.3)		
Unoffered Intermittent Resources	(739.6)	(719.9)		
Unoffered Capacity Storage Resources	(230.0)	(229.7)		
Unoffered generation winter capacity	(13.5)	(13.5)		
Unoffered DR and EE	(259.6)	(282.1)		
Available	73,021.4	70,767.8	100.0%	100.0%
Generation offered	68,440.8	65,794.4	93.7%	93.0%
DR offered	2,787.7	3,027.2	3.8%	4.3%
EE offered	1,792.9	1,946.2	2.5%	2.8%
Total offered	73,021.4	70,767.7	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: 2022/2023 RPM Base Residual Auction[168]



EMAAC LDA Market Results

Table 47 shows total EMAAC LDA offer data for the 2022/2023 RPM Base Residual Auction. Total internal EMAAC LDA unforced capacity, excluding generation winter capacity, of 34,204.6 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 11, EMAAC LDA unforced internal capacity increased 409.0 MW from 33,795.6 MW in the 2021/2022 BRA as a result of net generation capacity modifications (-100.1 MW), net DR modifications (-160.4 MW), and net EE modifications (447.0 MW), the EFORd effect due to lower sell offer EFORds (229.2 MW), and the DR and EE effect due to a lower Load Management UCAP conversion factor (-6.7 MW). As shown in Table 13,

168 The VRR curve is reduced by the CETL and incremental demand which cleared in EMAAC and BGE.

total internal EMAAC unforced winter capacity increased by 0.0 MW for November through April of the 2022/2023 Delivery Year.

All imports offered in the auction from areas external to PJM are modeled as supply in the rest of RTO.[169] Total internal EMAAC LDA capacity was reduced by FRR commitments of 0.0 MW, resulting in EMAAC LDA RPM capacity of 34,204.6 MW. RPM capacity was reduced by 674.0 MW of exports, 0.0 MW of FRR optional volumes not offered, 8.2 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 537.1 MW of intermittent resources and 229.7 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 capacity resources with state subsidy that could not participate because a resource specific MOPR floor was not sought and the applicable default MOPR floor exceeded the default offer cap (8.2 MW). Subtracting 107.1 MW of DR and EE not offered and 0.0 MW of unoffered generation winter capacity resulted in available unforced capacity in EMAAC LDA of 32,648.5 MW.[170] After accounting for these exceptions, all capacity resources in EMAAC were offered in the RPM Auction.

The EMAAC LDA import limit was a binding constraint in the 2022/2023 BRA. Of the 29,409.6 MW cleared in EMAAC LDA, 29,208.0 MW were cleared in the MAAC LDA before EMAAC LDA became constrained. Once the constraint was binding, based on the 9,173.0 MW CETL value, only the incremental supply located in EMAAC LDA was available to meet the incremental demand in the LDA. Of the incremental supply, 201.6 MW cleared, which resulted in a clearing price for Capacity Performance Resources of $97.86 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 18, the 28,318.8 MW of cleared and uplift generation and DR for EMAAC LDA and 9,173.0 MW CETL resulted in a net excess of 1,651.3 MW.

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169 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).

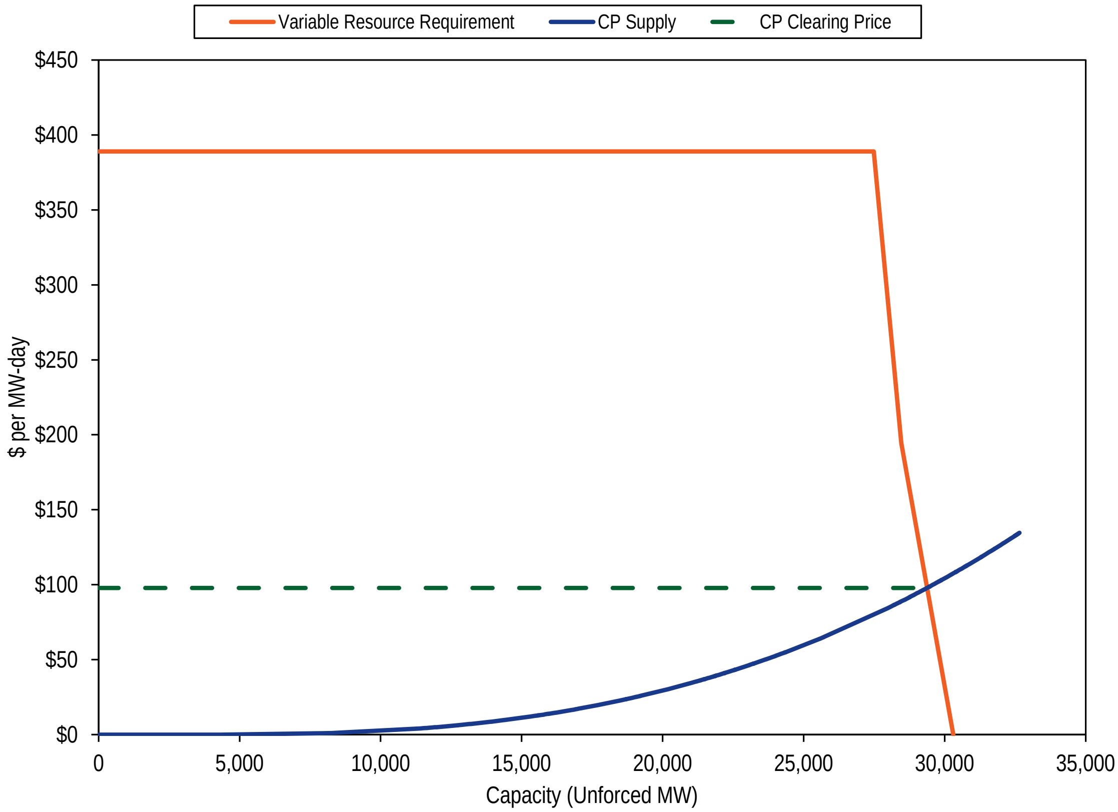
170 Unoffered DR and EE MW include PJM approved DR and EE plans that were not offered in the auction.

