Monitoring Analytics

Analysis of the 2020/2021 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 fourteenth Reliability Pricing Model (RPM) Base Residual Auction (BRA) (for the 2020/2021 Delivery Year) which was held from May 10 to 16, 2017, 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.

This report addresses, explains and quantifies the basic market outcomes. This report also addresses and quantifies the impact on market outcomes of: the ComEd LDA and PSEG LDA Capacity Emergency Transfer Limits (CETL); the forecast peak load; Demand Resources (DR); the definition of capacity seasons; capacity imports; Price Responsive Demand (PRD); and the EE add back mechanism.[1]

Conclusions and Recommendations

The capacity market is, by design, always tight in the sense that total supply is generally only slightly larger than demand. 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. 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. Thus, the reliability goal is to have total supply equal to or slightly above the 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 is almost entirely inelastic because the market rules require loads to purchase their share of the system capacity requirement. The level of elasticity incorporated in the RPM demand curve, called the Variable Resource Requirement (VRR) 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.

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

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 would mean that market participants would not be able to rely on the competitiveness of the market outcomes. However, the market power rules are not perfect and, as a result, competitive outcomes require continued improvement of the rules and ongoing monitoring of market participant behavior and market performance.

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 a competitive offer was changed in the Capacity Performance rules that are now part of the PJM Capacity Market rules. For units that could profitably provide energy under the Capacity Performance design even without a capacity payment because their CP bonus payments exceed their net ACR, based on expected unit specific performance, expected balancing ratio and expected PAH, the competitive, profit maximizing offer is (net CONE times B), where B is the expected average balancing ratio. This is the default offer cap for such units.[2]

The MMU verified the reasonableness of cost data and calculated the derived offer caps based on submitted data; calculated unit net revenues; verified that CP offer caps for low ACR units did not exceed net CONE times B; verified CP offer caps for high ACR units; reviewed Minimum Offer Price Rule (MOPR) exception and exemption requests; reviewed offers for Planned Generation Capacity Resources; verified capacity exports; verified offers based on opportunity costs; reviewed requests for exceptions to the RPM must offer requirement; reviewed requests for exceptions to the Capacity Performance (CP) must offer requirement; verified the sell offer Equivalent Demand Forced Outage

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2 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).

Rates (EFORds); reviewed requests for alternate maximum EFORds; reviewed documentation for Intermittent Resources and Capacity Storage Resources to support CP eligibility; reviewed risk adders; verified clearing prices based on the demand (VRR) curves; and verified that the market structure tests were applied correctly.[3] All participants to whom the three pivotal supplier (TPS) test was applied (in the RTO, MAAC, EMAAC, ComEd, 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 defined offer cap, and the submitted sell offer, absent mitigation, would have resulted in a higher market clearing price.[4] [5] The offer caps are designed to reflect the marginal cost of capacity. Based on the data and this review, the MMU concludes that the results of the 2020/2021 RPM Base Residual Auction were competitive, with the caveat that there are issues with the seasonal capacity rules and the assumptions used for the net CONE times B offer cap which have significant consequences for market outcomes. The result of not applying market power mitigation rules to generation resources that did not, absent mitigation, increase the market clearing price, had no impact on the clearing prices in the auction but did affect seasonal make whole payments paid to seasonal offers. The result was an exercise of market power as a result of a failure of the rules. While the dollar magnitude of the impact was limited in this auction, the rules should be fixed to ensure that market power cannot be exercised in future auctions.

The Capacity Performance design addressed significant recommendations raised by the MMU in prior reports. These recommendations were included in the Capacity Performance design which will not be fully implemented until the June 1, 2020, start of the 2020/2021 Delivery Year. The MMU had recommended the elimination of the 2.5 percent demand adjustment (Short-Term Resource Procurement Target). The MMU had

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3 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.

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

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

recommended that the performance incentives in the Capacity Market design be strengthened. The MMU had recommended that generation capacity resources be paid on the basis of whether they produce energy when called upon during any of the hours defined as critical. The MMU had recommended that all capacity imports be required to be pseudo tied in order to ensure that imports are 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. 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 the elimination of the 2.5 percent demand adjustment (Short-Term Resource Procurement Target).

The 2.5 percent offset was implemented to permit DR to clear in Incremental Auctions. The 2.5 percent of demand was withheld in the BRA, and PJM attempted to procure that amount in the IAs for the relevant delivery year, net of any change in the forecast peak load. It was not added to counter persistent forecast errors. Forecast errors should be addressed directly and explicitly for all PJM forecasts. It is essential that PJM use the same forecasts for capacity markets and for transmission planning to ensure the long term consistency of RTEP and RPM. To effectively use a lower forecast for capacity in RPM by reducing demand by an arbitrary 2.5 percent resulted in biasing the overall market results in favor of transmission rather than generation solutions to reliability issues. PJM's approach to the forecast issue in the 2019/2020 BRA and 2020/2021 BRA, by eliminating the 2.5 percent offset and by including the impact of EE, is a step forward but PJM must continue to improve the sophistication of its forecast methods.

The establishment of a pseudo tie is one requirement for an external resource to be eligible to participate in the PJM Capacity Market. But pseudo ties still permit external balancing authorities to have control over the availability and dispatch of pseudo tied external capacity resources under some conditions. The external balancing authorities must decide whether the terms of pseudo tie agreements are consistent with their requirements. But when the reliability needs of external balancing authorities are not consistent with external units serving as complete substitutes for PJM internal capacity, pseudo ties are not adequate to permit the participation of external capacity resources in the PJM capacity market.

Pseudo ties do not establish deliverability to PJM load. External areas must perform deliverability analyses consistent with PJM criteria and external generation must also be deliverable to PJM load. Pseudo ties do not guarantee that a NERC tag will not be required. Pseudo ties are subject to NERC Tagging requirements unless the pseudo tie is included in regional congestion management procedures. Pseudo ties do not ensure that the associated firm flow entitlements (FFE) are assigned to the unit and to PJM. This could result in the inability to dispatch external capacity resources in the day-ahead market which, for example, limits flows on MISO transmission lines to PJM's FFEs. This could also result in the payment of additional congestion by PJM load to MISO resulting from real-time operations. FFEs should be assigned to PJM for external capacity resources.

The MMU recommends that all costs incurred as a result of a pseudo tied unit be borne by the unit itself and included as appropriate in unit offers in the capacity market.

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). 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.

The MMU has recognized that the pseudo tie requirement is not enough to ensure the external units are full substitutes for internal capacity resources. The MMU recommends that all capacity imports be required to be deliverable to PJM load 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.

CETL is a critical parameter that has significant impacts on capacity market outcomes. PJM needs to significantly improve the clarity and transparency of its CETL calculations. 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 when there are no capacity imports and can be no capacity imports (e.g. from the NYISO). That assumption has had a significant impact on suppressing capacity market prices. CETL should be based on the ability to import capacity only where capacity exists and where capacity has a must offer requirement. Any other assumption overstates the amount of capacity supply and suppresses market prices.

The MMU recommends using the lower of the cost or price-based offer to calculate energy costs in the calculation of net revenues which are an offset in the calculation of unit specific capacity resource offer caps. This recommendation was rejected by FERC.[6]

[6] See 155 FERC ¶ 61,281 (2016).

The FERC approved approach, used in the 2020/2021 BRA, effectively requires use of the higher of the cost or price-based offer except when the resource is mitigated in the energy market. The FERC approved approach requires use of the higher cost-based offer if 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, and requires the use of the cost-based offer when the resource is mitigated and the cost-based offer is lower than the price-based offer.[7] Under the FERC approach, when the price-based offer was less than the fuel cost plus environmental costs, the higher cost-based offer would be used and net revenues would be lower under the FERC approach than under the MMU approach. The FERC approach meant that capacity market offers that incorporated net revenues would have lower net revenues and would be greater than or equal to the offers calculated under the MMU approach. The implementation of the capacity performance capacity market design effectively eliminated the impact of unit net revenues on capacity market offers as a result of the net CONE times B offer cap which replaced the net ACR offer cap.

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 and enhanced. The requirement to be a physical resource should apply at the time of auctions and should also constitute a commitment to be physical in the relevant delivery year. The requirement to be a physical resource should be applied to all resource types, including planned generation, demand resources and imports.[8] [9] All DR should be on the demand side of the market rather than on the supply side.

The MMU recommends that the net revenue calculation used by PJM to calculate the net Cost of New Entry (CONE) VRR parameter reflect the actual flexibility of units in responding to price signals rather than using assumed fixed operating blocks that are not a result of actual unit limitations.[10] [11] The result of reflecting the actual flexibility is

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

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

9 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2016," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_06012007_to_06012016_20161227.pdf> (December 27, 2016).

10 See PJM Interconnection, L.L.C., Docket No. ER12-513-000 (December 1, 2011) ("Triennial Review").

higher net revenues, which affect the parameters of the RPM demand curve and market outcomes. 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.[12] The MMU recommends that the MOPR rule be extended to existing units in a manner comparable to the application of the MOPR rule to new units.[13] [14]

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.

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11 See the *2016 State of the Market Report for PJM*, Vol. 2, Section 5, Capacity.

12 *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).

13 See Comments of the Independent Market Monitor for PJM. Docket No. EL16-49-000. (April 11, 2016).

14 See IMM Proposal for the Capacity Construct/Public Policy Senior Task Force, <http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_CCPPSTF_Proposal_Summary_Revised_3_Redline_20171112.pdf> (November 12, 2017).

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.

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 PS-NORTH LDA can satisfy the reliability requirement of PS-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 PS-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 PS-NORTH'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 make whole payments.[15] The MMU recommends changing the RPM solution method to explicitly incorporate the cost of make whole payments in the objective function.

The MMU recommends that Energy Efficiency Resources not be included on the supply side of the capacity market, because PJM's load forecasts now account for future Energy Efficiency Resources, unlike the situation when EE was first added to the capacity market. However, the MMU recommends that the PJM load forecast method should be modified so that EE impacts immediately affect the forecast without the long lag times incorporated in the current forecast method. If EE is not included on the supply side, there is no reason to have an add back mechanism. If EE remains on the supply side, the implementation of the EE add back mechanism should be modified to ensure that market clearing prices are not affected.