Table and Figure for EMAAC LDA

Table 47 EMAAC LDA offer statistics: 2022/2023 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	32,601.1	31,745.0		
DR capacity	1,257.9	1,365.6		
EE capacity	1,007.9	1,094.0		
Generation winter capacity	0.0	0.0		
Total internal EMAAC LDA capacity	34,866.9	34,204.6		
FRR	0.0	0.0		
Imports	0.0	0.0		
RPM capacity	34,866.9	34,204.6		
Exports	(674.0)	(674.0)		
FRR optional	0.0	0.0		
Excused Existing Generation Capacity Resources	(9.0)	(8.2)		
Unoffered Planned Generation Capacity Resources	0.0	0.0		
Unoffered Intermittent Resources	(548.9)	(537.1)		
Unoffered Capacity Storage Resources	(230.0)	(229.7)		
Unoffered generation winter capacity	0.0	0.0		
Unoffered DR and EE	(98.6)	(107.1)		
Available	33,306.4	32,648.5	100.0%	100.0%
Generation offered	31,139.2	30,296.0	93.5%	92.8%
DR offered	1,176.7	1,277.4	3.5%	3.9%
EE offered	990.5	1,075.1	3.0%	3.3%
Total offered	33,306.4	32,648.4	100.0%	100.0%
Unoffered Existing Generation Capacity Resources	0.0	0.0	0.0%	0.0%

Figure 4 EMAAC LDA market supply/demand curves: 2022/2023 RPM Base Residual Auction[171]



ComEd LDA Market Results

Table 48 shows total ComEd LDA offer data for the 2022/2023 RPM Base Residual Auction. Total internal ComEd LDA unforced capacity, excluding generation winter capacity, of 29,664.4 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 11, ComEd LDA unforced internal capacity increased 1,078.5 MW from 28,585.9 MW in the 2021/2022 BRA as a result of net generation capacity modifications (1,199.9 MW), net DR modifications (-163.8 MW), and net EE modifications (127.3 MW), the EFORd effect due to higher sell offer EFORds (-76.7 MW), and the DR and EE effect due to a lower Load Management UCAP conversion factor (-8.2 MW). As shown in Table 13, total internal ComEd unforced winter capacity increased by 386.7 MW for

[171] The VRR curve is reduced by the CETL.

November through April of the 2022/2023 Delivery Year as a result of net generation winter capacity modifications (386.7 MW).

All imports offered in the auction from areas external to PJM are modeled as supply in the rest of RTO.[172] Total internal ComEd LDA capacity was reduced by FRR commitments of 0.0 MW, resulting in ComEd LDA RPM capacity of 30,035.2 MW. RPM capacity was reduced by 544.0 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 158.0 MW of intermittent resources and 0.0 MW of capacity storage resources which were not subject to the CP must offer requirement. Subtracting 186.0 MW of DR and EE not offered and 61.0 MW of unoffered generation winter capacity resulted in available unforced capacity in ComEd LDA of 29,086.2 MW.[173] After accounting for these exceptions, all capacity resources in ComEd LDA were offered in the RPM Auction.

The ComEd LDA import limit was a binding constraint in the 2022/2023 BRA. Of the 19,223.7 MW cleared in ComEd LDA, 15,144.7 MW were cleared in the RTO before ComEd LDA became constrained. Once the constraint was binding, based on the 6,839.0 MW CETL value, only the incremental supply located in ComEd LDA was available to meet the incremental demand in the LDA. Of the incremental supply, 4,079.0 MW cleared, which resulted in a clearing price for Capacity Performance Resources of $68.96 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 18, the 18,499.8 MW of cleared and uplift generation and DR for ComEd LDA and 6,839.0 MW CETL resulted in a net excess of 1,407.8 MW.

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172 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).

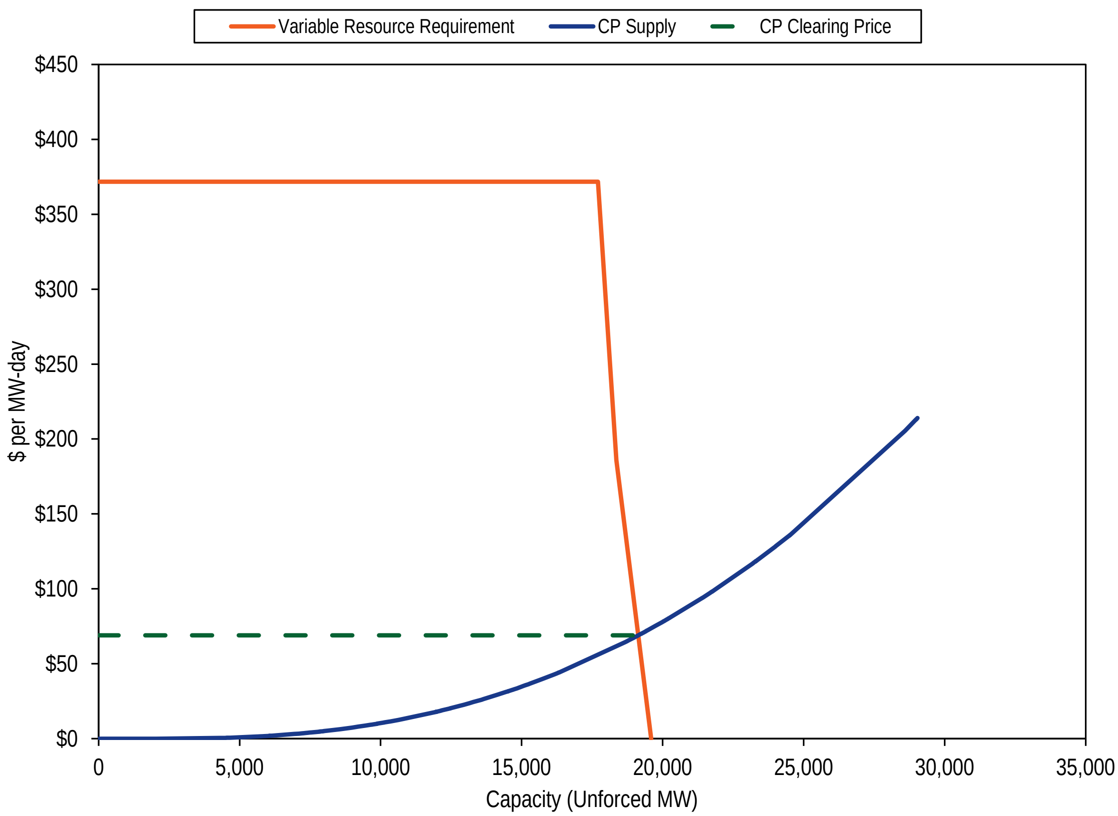
173 Unoffered DR and EE MW include PJM approved DR and EE plans that were not offered in the auction.

Table and Figure for ComEd LDA

Table 48 ComEd LDA offer statistics: 2022/2023 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	27,382.9	26,828.7		
DR capacity	1,770.1	1,923.4		
EE capacity	839.6	912.2		
Generation winter capacity	370.9	370.9		
Total internal ComEd LDA capacity	30,363.5	30,035.2		
FRR	0.0	0.0		
Imports	0.0	0.0		
RPM capacity	30,363.5	30,035.2		
Exports	(545.9)	(544.0)		
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	(158.0)	(158.0)		
Unoffered Capacity Storage Resources	0.0	0.0		
Unoffered generation winter capacity	(61.0)	(61.0)		
Unoffered DR and EE	(171.1)	(186.0)		
Available	29,427.4	29,086.2	100.0%	100.0%
Generation offered	26,988.8	26,436.5	91.7%	90.9%
DR offered	1,660.8	1,804.6	5.6%	6.2%
EE offered	777.8	845.1	2.6%	2.9%
Total offered	29,427.4	29,086.2	100.0%	100.0%
Unoffered Existing Generation Capacity Resources	0.0	0.0	0.0%	0.0%

Figure 5 ComEd LDA market supply/demand curves: 2022/2023 RPM Base Residual Auction[174]



BGE LDA Market Results

Table 49 shows total BGE LDA offer data for the 2022/2023 RPM Base Residual Auction. Total internal BGE LDA unforced capacity, excluding generation winter capacity, of 3,003.2 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 11, BGE LDA unforced internal capacity decreased 835.0 MW from 3,838.2 MW in the 2021/2022 BRA as a result of net generation capacity modifications (-737.8 MW), net DR modifications (-197.9 MW), and net EE modifications (95.3 MW), the EFORd effect due to lower sell offer EFORds (6.5 MW), and the DR and EE effect due to a lower Load Management UCAP conversion factor (-1.1 MW). As shown in Table 13, total internal BGE unforced winter capacity increased by 0.0 MW for November through April of the 2022/2023 Delivery Year.

174 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.[175] Total internal BGE LDA capacity was reduced by FRR commitments of 0.0 MW, resulting in BGE LDA RPM capacity of 3,003.2 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, 118.3 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 19.0 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 2,865.9 MW.[176] 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 2022/2023 BRA. Of the 2,494.9 MW cleared in BGE LDA, 2,253.2 MW were cleared in the MAAC LDA before BGE LDA became constrained. Once the constraint was binding, based on the 5,683.0 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, 241.7 MW cleared, which resulted in a clearing price for Capacity Performance Resources of $126.50 per MW-day, as shown in Figure 6. The clearing price was determined by the intersection of the incremental supply and VRR curve.