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

The RPM rules require that offer caps are applied to all sell offers for Existing Generation Capacity Resources when the Capacity Market Seller did not pass the three pivotal supplier test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would have resulted in a higher market clearing price.[16] Under the seasonal capacity rules, the optimization considers the total cost of clearing a seasonal offer in combination with an offer for the opposite season, and this can result in clearing seasonal sell offers with prices greater than the clearing price and making seasonal make whole payments based on those high prices. The MMU recommends that the RPM market power mitigation rule be modified to apply offer caps in all cases when the three pivotal supplier test is failed and the sell offer is greater than the offer cap. This will ensure that market power does not result in an increase in make whole payments as occurred in the 2020/2021 BRA.

Results

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 equal to the reliability requirement. As shown in Table 13 and Table 14, the 163,399.0 MW of cleared and make whole generation and DR for the entire RTO, resulted in a reserve margin of 23.9 percent and a net excess of 9,043.7 MW over the reliability requirement of 154,355.3 MW.[17] [18] Inclusion of cleared EE Resources in the calculations on the supply side and as an add back on the demand side results in a calculated reserve margin of 23.3 percent and a net excess of 8,520.3 MW over the reliability requirement of 154,355.3 MW. In the 2020/2021 BRA, the reserve margin calculation including EE Resources is lower than the reserve margin calculation excluding EE, because the cleared MW of EE on the supply side was less than the EE add back MW on the demand side.

The decrease in the ComEd CETL of -1,096.0 MW, or 21.2 percent, from the 2019/2020 level to the 2020/2021 level had a significant impact on the auction results. Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2020/2021 RPM Base Residual Auction were $6,964,679,748. If the

16 OATT Attachment DD § 6.5.

17 The 23.9 percent reserve margin does not include EE on the supply side or the EE add back 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.

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

2019/2020 CETL value for ComEd had been used in the 2020/2021 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2020/2021 RPM Base Residual Auction would have been $6,879,241,720, a decrease of $85,438,029, or 1.2 percent, compared to the actual results. From another perspective, the use of the 2020/2021 CETL value for ComEd resulted in a 1.2 percent increase in RPM revenues for the 2020/2021 RPM Base Residual Auction compared to what RPM revenues would have been using the 2019/2020 CETL value for ComEd. (Scenario 1) Table 1 and Table 2 summarize the sensitivity analyses.

PJM introduced updates to the PJM RTEP in August 2017, and corrections to the CETL calculations, that would have had a significant impact on the 2020/2021 RPM Base Residual Auction had the updates been incorporated in the determination of CETL values for the 2020/2021 RPM Base Residual Auction. The updates to the planning process stem from the termination of the ConEd Wheel Agreement. The updates include changes to the PJM NYISO PAR flows. The corrections were that PJM will no longer assume non-firm import capacity is available when determining the CETL values for MAAC, EMAAC, PSEG, and PSEG North. It was incorrect to assume that external capacity resources were available to meet the demand for capacity in the PJM Capacity Market because external capacity resources are required to have firm transmission and, as a result of the absence of firm transmission in the NYISO tariff, no capacity resources have been or could be imported from NYISO. In clearing the PJM capacity market, the only relevant supply consists of capacity resources that meet the definition of capacity resources. The fact that external resources may be able to help PJM in an emergency, while potentially relevant from a planning perspective, is not relevant to defining the supply and demand of capacity resources in the PJM Capacity Market.

Table 27 shows the initial and final PJM CETL values for MAAC, EMAAC, PSEG, and PSEG North for the 2020/2021 BRA and the proposed CETL values. The proposed CETL values equal the PJM updated values. The proposed CETL value for MAAC is 3,118 MW, which is 1,100 MW lower than the value used in the 2020/2021 BRA. The proposed CETL value for EMAAC is 8,300, a 500 MW decrease from the CETL value used in the 2020/2021 BRA. The proposed CETL value for PSEG is 6,474 MW, a 1,527 MW decrease from the CETL value used in the 2020/2021 BRA. The proposed CETL value for PSEG North is 2,955 MW, a 1,309 MW decrease from the CETL value used in the 2020/2021 BRA.

PJM's updates and corrections should have been calculated prior to the BRA and implemented in the BRA. If PJM's updates and corrections had been implemented in the BRA, they would have had a significant impact. Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2020/2021 RPM Base Residual Auction were $6,964,679,748. If PJM had used the new assumptions related to PJM NYISO PAR flows and non-firm import capacity in the CETL studies for MAAC, EMAAC, PSEG, and PSEG North in the 2020/2021 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2020/2021 RPM Base Residual Auction would have been $7,195,144,017, an increase of $230,464,269, or 3.3 percent, compared to the actual results. From another perspective, PJM's use of the non-updated CETL values resulted in a 3.2 percent decrease in RPM revenues for the 2020/2021 RPM Base Residual Auction compared to what RPM revenues would have been had the updated modeling assumptions regarding PJM NYISO PAR flows and the availability of non-firm import capacity been used in the determination of the 2020/2021 CTEL values for MAAC, EMAAC, PSEG, and PSEG North. (Scenario 2)

The impacts of the CETL changes due to the updates to the PJM Regional Transmission Planning Process were particularly significant in PSEG. If PJM had used the new assumptions related to PJM NYISO PAR flows and nonfirm import capacity in the CETL studies for MAAC, EMAAC, PSEG, and PSEG North in the 2020/2021 RPM Base Residual Auction and everything else had remained the same, PSEG would have experienced a form of scarcity pricing in the BRA. All available annual supply and all available seasonal supply matched with feasible complementary seasonal supply in the PSEG LDA would have cleared and the clearing price would have been set by the intersection of the PSEG VRR curve and the vertical line extending upward from the last increment of cleared supply at $302.93 per MW-day. Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the PSEG LDA for the 2020/2021 RPM Base Residual Auction were $349,528,002. If PJM had used the new assumptions related to PJM NYISO PAR flows and nonfirm import capacity in the CETL studies for MAAC, EMAAC, PSEG, and PSEG North in the 2020/2021 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the PSEG LDA for the 2020/2021 RPM Base Residual Auction would have been $624,175,602, an increase of $274,647,600, or 78.6 percent, compared to the actual results. From another perspective, PJM's use of the non-updated CETL values resulted in a 44.0 percent decrease in RPM revenues for the PSEG LDA for the 2020/2021 RPM Base Residual Auction compared to what RPM revenues would have been had the updated modeling assumptions regarding PJM NYISO PAR flows and the availability of nonfirm import capacity been used in the determination of the 2020/2021 CTEL values for MAAC, EMAAC, PSEG, and PSEG North. (Scenario 2)

The accuracy of the peak load forecast has a significant impact on RPM Base Residual Auction results. An analysis of the RPM auctions for the 2013/2014 through 2017/2018 delivery years shows that the peak load forecast for the Third Incremental Auction has been on average 6.2 percent lower than the peak load forecast for the corresponding Base Residual Auction. If the peak load forecast for the 2020/2021 RPM Base Residual Auction had been 6.2 percent lower and everything else had remained the same, total RPM market revenues for the 2020/2021 RPM Base Residual Auction would have been $5,489,678,329, a decrease of $1,475,001,419, or 21.2 percent, compared to the actual results. From another perspective, using PJM's peak load forecast for the 2020/2021 Base

Residual Auction resulted in a 26.9 percent increase in RPM revenues for the 2020/2021 RPM Base Residual Auction compared to what revenues would have been using a load forecast that is 6.2 percent below the PJM peak load forecast. (Scenario 3)

The inclusion of sell offers for Demand Resources and Energy Efficiency resources had a significant impact on the auction results. Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2020/2021 RPM Base Residual Auction were $6,964,679,748. If there had been no offers for DR or EE in the 2020/2021 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2020/2021 RPM Base Residual Auction would have been $8,048,320,630, an increase of $1,083,640,882, or 15.6 percent, compared to the actual results. From another perspective, the inclusion of Demand Resources and Energy Efficiency resources resulted in a 13.5 percent reduction in RPM revenues for the 2020/2021 RPM Base Residual Auction compared to what RPM revenues would have been without any Demand Resources or Energy Efficiency resources. (Scenario 4)

The 2020/2021 RPM Base Residual Auction was the second BRA held using the EE add back mechanism. RPM rules allow Energy Efficiency Resources to participate on the supply side. An adjustment is made to the demand curve through the EE add back mechanism to avoid double counting, since EE for the delivery year is reflected in the revised load forecast model for the same delivery year. The EE add back mechanism had a significant impact on the auction results. Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2020/2021 RPM Base Residual Auction were $6,964,679,748. If there were no offers for EE and the EE add back MW were set to zero in the 2020/2021 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2020/2021 RPM Base Residual Auction would have been $6,673,183,027, a decrease of $291,496,721, or 4.2 percent, compared to the actual results. From another perspective, the inclusion of Energy Efficiency Resource offers and the EE add back MW, resulted in a 4.4 percent increase in RPM revenues for the 2020/2021 RPM Base Residual Auction compared to what RPM revenues would have been if energy efficiency projects were reflected in the demand and EE Resources did not participate on the supply side. (Scenario 5)

The inclusion of sell offers for Annual Demand Resources and Energy Efficiency resources had a significant impact on the auction results. Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2020/2021 RPM Base Residual Auction were $6,964,679,748. If there had been no offers for Annual DR or EE in the 2020/2021 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2020/2021 RPM Base Residual Auction would have been $7,937,273,776, an increase of $972,594,027, or 14.0 percent, compared to the actual results. From another perspective, the inclusion of Annual Demand Resources and Energy Efficiency resources resulted in a 12.3 percent reduction in RPM revenues for the 2020/2021 RPM Base Residual Auction compared to what RPM revenues would have been without any Annual Demand Resources or Energy Efficiency resources. (Scenario 6)

This is the best measure of the competitive impact of demand side products on the RPM market. The Annual DR product definition is the only one relatively close to consistent with being a capacity resource although the demand side product should be on the demand side rather than the supply side. Assuming that the DR offers meet appropriate measurement and verification standards and that the DR offers were made with the intention of providing physical resources, competition from the Annual DR product and Annual Energy Efficiency resources resulted in a 12.3 percent reduction in payments for capacity. This demonstrates that, with these strong assumptions, Annual DR together with Annual Energy Efficiency resources had a significant impact on market outcomes and resulted in the displacement of generation resources. Thus, even when the DR product is limited to the Annual DR product, DR has a significant and appropriate competitive impact on capacity market outcomes, if the stated assumptions are correct. The market design should be modified such that the demand side product is on the demand side rather than the supply side. If the current DR resources are legitimate, there is no reason to believe that the market impact of the demand side product would be significantly different if the demand side product were on the demand side of the market as it should be.