As shown in Table 18, the 2,295.0 MW of cleared and uplift generation and DR for BGE LDA and 5,683.0 MW CETL resulted in a net excess of 236.9 MW.

175 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).

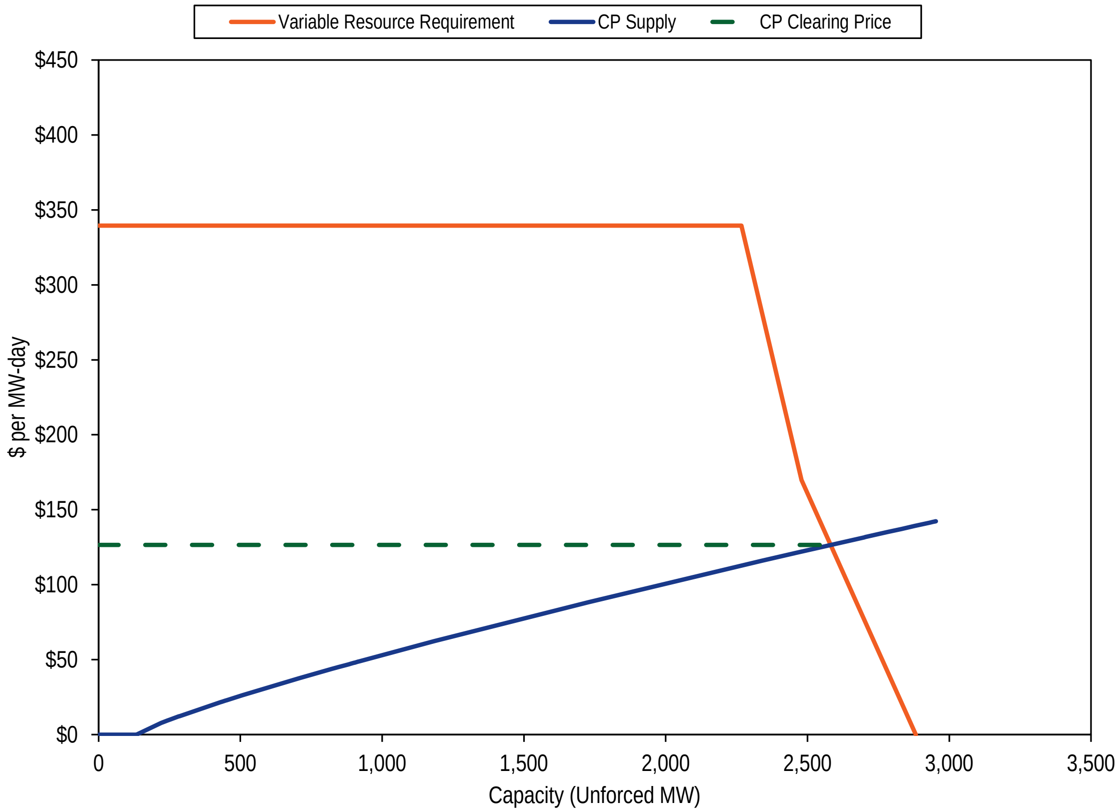
176 Unoffered DR and EE MW include PJM approved DR and EE plans that were not offered in the auction.

Table and Figure for BGE LDA

Table 49 BGE LDA offer statistics: 2022/2023 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	2,789.3	2,598.5		
DR capacity	188.6	204.8		
EE capacity	184.1	199.9		
Generation winter capacity	0.0	0.0		
Total internal BGE LDA capacity	3,162.0	3,003.2		
FRR	0.0	0.0		
Imports	0.0	0.0		
RPM capacity	3,162.0	3,003.2		
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	(144.6)	(118.3)		
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	(17.5)	(19.0)		
Available	2,999.9	2,865.9	100.0%	100.0%
Generation offered	2,644.7	2,480.2	88.2%	86.5%
DR offered	171.4	186.1	5.7%	6.5%
EE offered	183.8	199.6	6.1%	7.0%
Total offered	2,999.9	2,865.9	100.0%	100.0%
Unoffered Existing Generation Capacity Resources	0.0	0.0	0.0%	0.0%

Figure 6 BGE LDA market supply/demand curves: 2022/2023 RPM Base Residual Auction[177]



DEOK LDA Market Results

Table 50 shows total DEOK LDA offer data for the 2022/2023 RPM Base Residual Auction. Total internal DEOK LDA unforced capacity, excluding generation winter capacity, of 4,165.2 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 11, DEOK LDA unforced internal capacity decreased 247.6 MW from 4,412.8 MW in the 2021/2022 BRA as a result of net generation capacity modifications (114.8 MW), net DR modifications (2.1 MW), and net EE modifications (59.0 MW), the EFORd effect due to higher sell offer EFORds (-422.2 MW), and the DR and EE effect due to a lower Load Management UCAP conversion factor (-1.3 MW). As shown in Table 13, total internal DEOK unforced winter capacity increased by 0.0 MW for November through April of the 2022/2023 Delivery Year.

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177 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.[178] Total internal DEOK LDA capacity was reduced by FRR commitments of 910.2 MW, resulting in DEOK LDA RPM capacity of 3,255.0 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 21.2 MW of DR and EE not offered and 0.0 MW of unoffered generation winter capacity resulted in available unforced capacity in DEOK LDA of 3,233.8 MW.[179] After accounting for these exceptions, all capacity resources in DEOK LDA were offered in the RPM Auction.

The DEOK LDA import limit was a binding constraint in the 2022/2023 BRA. Of the 2,117.7 MW cleared in DEOK LDA, 1,838.1 MW were cleared in the RTO before DEOK LDA became constrained. Once the constraint was binding, based on the 5,465.0 MW CETL value, only the incremental supply located in DEOK LDA was available to meet the incremental demand in the LDA. Of the incremental supply, 279.6 MW cleared, which resulted in a clearing price for Capacity Performance Resources of $71.69 per MW-day, as shown in Figure 7. The clearing price was determined by the intersection of the incremental supply and VRR curve.

As shown in Table 18, the 1,971.8 MW of cleared and uplift generation and DR for DEOK LDA and 5,465.0 MW CETL resulted in a net excess of 929.1 MW.

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178 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).

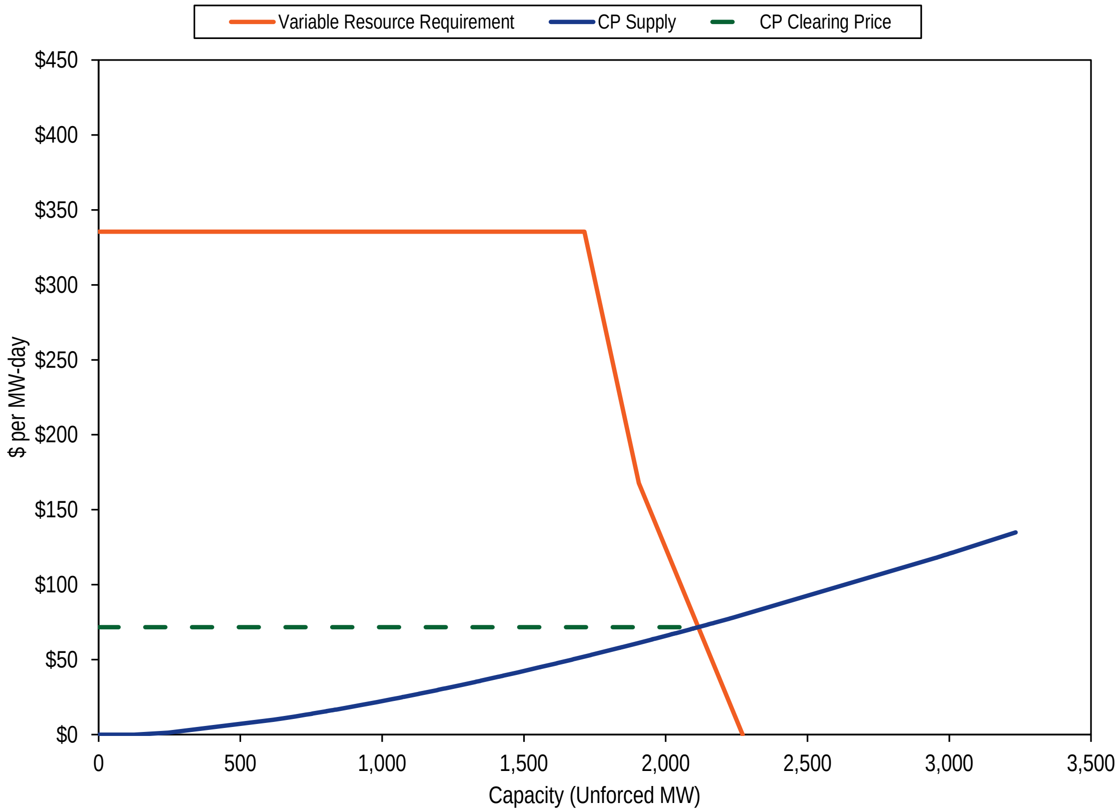
179 Unoffered DR and EE MW include PJM approved DR and EE plans that were not offered in the auction.

Table and Figure for DEOK LDA

Table 50 DEOK LDA offer statistics: 2022/2023 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	4,290.8	3,756.7		
DR capacity	238.6	259.1		
EE capacity	137.6	149.4		
Generation winter capacity	0.0	0.0		
Total internal DEOK LDA capacity	4,667.0	4,165.2		
FRR	(962.6)	(910.2)		
Imports	0.0	0.0		
RPM capacity	3,704.4	3,255.0		
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	(19.5)	(21.2)		
Available	3,684.9	3,233.8	100.0%	100.0%
Generation offered	3,331.7	2,850.3	90.4%	88.1%
DR offered	218.3	237.0	5.9%	7.3%
EE offered	134.9	146.5	3.7%	4.5%
Total offered	3,684.9	3,233.8	100.0%	100.0%
Unoffered Existing Generation Capacity Resources	0.0	0.0	0.0%	0.0%

Figure 7 DEOK LDA market supply/demand curves: 2022/2023 RPM Base Residual Auction[180]



180 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 2022/2023 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.