The level of DR products that buy out of their positions after the BRA suggests that the impact of DR on generation investment incentives needs to be carefully considered and that the rules governing the requirement to be a physical resource should be more clearly stated and enforced.[19] 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 capacity resources available in Incremental Auctions. This would suppress the price of capacity in the BRA compared to the competitive result because it permits the shifting of demand from the BRA to the Incremental Auctions, which is inconsistent with the must offer, must buy rules governing the BRA.

The inclusion of sell offers for Seasonal Demand Resources and Energy Efficiency resources had a small impact on the auction results. Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the

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[19] See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2016" <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_06012007_to_06012016_20161227.pdf> (December 27, 2016).

2020/2021 RPM Base Residual Auction were $6,964,679,748. If there had been no offers for Seasonal DR or EE in the 2020/2021 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2020/2021 RPM Base Residual Auction would have been $6,951,735,280, a decrease of $12,944,468, or 0.2 percent, compared to the actual results. From another perspective, the inclusion of Seasonal Demand Resources and Energy Efficiency resources resulted in a 0.2 percent increase in RPM revenues for the 2020/2021 RPM Base Residual Auction compared to what RPM revenues would have been without any Seasonal Demand Resources or Energy Efficiency resources. (Scenario 7)

The 2020/2021 RPM Base Residual Auction was the first BRA held using the Seasonal products for summer and winter capacity. The inclusion of seasonal offers had a limited impact on the auction results. Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2020/2021 RPM Base Residual Auction were $6,964,679,748. If there had been no offers for Seasonal products in the 2020/2021 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2020/2021 RPM Base Residual Auction would have been $6,993,615,290, an increase of $28,935,542, or 0.4 percent, compared to the actual results. From another perspective, the inclusion of Seasonal offers resulted in a 0.4 percent decrease in RPM revenues for the 2020/2021 RPM Base Residual Auction compared to what RPM revenues would have been without any Seasonal offers. (Scenario 8)

The inclusion of sell offers from Demand Resources, Energy Efficiency resources, and Seasonal resources had a significant impact on the auction results. Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2020/2021 RPM Base Residual Auction were $6,964,679,748. If there had been no offers from Demand Resources, Energy Efficiency resources, or Seasonal resources in the 2020/2021 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2020/2021 RPM Base Residual Auction would have been $8,134,983,164, an increase of $1,170,303,415, or 16.8 percent, compared to the actual results. From another perspective, the inclusion of Demand Response, Energy Efficiency, and Seasonal resources resulted in a 14.4 percent decrease in RPM revenues for the 2020/2021 RPM Base Residual Auction compared to what RPM revenues would have been without any Demand Resources, Energy Efficiency resources, or Seasonal resources. (Scenario 9)

The inclusion of winter resources had a limited impact on the auction results. Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2020/2021 RPM Base Residual Auction were $6,964,679,748. If the amount of winter offers had been reduced by 50 percent in the 2020/2021 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2020/2021 RPM Base Residual Auction would have been $6,970,014,319, an increase of $5,334,571, or 0.1 percent, compared to the actual results. From another perspective, the inclusion of all winter offers resulted in a 0.1 percent decrease in RPM revenues for the 2020/2021 RPM Base Residual Auction compared to what RPM revenues would have been if offers from winter resources had been reduced by 50 percent. (Scenario 10)

New RPM rules allow for the matching of complementary Seasonal products across LDAs. An offer for summer capacity in PSEG can 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 and the combined offer would receive the RTO clearing price. Matching seasonal offers across LDAs had a significant impact on the auction results. Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2020/2021 RPM Base Residual Auction were $6,964,679,748. If seasonal offers were not matched with complementary seasonal offers from other LDAs in the 2020/2021 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2020/2021 RPM Base Residual Auction would have been $6,993,516,300, an increase of $28,836,552, or 0.4 percent, compared to the actual results. From another perspective, allowing seasonal offers to be matched with complementary seasonal offers in other LDAs resulted in a 0.4 percent decrease in RPM revenues for the 2020/2021 RPM Base Residual Auction compared to what RPM revenues would have been if seasonal offers were not matched across LDAs. (Scenario 11)

The inclusion of capacity imports in the 2020/2021 RPM Base Residual Auction had a significant impact on the auction results. Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2020/2021 RPM Base Residual Auction were $6,964,679,748. If offers for external generation were reduced by 25 percent and everything else had remained the same, total RPM market revenues for the 2019/2020 RPM Base Residual Auction would have been $7,010,987,176, an increase of $46,307,427, or 0.7 percent, compared to the actual results. From another perspective, the impact of including all offers for external generation resources resulted in a 0.7 percent reduction in RPM revenues for the 2020/2021 RPM Base Residual Auction compared to what RPM revenues would have been if offers for external generation resources had been reduced by 25 percent. (Scenario 12, Scenario 13, Scenario 14)

If offers for external generation were reduced by 75 percent and everything else had remained the same, total RPM market revenues for the 2020/2021 RPM Base Residual Auction would have been $7,401,236,623, an increase of $436,556,875, or 6.3 percent, compared to the actual results. From another perspective, the impact of including all offers for external generation resources resulted in a 5.9 percent reduction in RPM revenues for the 2020/2021 RPM Base Residual Auction compared to what RPM revenues would have been if offers for external generation resources had been reduced by 75 percent. (Scenario 12, Scenario 13, Scenario 14)

The inclusion of sell offers from Demand Resources, Energy Efficiency resources, Seasonal resources, and imports had a significant combined impact on the auction results. Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2020/2021 RPM Base Residual Auction were $6,964,679,748. If there had been no offers from Demand Resources, Energy Efficiency resources, or Seasonal resources, and imports had been reduced by 75 percent in the 2020/2021 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2020/2021 RPM Base Residual Auction would have been $9,127,165,743, an increase of $2,162,485,995, or 31.0 percent, compared to the actual results. From another perspective, the inclusion of Demand Response, Energy Efficiency, and seasonal resources and including all offers for external generation resources resulted in a 23.7 percent decrease in RPM revenues for the 2020/2021 RPM Base Residual Auction compared to what RPM revenues would have been without any Demand Resources, Energy Efficiency resources, or seasonal resources and offers for external generation resource reduced by 75 percent. (Scenario 15)

Under the EE add back MW rules, the demand curve was shifted by an amount greater than the quantity of cleared EE, so the clearing price was increased as a result of the implementation of the EE add back mechanism. If adjustments to the EE add back MW had been made such that for each LDA the EE cleared MW were equal to the EE add back MW, and everything else had remained the same, total RPM market revenues for the 2020/2021 RPM Base Residual Auction would have been $6,802,281,900, a decrease of $162,397,848, or 2.3 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 add back MW, resulted in a 2.4 percent increase in RPM revenues for the 2020/2021 RPM Base Residual Auction compared to what RPM revenues would have been if the EE add back MW were equal to the EE cleared MW for each LDA. (Scenario 16)

The 2020/2021 RPM Base Residual Auction was the first BRA that included submissions for Price Responsive Demand (PRD). The inclusion of PRD had a significant impact on the auction results. Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2020/2021 RPM Base Residual Auction were $6,964,679,748. If there had been no submissions from PRD providers in the 2020/2021 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2020/2021 RPM Base Residual Auction would have been $7,103,194,078, an increase of $138,514,329, or 2.0 percent, compared to the actual results. From another perspective, the inclusion of PRD resulted in a 2.0 percent reduction in RPM revenues for the 2020/2021 RPM Base Residual Auction compared to what RPM revenues would have been without any PRD. (Scenario 17)

PJM modeled PRD as offers from a supply side resource rather than incorporating the PRD offers into the VRR curve.

Tables for Results Section

Table 1 Scenario summary of RPM revenue: 2020/2021 RPM Base Residual Auction

			Scenario Impact	
Scenario	Scenario Description	RPM Revenue ($ per Delivery Year)	RPM Revenue ($ per Delivery Year)	Percent
0	Actual Results	$6,964,679,748	NA	NA
1	Decrease in the ComEd CETL	$6,879,241,720	$85,438,029	1.2%
2	Impact of CETL Assumptions	$7,195,144,017	($230,464,269)	(3.2%)
3	Impact of Load Forecast	$5,489,678,329	$1,475,001,419	26.9%
4	Inclusion of DR/EE Offers	$8,048,320,630	($1,083,640,882)	(13.5%)
5	Inclusion of EE Offers and EE Add Back	$6,673,183,027	$291,496,721	4.4%
6	Inclusion of Annual DR/EE Offers	$7,937,273,776	($972,594,027)	(12.3%)
7	Inclusion of Seasonal DR/EE Offers	$6,951,735,280	$12,944,468	0.2%
8	Inclusion of Seasonal Products	$6,993,615,290	($28,935,542)	(0.4%)
9	Inclusion of DR/EE and Seasonal Resources	$8,134,983,164	($1,170,303,415)	(14.4%)
10	Inclusion of 50 Percent of Offers from Winter Resources	$6,970,014,319	($5,334,571)	(0.1%)
11	Inclusion of Seasonal Matching Across LDAs	$6,993,516,300	($28,836,552)	(0.4%)
12	Inclusion of 75 Percent of Offers for External Generation	$7,010,987,176	($46,307,427)	(0.7%)
13	Inclusion of 50 Percent of Offers for External Generation	$7,183,521,438	($218,841,690)	(3.0%)
14	Inclusion of 25 Percent of Offers for External Generation	$7,401,236,623	($436,556,875)	(5.9%)
15	Inclusion of DR/EE, Seasonal Capacity, and 25 Percent of Offers from External Generation	$9,127,165,743	($2,162,485,995)	(23.7%)
16	Impact of Adjusting the VRR Curve by EE Add Back Amount that Differs from Cleared EE	$6,802,281,900	$162,397,848	2.4%
17	Inclusion of PRD	$7,103,194,078	($138,514,329)	(2.0%)

Table 2 Scenario summary of cleared UCAP: 2020/2021 RPM Base Residual Auction

			Scenario Impact	
Scenario	Scenario Description	Cleared UCAP (MW)	Cleared UCAP (MW)	Percent
0	Actual Results	165,109.2	NA	NA
1	Decrease in the ComEd CETL	164,954.6	154.6	0.1%
2	Impact of CETL Assumptions	165,130.3	(21.1)	0.0%
3	Impact of Load Forecast	154,571.1	10,538.1	6.8%
4	Inclusion of DR/EE Offers	161,737.1	3,372.1	2.1%
5	Inclusion of EE Offers and EE Add Back	162,748.5	2,360.7	1.5%
6	Inclusion of Annual DR/EE Offers	161,997.5	3,111.7	1.9%
7	Inclusion of Seasonal DR/EE Offers	164,928.5	180.7	0.1%
8	Inclusion of Seasonal Products	164,875.4	233.8	0.1%
9	Inclusion of DR/EE and Seasonal Resources	161,689.2	3,420.0	2.1%
10	Inclusion of 50 Percent of Offers from Winter Resources	164,763.3	345.9	0.2%
11	Inclusion of Seasonal Matching Across LDAs	165,122.9	(13.7)	(0.0%)
12	Inclusion of 75 Percent of Offers for External Generation	164,925.2	184.0	0.1%
13	Inclusion of 50 Percent of Offers for External Generation	164,724.4	384.8	0.2%
14	Inclusion of 25 Percent of Offers for External Generation	164,552.6	556.6	0.3%
15	Inclusion of DR/EE, Seasonal Capacity, and 25 Percent of Offers from External Generation	160,748.5	4,360.7	2.7%
16	Impact of Adjusting the VRR Curve by EE Add Back Amount that Differs from Cleared EE	164,429.0	680.2	0.4%
17	Inclusion of PRD	165,701.6	(592.4)	(0.4%)

Clearing Prices

Table 3 shows the clearing prices for Capacity Performance Resources in the 2020/2021 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 Hours 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, except DPL. The ratio of clearing price to net CONE times B was less than 55 percent for 11 of the 20 zones and exceeded 85 percent for only four zones.