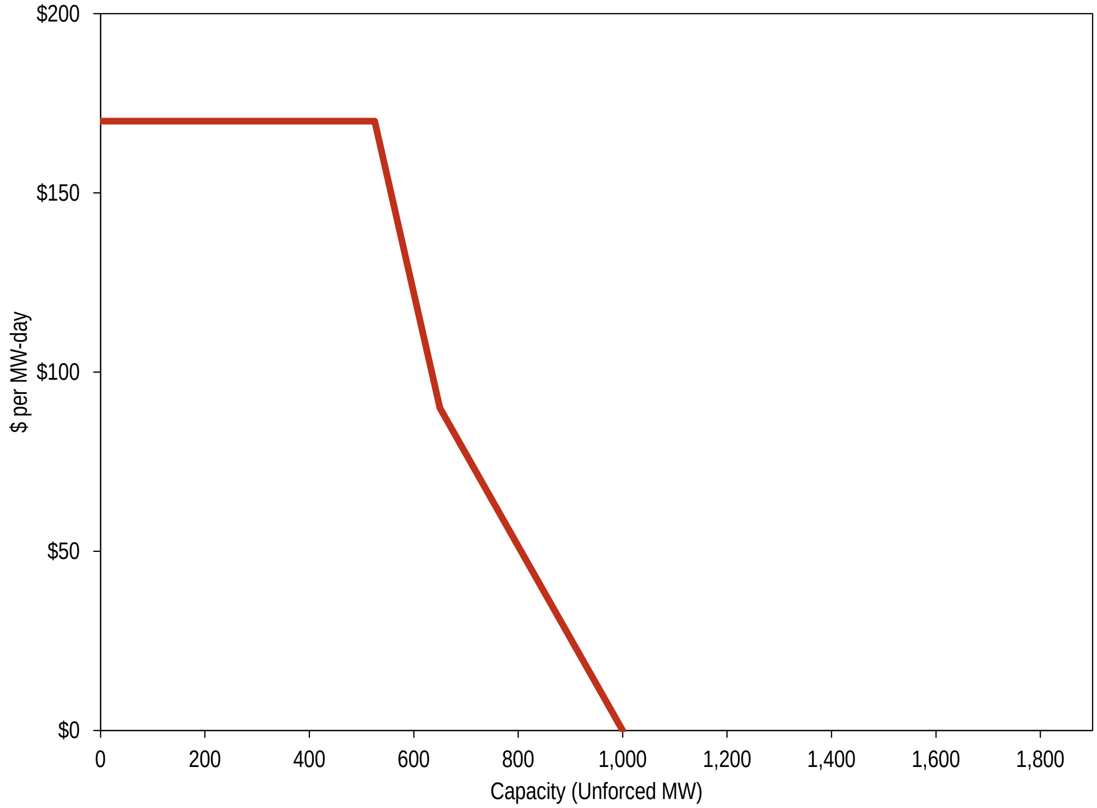
The MMU recommends improving the RPM solution method related to uplift payments. The MMU recommends changing the RPM solution method to explicitly incorporate the cost of uplift payments in the objective function.

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 8 and Figure 9 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