Table 3 Clearing prices and net CONE times B: 2020/2021 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	$187.82	$280.33	0.79	$220.06	($32.24)	85.3%
AEP	$76.55	$262.03	0.79	$205.69	($129.14)	37.2%
AP	$76.53	$230.15	0.79	$180.67	($104.14)	42.4%
ATSI	$76.53	$243.96	0.79	$191.51	($114.98)	40.0%
BGE	$85.98	$166.58	0.79	$130.77	($44.79)	65.7%
ComEd	$188.13	$308.07	0.79	$241.83	($53.70)	77.8%
DAY	$76.53	$255.14	0.79	$200.28	($123.75)	38.2%
DEOK	$129.84	$263.85	0.79	$207.12	($77.28)	62.7%
DLCO	$76.53	$266.96	0.79	$209.56	($133.03)	36.5%
DPL	$187.36	$238.17	0.79	$186.96	$0.40	100.2%
Dominion	$76.53	$277.23	0.79	$217.63	($141.10)	35.2%
EKPC	$76.53	$276.49	0.79	$217.04	($140.51)	35.3%
External	$76.53	$273.64	0.79	$214.81	($138.28)	35.6%
JCPL	$187.80	$244.73	0.79	$192.11	($4.31)	97.8%
Met-Ed	$86.04	$248.45	0.79	$195.03	($108.99)	44.1%
PECO	$187.84	$254.44	0.79	$199.74	($11.90)	94.0%
PENELEC	$86.08	$130.40	0.79	$102.36	($16.28)	84.1%
PPL	$86.04	$249.71	0.79	$196.02	($109.98)	43.9%
PSEG	$187.84	$286.69	0.79	$225.05	($37.21)	83.5%
Pepco	$86.01	$211.60	0.79	$166.11	($80.10)	51.8%
RECO	$185.49	$282.30	0.79	$221.61	($36.12)	83.7%

Market Changes

RPM Market Design Changes

Seasonal Capacity

Effective for the 2020/2021 and subsequent Delivery Years, the RPM market design incorporated seasonal capacity resources.[20] [21]

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20 158 FERC ¶ 62,220.

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

Summer period capacity performance resources may include summer period demand resources, summer period 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 measurable greater than its average expected energy output during winter peak hour periods.

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.

Related to the winter period capacity resources, generation owners of intermittent resources and environmentally limited resources can request winter capacity interconnection rights (CIRs). If the intermittent resource or environmentally limit resource is deemed deliverable by PJM for 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. This additional available 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. This additional capacity in winter is available not because the resources with CIRs cannot perform to their summer capability in winter; it is available because they are not needed to perform at their summer capability in the winter due to lower peak loads.

PJM’s practice of giving away winter CIRs that exist because of other resources that paid for necessary network upgrades creates a cross subsidization of interconnection costs. The additional capacity revenues that the winter seasonal resources receive based on winter capacity commitments that require use of the system capability paid for by other resources, increases the cross subsidization even further. If PJM were to retain the seasonal capacity markets construct, the MMU recommends that PJM create a market mechanism to value and efficiently allocate CIRs.

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 modeled in the smallest common LDA. While commercial aggregation rules within the same LDA were effective with the 2018/2019 delivery year with the implementation of the capacity performance rules, the seasonal capacity rules allow aggregation across LDAs and also allow capacity market sellers to offer standalone summer or winter resources and allow the auction clearing optimization to match and clear equal quantities of summer and winter resources.

The summer period capacity resources and winter period capacity resources located within 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 did not clear are moved up to the immediate parent LDA to be matched with the complementary seasonal resources located within the parent LDA. The matched seasonal offers located in different LDAs are cleared to satisfy the resource requirement of the lowest common parent LDA. However, under the PJM rules, seasonal resources are required to deliver during the performance assessment hours in the LDA where they are physically located, even though they are not cleared to satisfy the reliability requirement of that LDA. Moreover the seasonal matching rules are likely to increase the make whole payments because the seasonal resources offered higher than the clearing price could clear the auction when paired with complementary seasonal resources from other LDAs.

Price Responsive Demand (PRD)

Although price responsive demand was implemented in the RPM market rules effective May 15, 2012, the 2020/2021 BRA was the first RPM auction in which price responsive demand participated.[22] The major differences between DR and PRD include the less stringent measurement and verification requirements for PRD and the ability for PRD to receive PRD credits for the entire delivery year as compared to a summer period DR receiving auction credits for part of the delivery year.

Energy Efficiency Resource Rules

Prior to the 2019/2020 Base Residual Auction, EE resources were 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 2020/2021 Base Residual Auction was the second BRA for which EE was reflected in the revised load forecast model without a lag.[23] While it would have been logical to eliminate EE from the supply side as a result, an administrative add back mechanism was implemented instead. Effective December 17, 2015, an EE add back mechanism and related changes were implemented to accommodate EE Resource participation on the supply side.[24]

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22 137 FERC ¶ 61,204.

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

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

The mechanics of the EE add back mechanism are complex and do not appropriately adjust for the level of cleared EE resources. For each BRA, the reliability requirement of the RTO and each LDA is increased by the UCAP value of all EE Resources with accepted Measurement and Verification Plans for the auction. This increase is the EE add back amount. For the 2020/2021 BRA, this meant that the RTO VRR curve was shifted to the right by 3,092.9 MW. If the initial results of the BRA solution yield a ratio of EE add back MW to cleared EE MW which exceeds a predetermined threshold ratio, the EE add back MW are set equal to the cleared EE MW from the initial solution times 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 2020/2021 BRA, the ratio in the initial solution of 3,092.9/1,710.2=1.80850193 did exceed the applicable threshold ratio of 1.422519856. The logic of the threshold is not clear and is not consistent with an appropriate clearing of the Base Residual Auction.

Capacity Performance

Capacity Products and Resource Constraints

Effective for the 2018/2019 and subsequent Delivery Years, the Extended Summer and Limited DR products are eliminated. For a transition period during the 2018/2019 and 2019/2020 Delivery Years, PJM procured two product types, Capacity Performance and Base Capacity. Effective for the 2018/2019 and the 2019/2020 Delivery Years, a Base Capacity Demand Resource Constraint and a Base Capacity Resource Constraint, replacing the Sub-Annual Resource Constraint and Limited Resource Constraint, were established for each modeled LDA. These maximum quantities were set for reliability purpose to limit the quantity procured of the inferior products, including Base Capacity Generation Resources, Base Capacity Demand Resources, and Base Capacity Energy Efficiency Resources. Effective with the 2020/2021 Delivery Year, PJM procures a single capacity product, Capacity Performance. CP Resources are expected to be available and capable of providing energy and reserves when needed at any time during the Delivery Year.[25]

Short-Term Resource Procurement Target

Effective for the 2018/2019 and subsequent Delivery Years, the Short Term Resource Procurement Target was eliminated. Under the prior rules, application of the Short-Term Resource Procurement Target meant that 2.5 percent of the reliability requirement was removed from the demand curve (VRR curve).

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25 "PJM Manual 18: PJM Capacity Market," Rev.37 (April 27, 2017) at 9.

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.[26]

Offer Caps

Effective for the 2018/2019 and subsequent delivery years, the default offer cap for Capacity Performance Resources is the applicable zonal net Cost of New Entry (CONE) times (B), where B is the average of the Balancing Ratios (B) during the Performance Assessment Hours in the three consecutive calendar years that precede the Base Residual Auction for such delivery year.

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 available only for Capacity Performance Resources. AFAE is defined to include expenses related to fuel availability and delivery. CPQR is available for Capacity Performance Resources and, for the 2018/2019 and 2019/2020 Delivery Years, Base Capacity Resources. CPQR is defined to be the quantifiable and reasonably supported cost of mitigating the risks of nonperformance that are assumed by Capacity Performance Resources when they submit an offer.

Coupled Offers

Effective for the 2018/2019 and 2019/2020 Delivery Years, Capacity Market Sellers may submit coupled offers for CP and Base Capacity for any resource that can qualify as a CP Resource. Prior to the 2018/2019 Delivery Year, the coupling option was available to only DR and EE Resources.

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

Effective for the 2018/2019 through 2019/2020 Delivery Years, submission of a coupled offer is required for a Capacity Performance Resource Sell Offer that exceeds the applicable net CONE times B.

UCAP Value of DR and EE

Prior to the 2018/2019 Delivery Year, the UCAP value of DR and EE was 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 DR and EE is no longer discounted by the DR Factor.

Variable Resource Requirement Curve Shape and Gross Cost of New Entry (CONE) Values

Effective for the 2018/2019 and subsequent Delivery Years, the VRR curve shape and the Gross Cost of New Entry (CONE) values were revised as part of the triennial review. Between review periods, the gross CONE values for delivery years subsequent to 2015/2016 are determined by escalating the base values using the most recent twelve month change in the Handy-Whitman Index.