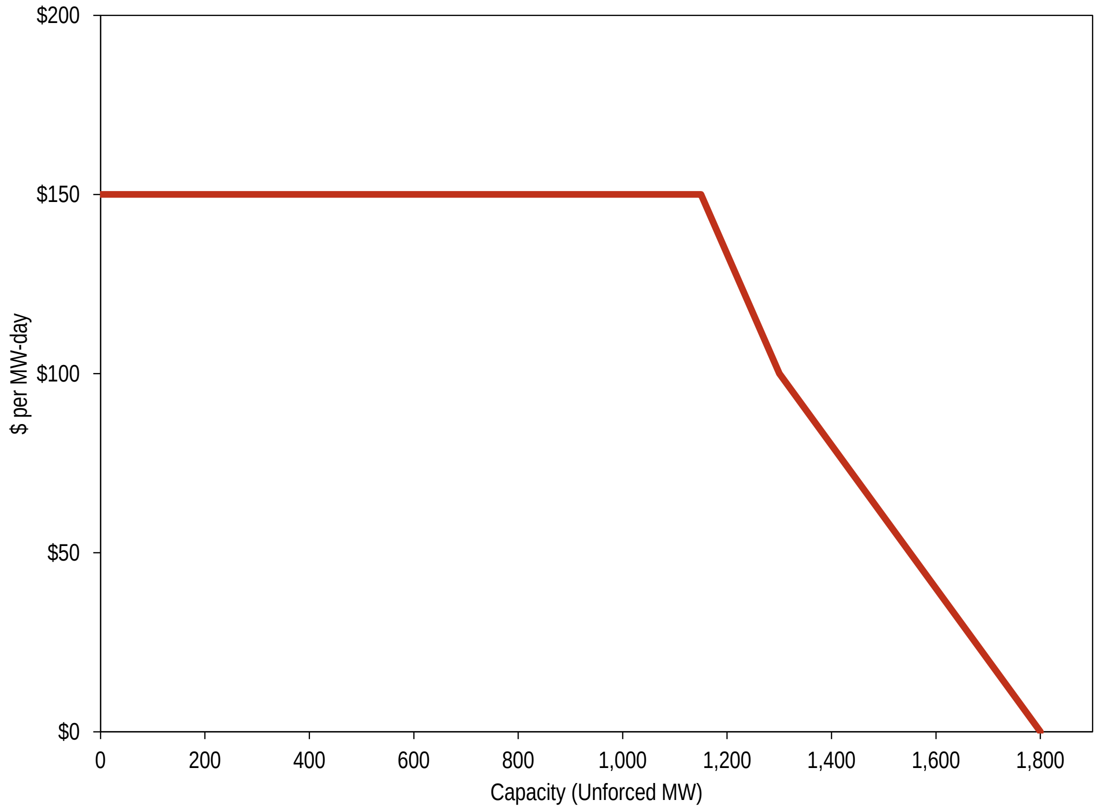


Figure 10 and Figure 11 illustrate the solution for the first scenario. Only 189.1 MW of the available 300 MW CETL is utilized. Therefore the CETL constraint is non-binding and out of merit offers are not needed to meet the child LDA's Variable Resource Requirement. The marginal clearing price for both the parent and child LDA is $120.00.