External Generation Resources

For the 2017/2018 through the 2019/2020 delivery year, Capacity Import Limits (CILs) were established for each of the five external source zones and the overall PJM region to account for the risk that external generation resources may not be able to deliver energy during the relevant delivery year due to the curtailment of firm transmission by third parties.[27] Capacity Market Sellers may request an exception to the CIL for an external generation resource by committing that the resource will be pseudo tied prior to the start of the relevant delivery year, by demonstrating that it has long-term firm transmission service confirmed on the complete transmission path from the resource to PJM, and by agreeing to be subject to the same RPM must offer requirement as internal PJM generation resources.

An external generation resource offering as a CP resource must obtain an exception to the CIL, which means that effective with the 2020/2021 delivery year, CILs are no longer defined as an RPM parameter. One of the most important requirements for offering a CP capacity import is that it must be pseudo tied. This is a new requirement and consistent with an MMU recommendation. 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.

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[27] 147 FERC ¶ 61,060 (2014).

The MMU has recognized that the pseudo tie requirement is not enough to ensure the external units are full substitutes for internal capacity resources.

RPM Must Offer Requirement and Market Power Mitigation

The 2020/2021 RPM Base Residual Auction was the seventh BRA conducted under the revised RPM rules effective January 31, 2011, related to the RPM must-offer requirement and market power mitigation.[28] These changes included clarifying the applicability of the must-offer requirement and the circumstances under which exemptions from the RPM must offer requirement would be allowed, 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 mitigation, treating a proposed increase in the capability of a Generation Capacity Resource in exactly the same way as a Planned Generation Capacity Resource for purposes of market power mitigation.

The 2020/2021 RPM Base Residual Auction was the fifth BRA conducted under the process related PJM Tariff revisions.[29] These revisions included defining additional deadlines and accelerating deadlines in advance of an auction related to exception processes for market seller offer caps, alternate maximum EFORds, MOPR, and the RPM must offer requirement.

Effective October 15, 2013, new and revised deadlines for requesting an exception to the RPM must offer requirement due to planned retirement were implemented.[30] The rationale for the earlier deadline is to allow new entrants adequate time to respond and enter the PJM generation interconnection queue in response to a planned retirement. Previously, the deadline for requesting an exception to the RPM must offer requirement based on the reason of retirement was 120 days prior to the auction. For the 2017/2018 BRA, a transition mechanism applied under which the deadline for requesting an exception to the RPM must offer requirement due to planned retirement was November 1, 2013. For all Base Residual Auctions for delivery years subsequent to 2017/2018, the deadline is September 1 prior to the auction. For the 2019/2020 BRA, a waiver to the deadline was granted, setting the deadline at October 1, 2015, because Capacity Market Sellers would need information on the results of the CP Transition Incremental Auctions

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28 134 FERC ¶ 61,065 (2011).

29 Letter Order in FERC Docket No. ER13-149-000 (November 28, 2012).

30 145 FERC ¶ 61,035 (2013).

posted on August 31, 2015, and September 9, 2015, in order to make an informed decision on retiring a resource.[31]

Effective with the 2017/2018 Delivery Year, external resources which request and are granted exceptions to the CIL are treated as existing for purposes of the RPM must offer requirement for the relevant and subsequent delivery years.

MOPR

There have been two changes to the RPM Minimum Offer Price Rule (MOPR) effective for recent auctions.

Effective April 12, 2011, the RPM Minimum Offer Price Rule (MOPR) was changed.[32] The changes to the MOPR included updating the calculation of the net Cost of New Entry (CONE) for combined cycle (CC) and combustion turbine (CT) plants, increasing the threshold value used in the screen to 90 percent for CC and CT plants, eliminating the net short requirement as a prerequisite for applying the MOPR, eliminating the impact screen, revising the process for reviewing proposed exceptions to the defined minimum sell offer price, and clarifying which resources are subject to the MOPR along with the duration of mitigation.

The 2019/2020 RPM Base Residual Auction was the sixth BRA conducted under the revised MOPR and the third conducted under the subsequent FERC orders related to the MOPR, including clarification on the duration of mitigation, which resources are subject to MOPR, and the MOPR review process.[33]

Effective May 3, 2013, the RPM Minimum Offer Price Rule (MOPR) was changed again as a result of a settlement among some parties that was approved by FERC.[34] The changes to the MOPR included establishing Competitive Entry and Self Supply Exemptions while also retaining the unit specific exemption process for those resources that do not qualify for the Competitive Entry or Self Supply Exemptions; changing the applicability of MOPR to include only combustion turbine, combined cycle, integrated gasification combined cycle (IGCC) technologies while excluding units primarily fueled

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[31] 152 FERC ¶ 61,151 (2015).

[32] 135 FERC ¶ 61,022 (2011).

[33] 135 FERC ¶ 61,022 (2011), *order on reh'g*, 137 FERC ¶ 61,145 (2011), *order on compliance*, 139 FERC ¶ 61,011, *order on compliance*, 140 FERC ¶ 61,123.

[34] 143 FERC ¶ 61,090 (2013).

with landfill gas or cogeneration units which are certified or self-certified as Qualifying Facilities (QFs); changing the applicability to increases in installed capacity of 20.0 MW or more combined for all units at a single point of interconnection to the Transmission System; changing the applicability to include the full capability of repowering of plants based on combustion turbine, combined cycle, IGCC technology; increasing the screen from 90 percent to 100 percent of the applicable net CONE values; and broadening the region subject to MOPR to the entire RTO from constrained LDAs only.

ACR

The default Avoidable Cost Rate (ACR) escalation method which had been recommended by the MMU was approved and became effective on February 5, 2013, for the 2016/2017 and subsequent Delivery Years.[35] [36] [37]

The FERC Order also approved updates to the base default ACR values and consolidation of the ACR technology classifications, which were effective for the 2017/2018 and subsequent Delivery Years.

Effective with the 2020/2021 Delivery Year, the default ACR based offer caps are not an offer cap option.

Demand Resource Rules

Effective January 31, 2013, a third test for determining the Limited DR Reliability Target was implemented by PJM with the goal of limiting the probability of requiring an interruption of longer than six hours, which is the maximum duration of an interruption for a Limited DR product.[38]

Effective for the 2014/2015 through the 2016/2017 Delivery Years, the RPM market design incorporated Annual and Extended Summer DR product types, in addition to the

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35 For more details on the default ACR calculation issue, see "Analysis of the 2013/2014 RPM Base Residual Auction Revised and Updated," pp. 6-9 <http://www.monitoringanalytics.com/reports/Reports/2010/Analysis_of_2013_2014_RPM_Base_Residual_Auction_20090920.pdf> (September 20, 2010).

36 PJM Interconnection, L.L.C., Docket No. ER13-529-000 (December 7, 2012) at 19.

37 142 FERC ¶ 61,092 (2013).

38 143 FERC ¶ 61,076 (2013).

previously established Limited DR product type.[39] Each DR product type is subject to a defined period of availability, a maximum number of interruptions, and a maximum duration of interruptions. The RPM rule changes related to DR product types also included the establishment of a maximum level of Limited DR and a maximum level of Extended Summer DR cleared in the auction, which were defined as a Minimum Annual Resource Requirement and a Minimum Extended Summer Resource Requirement for the PJM region as a whole and LDAs for which a separate VRR curve was established.[40] Annual Resources include generation resources, Annual DR, and EE.

The Minimum Resource Requirements were targets established by PJM to ensure that a sufficient amount of Annual Resources were procured in order to address reliability concerns with the Extended Summer and Limited DR products and to ensure that a sufficient amount of Annual Resources and Extended Summer Resources were procured in order to address reliability concerns with the Limited DR product. The reliability risk associated with relying on either the Extended Summer or Limited DR products results from the fact that reliability must be maintained in all 8,760 hours per year while these resources were required to respond for only a limited number of hours when needed for reliability. The Minimum Annual Resource Requirement is the minimum amount of capacity that PJM would seek to procure from Annual Resources in order to maintain reliability based on a PJM analysis of the probability of needing Limited DR resources.[41] The Minimum Extended Summer Resource Requirement is the minimum amount of capacity that PJM would seek to procure from Annual Resources and Extended Summer DR. In other words, there is a maximum level of Limited DR and a maximum level of Extended Summer DR that PJM would purchase to meet reliability requirements, because additional purchases of these products was not consistent with reliability based on a PJM analysis of the probability of needing Limited DR resources when they were not available. The maximum level of Limited and Extended Summer DR was the difference between the minimum level of Annual Resources and the VRR curve.

As part of the definition of the new DR products effective with the 2014/2015 Delivery Year, coupled DR sell offers were defined. Coupled DR sell offers were linked sell offers for a Demand Resource that was able to provide more than one of the three DR product types. For example, a DR offer based on a single facility could be offered as Annual,

39 134 FERC ¶ 61,066 (2011).

40 The LDAs for which Minimum Resource Requirements are established was subsequently revised. See 135 FERC ¶ 61,102 (2011).

41 *See* PJM filing initiating FERC Docket No. ER13-486-000 (November 30, 2012).

Extended Summer and Limited simultaneously in a coupled offer. Only Demand Resources of different product types could be coupled, and the Capacity Market Seller must have specified a sell offer price of at least $0.01 per MW-day more for the less limited DR product type within a coupled segment group.

PJM's auction clearing mechanism resulted in a higher price for Annual Resources if the MW of Annual Resources that would otherwise clear the auction, including all resources, were less than the Minimum Annual Resource Requirement that PJM requires for reliability. In that case the auction clearing mechanism selected Annual Resources that were more expensive than the clearing price that would have otherwise resulted in order to procure the defined Minimum Annual Resource Requirement. PJM's auction clearing mechanism also resulted in a higher price for Extended Summer Resources if the MW of Extended Summer Resources that would have otherwise cleared the auction were less than the Minimum Extended Summer Resource Requirement that PJM required for reliability. In that case the auction clearing mechanism selected Extended Summer Resources that were more expensive than the clearing price that would otherwise have resulted in order to procure the defined Minimum Extended Summer Resource Requirement.

This result is also described as procuring the Annual or Extended Summer Resources out of merit order because the minimum resource requirements are binding constraints. In cases where one or both of the minimum resource requirements bind, resources selected to meet the minimum requirements received a price adder to the system marginal price, in addition to any locational price adders needed to resolve locational constraints.

Effective January 31, 2012, the 2.5 percent holdback was not subtracted from the Minimum Annual and Extended Summer Resource Requirements.[42] The first auction affected was the 2015/2016 BRA. The prior rule required that the Short-Term Resource Procurement Target, or 2.5 percent holdback, be subtracted from all product types including Annual, Extended Summer and Limited DR. Under the old rule, in the case where either the Minimum Annual Resource Requirement or Minimum Extended Summer Resource Requirement were binding, the maximum amount of Limited DR would be procured in the Base Residual Auction, leaving none to be procured in Incremental Auctions for the relevant delivery year. Under the new rule, the entire 2.5 percent was subtracted from the amount of Limited DR procured in the BRA, assuming either the Minimum Annual Resource Requirement or Minimum Extended Summer Resource Requirement is binding. For example in the 2015/2016 BRA, applying the

43 146 FERC ¶ 61,052 (2014).

Short-Term Resource Procurement Target reduced the amount of Limited DR procured by 4,069.4 MW, which is equal to 2.5 percent of 162,777.4, the demand adjusted for FRR.

Effective for the 2017/2018 Delivery Year, the Minimum Annual and Extended Summer Resource Requirements were replaced by Limited and Sub-Annual Resource Constraints.[43] The Limited Resource Constraint limited the quantity of Limited DR that can be procured, and the Sub-Annual Constraint limited the quantity of Limited DR and Extended Summer DR that could be procured. Under the prior rules, the quantity of Limited DR and Extended Summer DR were not capped, as intended, at a fixed MW level. Under the prior rules, if the Minimum Annual Resource Requirement constraint were binding, the Extended Summer and Limited DR products would fill in the balance of capacity needed to meet the VRR curve. The modifications to the rules for the 2017/2018 Delivery Year reduced the impact of Limited and Extended Summer DR on market outcomes compared to what the impact would have been without the rule changes.

Effective March 2, 2014, every DR provider must submit a DR Sell Offer Plan, consisting of a completed template document with certain required information and a DR Offer Certification Form, at least 15 business days prior to an RPM Auction.[44] The DR plan enhancements are meant to standardize the information requirements for offering planned DR, increase the likelihood that offers are based on physical assets and reduce the level of speculative offers. However, the DR plan enhancements did not go far enough to ensure that DR offers are based on physical assets at the time of the offer and therefore did not address the issue of speculative offers that are replaced in incremental auctions.

Effective for the 2018/2019 and subsequent Delivery Years, the Extended Summer and Limited DR products are eliminated. For a transition period during the 2018/2019 and 2019/2020 Delivery Years, PJM procured two product types, Capacity Performance and Base Capacity. Effective for the 2018/2019 and the 2019/2020 Delivery Years, a Base Capacity Demand Resource Constraint and a Base Capacity Resource Constraint, which replaced the Sub-Annual Resource Constraint and Limited Resource Constraint, were established for each modeled LDA. These maximum quantities were set for reliability purpose to limit the quantity procured of the inferior products, including Base Capacity Generation Resources, Base Capacity Demand Resources, and Base Capacity Energy

43 146 FERC ¶ 61,052 (2014).

44 146 FERC ¶ 61,150 (2014).

Efficiency Resources. Effective with the 2020/2021 and subsequent delivery years, PJM will procure a single capacity product, Capacity Performance.

Effective for the 2018/2019 and subsequent delivery years, the Short Term Resource Procurement Target was eliminated. Under the prior rules, application of the Short-Term Resource Procurement Target meant that 2.5 percent of the reliability requirement was removed from the demand curve (VRR curve).

Credit Limited Offers

Capacity Market Sellers must establish credit if offering any Planned Capacity Resource, Qualified Transmission Upgrade, or an external resource without firm transmission in an RPM Auction. Effective with the 2014/2015 and subsequent delivery years, the RPM market design also included the implementation of credit limited offers, which allow a Capacity Market Seller to specify a Maximum Post-Auction Credit Exposure (MPCE) in dollars for a planned resource using a non-coupled offer type. Capacity Market Sellers utilizing coupled sell offers cannot use the MPCE option. The intent of credit limited offers is to allow Capacity Market Sellers to better manage their credit requirement by specifying the maximum amount of credit they are willing to incur and to provide the service of determining the maximum cleared MW given the MPCE limit. For DR, 20 percent of MW offered used MPCE while for Energy Efficiency (EE) resources, eight percent of MW offered used MPCE.

Under the rule incorporating the ability to set an MPCE, the RPM market clearing process must yield a solution where no resource’s Post-Auction Credit Exposure (PCE) exceeds its MPCE for credit limited offers. The Post-Auction Credit Rate is a function of the resource clearing price. As a result, the RPM auction must be solved iteratively until no MPCE violations exist.

Effective with the 2012/2013 through 2019/2020 Delivery Years, the RPM credit rate prior to the posting of the BRA results for proposed capacity resources other than Capacity Performance Resources is equal to the number of days in the delivery year times the greater of $20 per MW-day or 30 percent of the LDA net Cost of New Entry, and the RPM credit rate after posting the BRA results is the number of days in the delivery year times the greater of $20 per MW-day or 20 percent of the LDA resource clearing price for the relevant product type. Effective for the 2018/2019 and subsequent delivery years, the RPM credit rate prior to the posting of the BRA results for proposed Capacity Performance Resources is equal to the number of days in the delivery year times the greater of $20 per MW-day or 50 percent of the LDA net Cost of New Entry, and the RPM credit rate after posting the BRA results is the number of days in the delivery year times the greater of $20 per MW-day, 20 percent of the LDA resource clearing price for the relevant product type, or the lesser of 50 percent of the LDA net Cost of New Entry or 150 percent of the LDA net Cost of New Entry minus the LDA CP clearing price. The

MPCE option permits participants to offer capacity when they could not otherwise offer capacity based on an uncertain RPM credit rate that could vary with clearing prices.

Other Changes Affecting Supply and Demand

On December 16, 2011, the U.S. Environmental Protection Agency (EPA) issued its Mercury and Air Toxics Standards rule (MATS), a final rule setting maximum achievable control technology (MACT) emissions standards for hazardous air pollutants (HAP) from coal and oil fired electric utility steam generating units, pursuant to section 112(d) of the Clean Air Act.[45] The rule required compliance by April 16, 2015, with the possibility of one year extensions being granted to individual generation owners.[46]

The state of New Jersey has separately addressed NO_X emissions on peak energy days with a rule that defines peak energy usage days, referred to as High Electric Demand Days or HEDD.[47] The rule implemented performance standards effective on May 1, 2015, just prior to the commencement of the 2015/2016 Delivery Year.

MMU Method

The MMU reviewed the following inputs to and results of the 2020/2021 RPM Base Residual Auction:[48]

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

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45 *National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234, 77 Fed. Reg. 9304 (February 16, 2012).

46 *Id*. at 9465.

47 N.J.A.C. § 7:27–19.

48 Unless otherwise specified, all volumes and prices are in terms of unforced capacity (UCAP), which is calculated as installed capacity (ICAP) times (1-EFORd) for generation resources and as ICAP times the Forecast Pool Requirement (FPR) for Demand Resources and Energy Efficiency Resources. The EFORd values in this report are the EFORd values used in the 2020/2021 RPM Base Residual Auction.

- Net Revenues. Calculated actual unit-specific net revenue from PJM energy and ancillary service markets for each PJM Generation Capacity Resource for the three year period from 2014 through 2016;[49]

- Minimum Offer Price Rule (MOPR). Reviewed requests for Unit-Specific Exceptions, Competitive Entry Exemptions, and Self-Supply Exemptions;

- 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, 2016, 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, the Variable Resource Requirement (VRR) curves, and the Base Capacity Constraints and Base Capacity Demand Resource Constraints;[50]

- 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.

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49 Net revenue values for the 2020/2021 RPM BRA were calculated consistent with the FERC order effective at the time. *See Order on Section 206 Investigation*, 154 FERC ¶ 61,151 (2016).

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

Market Structure Tests

As shown in Table 4, all participants in the RTO, MAAC, EMAAC, ComEd, and DEOK RPM markets failed the TPS test.[51] 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. Not mitigating sell offers for generation resources that did not, absent mitigation, increase the market clearing price had no impact on the clearing prices in the auction but did affect seasonal make whole payments paid to seasonal offers. The result was an exercise of market power as a result of a failure of the rules. While the dollar magnitude of the impact was limited in this auction, the rules should be fixed to ensure that market power cannot be exercised in future auctions. Under the seasonal capacity rules, the optimization considers the total cost of clearing a seasonal offer in combination with an offer for the opposite season, and this can result in clearing seasonal sell offers with prices greater than the clearing price and making seasonal make whole payments based on those high prices. The MMU recommends that the RPM market power mitigation rule be modified to apply offer caps in all cases when the three pivotal supplier test is failed and the sell offer is greater than the offer cap. This will ensure that market power does not result in an increase in make whole payments as occurred in the 2020/2021 BRA.

Market power mitigation was applied to the Capacity Performance sell offers of zero generation capacity resources in the 2020/2021 RPM Base Residual Auction. All offers were less than the defined offer caps or did not increase market 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.[52] 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.

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

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

Table 4 presents the results of the TPS test and the one pivotal supplier test. A generation owner or owners are pivotal if the capacity of the owners' generation facilities is needed to meet the demand for capacity. The results of the TPS are measured by the Residual Supply Index (RSI_3). The RSI_x is a general measure that can be used with any number of pivotal suppliers. The TPS test uses three pivotal suppliers. The subscript denotes the number of pivotal suppliers included in the test. If the RSI_x is less than or equal to 1.0, the supply owned by the specific generation owner, or owners, is needed to meet market demand and the generation owners are pivotal suppliers with a significant ability to influence market prices. If the RSI_x is greater than 1.0, the supply of the specific generation owner or owners is not needed to meet market demand and those generation owners have a reduced ability to unilaterally influence market price.[53]

Table 4 RSI results: 2020/2021 RPM Base Residual Auction[54]

	$RSI_{1\ 1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
RTO	0.81	0.69	119	119
MAAC	0.67	0.77	24	24
EMAAC	0.45	0.18	21	21
ComEd	0.47	0.20	14	14
DEOK	0.00	0.00	1	1

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 2020/2021 RPM Base Residual Auction.[55] Market power mitigation measures are applied to Existing Generation Capacity Resources such that the sell offer is set equal to the defined offer cap when the Capacity

53 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.

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

55 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).