Figure 3 Optimal solution for scenario 1: child LDA

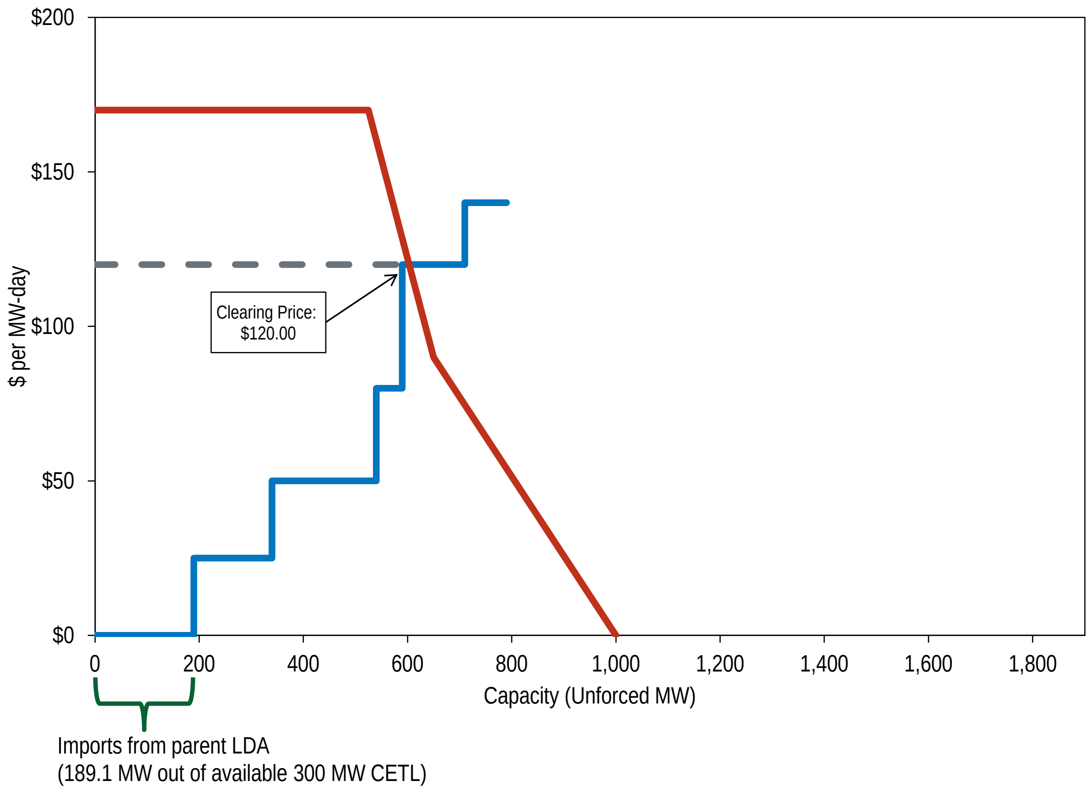


Figure 4 Optimal solution for scenario 1: Parent LDA

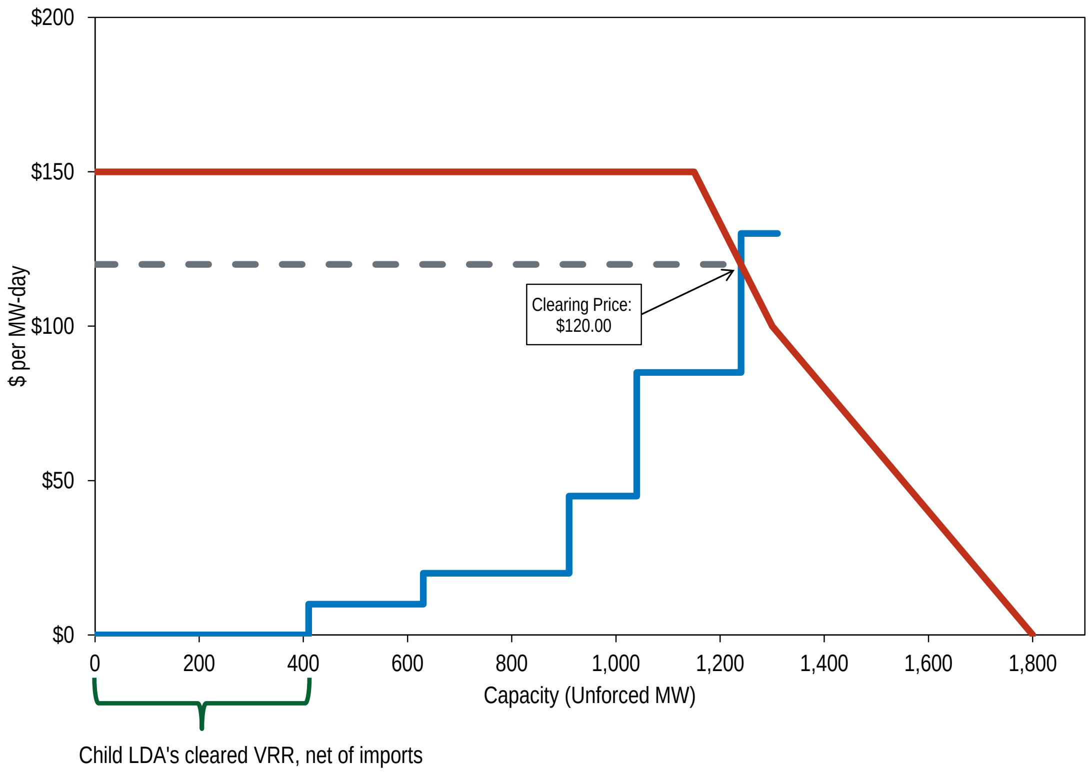


Figure 12 and Figure 13 illustrate the solution for the second scenario. The only difference between first and second scenarios is that the CETL is 150 MW in the second scenario compared to 300 MW in the first scenario. The solution shows that the entire 150 MW available is utilized by the child LDA 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

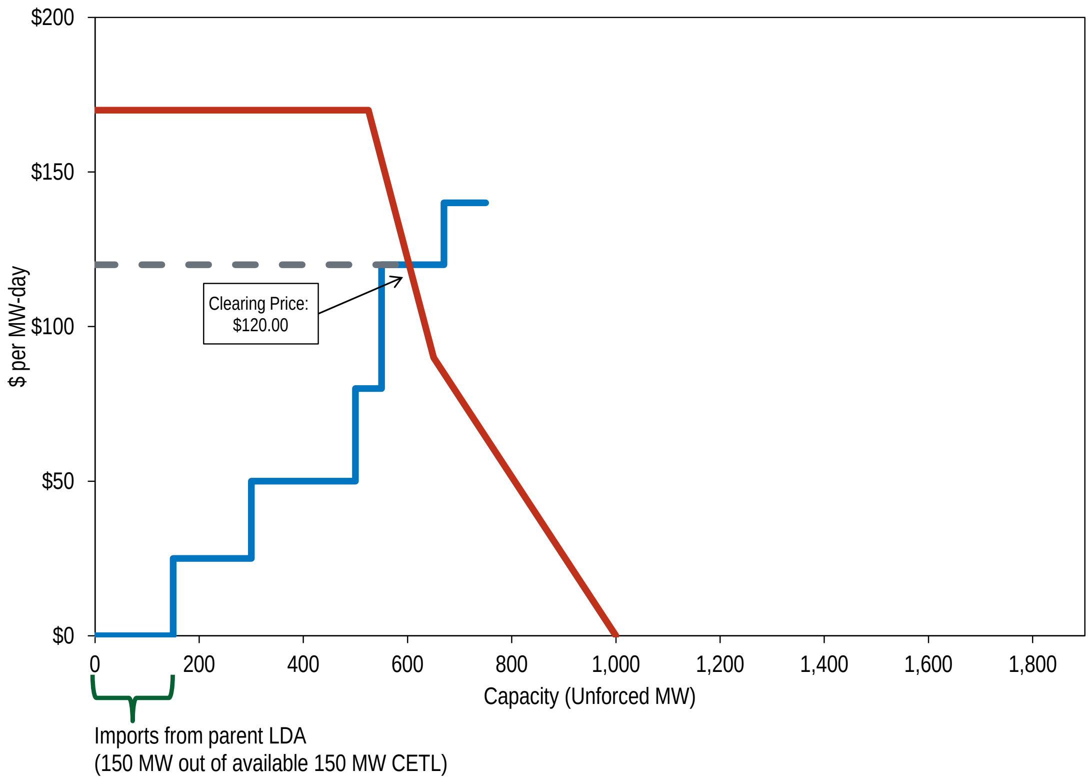


Figure 6 Optimal solution for scenario 2: Parent LDA