Market Seller fails the market structure test for the auction, the submitted sell offer exceeds the defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price.[56] For RPM Base Residual Auctions, for Base Capacity prior to the 2020/2021 Delivery Year, offer caps are defined as avoidable costs less PJM market revenues, or the opportunity costs associated with selling capacity outside the PJM market. For Capacity Performance Resources, offer caps as defined as the applicable zonal net Cost of New Entry (CONE) times (B) where B is the average of the Balancing Ratios (B) during the Performance Assessment Hours in the three consecutive calendar years that precede the Base Residual Auction for such Delivery Year unless avoidable costs exceed this level, or opportunity costs.

Table 5 shows the zonal net CONE times B offer caps for the 2019/2020 and 2020/2021 RPM Base Residual Auctions. In all zones except EKPC, the net CONE times B offer cap values decreased from the 2019/2020 RPM Base Residual Auction.

Avoidable costs are the costs that a generation owner would not incur if the generating unit did not operate for one year, in particular the Delivery Year.[57] In the calculation of avoidable costs, there is no presumption that the unit would retire as the alternative to operating, although that possibility could be reflected if the owner documented that retirement was the alternative. 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). Avoidable cost-based offer caps are defined to be net of revenues from all other PJM markets and unit-specific bilateral contracts. For Capacity Performance Resources, 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 delivery years prior to 2020/2021, by selecting the default ACR values. The specific components of avoidable costs are defined in the PJM Tariff.[58]

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).[59] AFAE is available for Capacity Performance

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56 OATT Attachment DD § 6.5.

57 OATT Attachment DD § 6.8 (b).

58 OATT Attachment DD § 6.8 (a).

59 151 FERC ¶ 61,208.

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

The opportunity cost option allows Capacity Market Sellers to input 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 3, 1,114 generation resources submitted Capacity Performance offers in the 2020/2021 RPM Base Residual Auction. The MMU calculated offer caps for 14 generation resources that submitted Capacity Performance offers. Unit-specific ACR-based offer caps were calculated for 14 generation resources (1.3 percent) including 11 generation resources (1.0 percent) with an Avoidable Project Investment Recovery Rate (APIR) and a CPQR component and three generation resources (0.3 percent) with an APIR component and no CPQR component. Of the 1,114 generation resources offered as Capacity Performance, 956 generation resources had the net CONE times B offer cap, zero generation resources had opportunity cost-based offer caps, 12 Planned Generation Capacity Resources had uncapped offers, 18 generation resources had uncapped planned uprates plus net CONE times B offer cap for the existing portion of the units, two generation resource had an uncapped planned uprate plus price taker status for the existing portion of the unit, while the remaining 112 generation resources were price takers.

As shown in Table 7, the weighted average gross ACR for units with APIR was $498.15 per MW-day for Capacity Performance Resources. Under CP, only high ACR units have a reason to request ACR based offer caps. The weighted average offer caps, net of net revenues, for units with APIR was $209.18 per MW-day for Capacity Performance Resources.

The APIR component added an average of $235.67, for Capacity Performance Resources, to the ACR value of the APIR units.[60] The maximum APIR effect ($464.71 per MW-day

[60] The net revenue offset for an individual unit could exceed the corresponding ACR. In that case, the offer cap would be zero.

for Capacity Performance Resources) is the maximum amount by which an offer cap was increased by APIR.

The CPQR component added an average of $0.23 per MW-day, for Capacity Performance Resources, to the ACR value of the APIR units.

There were no unit-specific ACR based offer caps without an APIR component submitted for Capacity Performance Resources.

Market power mitigation measures are applied to MOPR Screened Generation Resources such that the sell offer is set equal to the MOPR Floor Offer Price when the submitted sell offer is less than the MOPR Floor Offer Price and an exemption or exception was not granted, or the sell offer is set equal to the agreed upon minimum level of sell offer when the sell offer is less than the agreed upon minimum level of sell offer based on a Unit-Specific Exception. As shown in Table 8, of the 12,171.0 ICAP MW of MOPR Competitive Entry Exemption requests, all requests were granted. Of the 3,301.2 MW offered for MOPR Screened Generation Resources, 2,646.7 MW cleared and 654.5 MW did not clear.

Tables for Offer Caps and Offer Floors

Table 5 Net CONE times B: 2019/2020 and 2020/2021 RPM Base Residual Auctions

	2019/2020					2020/2021					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	$364.30	$84.52	$279.78	0.81	$226.62	$367.97	$87.64	$280.33	0.79	$220.06	$3.68	$3.12	$0.55	(0.03)	($6.56)
AEP	$362.47	$96.93	$265.54	0.81	$215.09	$365.52	$103.48	$262.03	0.79	$205.69	$3.04	$6.55	($3.51)	(0.03)	($9.40)
AP	$362.47	$128.99	$233.48	0.81	$189.12	$365.52	$135.36	$230.15	0.79	$180.67	$3.04	$6.37	($3.33)	(0.03)	($8.45)
ATSI	$362.47	$115.84	$246.63	0.81	$199.77	$365.52	$121.55	$243.96	0.79	$191.51	$3.04	$5.71	($2.67)	(0.03)	($8.26)
BGE	$366.94	$165.54	$201.39	0.81	$163.13	$374.61	$208.03	$166.58	0.79	$130.77	$7.67	$42.49	($34.81)	(0.03)	($32.36)
ComEd	$362.47	$55.70	$306.77	0.81	$248.48	$365.52	$57.44	$308.07	0.79	$241.83	$3.04	$1.74	$1.30	(0.03)	($6.65)
DAY	$362.47	$103.43	$259.04	0.81	$209.82	$365.52	$110.37	$255.14	0.79	$200.28	$3.04	$6.94	($3.90)	(0.03)	($9.54)
DEOK	$362.47	$94.01	$268.46	0.81	$217.45	$365.52	$101.67	$263.85	0.79	$207.12	$3.04	$7.66	($4.61)	(0.03)	($10.33)
DLCO	$362.47	$94.78	$267.69	0.81	$216.83	$365.52	$98.56	$266.96	0.79	$209.56	$3.04	$3.77	($0.73)	(0.03)	($7.27)
DPL	$364.30	$119.34	$244.96	0.81	$198.42	$367.97	$129.80	$238.17	0.79	$186.96	$3.68	$10.47	($6.79)	(0.03)	($11.46)
Dominion	$362.47	$84.06	$278.41	0.81	$225.51	$365.52	$88.29	$277.23	0.79	$217.63	$3.04	$4.22	($1.18)	(0.03)	($7.88)
EKPC	$362.47	$108.90	$253.57	0.81	$205.39	$365.52	$89.03	$276.49	0.79	$217.04	$3.04	($19.87)	$22.92	(0.03)	$11.65
External	$365.17	$85.62	$279.55	0.81	$226.44	$368.44	$94.80	$273.64	0.79	$214.81	$3.27	$9.18	($5.91)	(0.03)	($11.63)
JCPL	$364.30	$119.27	$245.02	0.81	$198.47	$367.97	$123.24	$244.73	0.79	$192.11	$3.68	$3.97	($0.29)	(0.03)	($6.36)
Met-Ed	$366.97	$106.89	$260.08	0.81	$210.66	$365.66	$117.20	$248.45	0.79	$195.03	($1.31)	$10.31	($11.63)	(0.03)	($15.63)
PECO	$364.30	$104.94	$259.36	0.81	$210.08	$367.97	$113.53	$254.44	0.79	$199.74	$3.68	$8.59	($4.92)	(0.03)	($10.34)
PENELEC	$366.97	$213.39	$153.58	0.81	$124.40	$365.66	$235.26	$130.40	0.79	$102.36	($1.31)	$21.87	($23.18)	(0.03)	($22.04)
PPL	$366.97	$107.56	$259.41	0.81	$210.12	$365.66	$115.95	$249.71	0.79	$196.02	($1.31)	$8.38	($9.70)	(0.03)	($14.10)
PSEG	$364.30	$81.02	$283.28	0.81	$229.46	$367.97	$81.28	$286.69	0.79	$225.05	$3.68	$0.27	$3.41	(0.03)	($4.41)
Pepco	$366.94	$138.83	$228.11	0.81	$184.77	$374.61	$163.01	$211.60	0.79	$166.11	$7.67	$24.18	($16.51)	(0.03)	($18.66)
RECO	$364.30	$87.24	$277.06	0.81	$224.42	$367.97	$85.67	$282.30	0.79	$221.61	$3.68	($1.57)	$5.24	(0.03)	($2.81)

Table 6 ACR statistics: 2020/2021 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)	3	0.3%
Unit specific ACR (APIR and CPQR)	11	1.0%
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	956	85.8%
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	18	1.6%
Uncapped planned uprates and price taker	2	0.2%
Uncapped planned generation resources	12	1.1%
Existing generation resources as price takers	112	10.1%
Total Generation Capacity Resources offered	1,114	100.0%

Table 7 APIR statistics: 2020/2021 RPM Base Residual Auction[61] [62] [63]

	Weighted-Average ($ per MW-day UCAP)
Non-APIR units	
ACR	
Net revenues	
Offer caps	
APIR units	
ACR	$498.15
Net revenues	$277.52
Offer caps	$209.18
APIR	$235.67
CPQR	$0.23
Maximum APIR effect	$464.71

Table 8 MOPR statistics: 2020/2021 RPM Base Residual Auction

Request Type	Requested ICAP (MW)	Granted ICAP (MW)	Offered ICAP (MW)	Offered UCAP (MW)	Cleared UCAP (MW)
Competitive Entry Exemption	12,171.0	12,171.0	3,212.5	3,161.1	2,646.7
Self-Supply Exemption	0.0	0.0	0.0	0.0	0.0
Unit-Specific Exception	0.0	0.0	0.0	0.0	0.0
Other MOPR Screened Generation Resources	0.0	0.0	142.0	140.1	0.0
Total	12,171.0	12,171.0	3,354.5	3,301.2	2,646.7

61 The weighted average offer cap can be positive even when the weighted average net revenues are higher than the weighted average ACR because the unit-specific offer caps are never less than zero. On a unit basis, if net revenues are greater than ACR the offer cap is zero.

62 For reasons of confidentiality, the APIR statistics do not include opportunity cost-based offer cap data.

63 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 2020/2021 BRA, waste coal resources are included in the coal fired category.

Competitive Capacity Performance Offers

The competitive offer of a Capacity Performance resource is based on a market seller's expectations of a number of variables, some of which are resource specific: the resource's net going forward costs (Net ACR); and the resource's performance during performance assessment hours (A) in the delivery year.[64]

The competitive offer of a Capacity Performance resource is also based on a market seller's expectations of system level variables: the number of performance assessment hours (PAH) in a delivery year (H) where the resource is located; the level of performance required to meet its capacity obligation during those performance assessment hours, measured as the average Balancing Ratio (B); and the level of the bonus performance payment rate (CPBR) compared to the nonperformance charge rate (PPR). The level of bonus performance payment rate depends on the level of underperforming MW net of the underperforming MW excused by PJM during performance assessment hours for reasons defined in the PJM OATT.[65]

Attachment B explains the derivation of the competitive offer of a Capacity Performance resource. The default offer cap defined in the PJM tariff, Net CONE times the average Balancing Ratio, is based on a number of assumptions:

1. The Net ACR of a resource is less than its expected energy only bonuses:

$$ACR \leq \sum_{i=1}^{H} (CPBR_i \times A_i)$$

$$or\ ACR \leq CPBR \times H \times \bar{A}$$

2. The expected number of performance assessment hours equals 30. (H = 30)
3. The expected value of the bonus performance payment rate (CPBR) is equal to the nonperformance charge rate (PPR)
4. The average expected performance of the resource during performance assessment hours ($\bar{A}$)

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64 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.

65 OATT Attachment DD § 10A (d).

If the expectations of a market seller on any of these variables are different from the stated assumptions, the competitive offer of such a resource is different from Net CONE times B. This is illustrated in an example. The example uses the Net CONE and average balancing ratio value used for the default offer cap published by PJM for the 2020/2021 BRA.[66]

Example Competitive Offer Calculation

Consider a resource in the AEP Zone with:

- Net ACR of $50,000 per ICAP MW per year, or $136.99 per ICAP MW per day.
- Expected average performance ($\bar{A}$) of 75 percent during performance assessment hours.
- Expected number of performance assessment hours, H, is 30.
- Expects that 20 percent of underperformance MWh are excused on average (in other words, bonus performance payment rate is equal to 80 percent of the nonperformance charge rate).

Without a capacity commitment, the resource would have earned bonus payments during all the performance assessment hours for its entire performance.

Energy only bonus revenues = $CPBR \times H \times \bar{A}$

Using a bonus performance rate of 0.8 times the nonperformance charge rate for the AEP zone, CPBR ($ per MWh) = $3,188.03 × 0.8 = $2,550.425 per MWh

Energy only bonus revenues = 2,550.425 ($/MWh) × 30 (hours/year) × 0.75

= $57,385 per MW–year

The Net ACR of the resource ($50,000 per MW-year) is less than its expected energy only bonus revenues ($57,385 per MW-year). The competitive offer of such a resource is:

$$p = CPBR \times H \times \bar{A} + PPR \times H \times (\bar{B} - \bar{A})$$

In other words, the competitive offer is the opportunity cost of taking on the capacity obligation which equals the sum of the energy only bonuses it would have earned

66 *See* PJM. “Final CP Market Seller Offer Cap Values,” <http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2020-2021-final-cp-market-seller-offer-cap-values.ashx?la=en>.

$(CPBR \times H \times \bar{A})$ and the net nonperformance charges it would incur by taking on the capacity obligation $(PPR \times H \times (\bar{B} - \bar{A}))$. This is because its expected average performance at 75 percent is less than the expected average balancing ratio of 78.5 percent. The competitive offer is calculated as:

$$p = (0.8 \times PPR) \times 30 \times 0.75 + PPR \times 30 \times (0.785 - 0.75)$$

p = $60,732 per MW-year or $166.39 per MW-day

In comparison, the default offer cap for the resource, Net CONE times B is:

Default offer cap = $75,078 per MW-year or $205.69 per MW-day

This example illustrates how, when a market seller's expectation on just one variable is different from the assumptions used in the default offer cap calculation (in this case the bonus payment rate is estimated as 80 percent of the nonperformance charge rate), the competitive offer of a resource is lower than the default offer cap. This means that the default offer cap overstates the competitive offer for such a resource. The resource is permitted to use the higher default offer cap rather than the competitive offer. This also illustrates that a resource subject to MOPR could support an offer less than the default offer cap.

As illustrated in the example, a market seller can similarly have different expectations for the other variables in the competitive offer calculation: A, B and H. These expectations can lead to competitive offers below Net CONE times B, the default offer cap. The offers below the default offer cap indicate that market sellers of Capacity Performance resources in PJM have different expectations than are assumed in the derivation of Net CONE times B: (i) the number of performance assessment hours (H) will be less than 30; (ii) the expected average performance of resources (A) will increase under the Capacity Performance framework, and; (iii) locational events where balancing ratio (B) is expected to be different from the historical average of 78.5 percent that PJM used for the default offer cap calculation.

Table 9 shows sample calculations for a High ACR resource in the AEP, ATSI, Dayton, and Dominion zones in PJM all of which cleared at the rest of RTO price of $76.53 per MW-day in the 2020/2021 BRA. The competitive offers calculated in Table 9 are close to the clearing price observed for these zones in the 2020/2021 BRA. The assumptions used for the competitive offer calculation in Table 9 are:

- Net ACR = $30,000 per MW-year
- H = 5;
- Expected average B = 78.5 percent;

- Expected average A = 95 percent;
- Expected average bonus payment rate = 80 percent of the nonperformance charge rate.

Table 9 Competitive offers for hypothetical resources in the rest of RTO zones[67]

Zone	Net Cone ($/MW-Day) (ICAP Terms)	Balancing Ratio, B (%)	Expected number of Performance Assessment Hours, H (hours/year)	Unit specific Availability A (%) (hypothetical resource)	Non-Performance Charge Rate (PPR) in $/MWh (Net CONE *(365/30))	Capacity Performance Bonus Rate (CPBR) assumed to be 80% of PPR	Expected Bonus Revenues as an Energy Only Resource ($ per MW-year)	Competitive Offer of a High ACR resource using CPBR = 80% of PPR	Default Offer Cap (Net CONE*B)
AEP	$262.0	78.5%	5	95%	$3,188.0	$2,550.4	$12,114.5	$76.4	$205.7
ATSI	$244.0	78.5%	5	95%	$2,968.2	$2,374.5	$11,279.1	$76.8	$191.5
DAY	$255.1	78.5%	5	95%	$3,104.2	$2,483.4	$11,796.0	$76.6	$200.3
DOM	$277.2	78.5%	5	95%	$3,373.0	$2,698.4	$12,817.3	$76.1	$217.6

Table 10 shows sample calculations for a Low ACR resource in the PSEG, PECO and JCPL zones in PJM all of which cleared at the EMAAC price of $187.8 per MW-day in the 2020/2021 BRA. The competitive offers calculated in Table 10 are close to the clearing price observed for these zones in the 2020/2021 BRA. The assumptions used for the competitive offer calculation in Table 10 are:

- H = 25;
- Expected average B = 90 percent;
- Expected average A = 85 percent;
- Expected average bonus payment rate = 90 percent of the nonperformance charge rate.

[67] The Non Performance Charge Rate is defined in the PJM OATT as Net CONE for the LDA (in $ per MW-day ICAP) times 365 divided by 30, regardless of whether the delivery year includes a leap year. See OATT Attachment DD § 10A (e).

Table 10 Competitive offers for hypothetical resources in the EMAAC zones

Zone	Net Cone ($/MW-Day) (ICAP Terms)	Balancing Ratio, B (%)	Expected number of Performance Assessment Hours, H (hours/year)	Unit specific Availability A (%) (hypothetical resource)	Non-Performance Charge Rate (PPR) in $/MWh (Net CONE *(365/30))	Capacity Performance Bonus Rate (CPBR) assumed to be 90% of PPR	Expected Bonus Revenues as an Energy Only Resource ($ per MW-year)	Competitive Offer of a Low ACR resource using CPBR = 90% of PPR	Default Offer Cap (Net CONE*B)
PSEG	$286.7	90.0%	25	85%	$3,488.1	$3,139.3	$66,709.2	$194.7	$258.0
PECO	$254.4	90.0%	25	85%	$3,095.7	$2,786.1	$59,205.0	$172.8	$229.0
JCPL	$244.7	90.0%	25	85%	$2,977.5	$2,679.8	$56,945.6	$166.2	$220.3

While Table 9 and Table 10 illustrate a set of assumptions that lead to competitive offer prices close to the observed clearing prices, it is important to note that the assumptions for the variables involved (A, B, H and bonus payment dilution) can vary depending on a market seller's view of the system outcomes as well as the performance of its own specific resources. For example, the number of performance assessment hours in the previous three delivery years (June 1, 2014 through May 31, 2017) was zero. Based on the available data, if a market seller expects that the number of performance assessment hours (H) in the future delivery year is significantly lower than the initial PJM estimate of 30, an energy only resource may not have the opportunity to earn enough capacity bonus revenues to cover its expected net going forward costs (Net ACR). For such a resource, the competitive offer would be its Net ACR adjusted with any potential CP nonperformance charges or bonuses. These examples illustrate that offers below the tariff defined offer cap of Net CONE times B are consistent with competitive behavior. Market sellers have had no experience operating under the Capacity Performance design and their assumptions will evolve as they gain more experience with the implementation of the Capacity Performance design.

Bonus Performance Payment Rate Dilution

An important consideration in a competitive offer calculation is the expectation about the capacity bonus performance payments. If market sellers expect that PJM will excuse resources that underperform, it leads to dilution of the bonus performance rate, compared to the nonperformance charge rate. Another reason for dilution of bonus performance payments is retroactive replacement transactions. Current market rules allow capacity resources that underperform, with certain restrictions on ownership and location, to enter into retroactive replacement transactions with resources that may have over performed during a performance assessment hour. Such a transaction allows the underperforming resource to avoid paying nonperformance charges by adjusting its expected performance after a performance assessment hour. Such a provision leads to fewer nonperformance charges collected and consequently, fewer bonus performance payments.

Dilution of bonus performance generally leads to lower competitive offers, since the opportunity of earning bonuses as an energy only resource decreases with a lower bonus performance payment rate. Offers and clearing prices in the capacity market reflect market sellers' expectations about PJM's implementation of the Capacity Performance design. The Capacity Performance design only works as intended if PJM actually implements the no excuses approach ordered by the Commission and ensures that resources can only meet their obligation and avoid penalties by actually performing during the most critical times.

Generation Capacity Resource Changes

As shown in Table 5, Capacity Performance offers were submitted for 1,114 generation resources in the 2020/2021 RPM Base Residual Auction, compared to 1,200 generation resources offered in the 2019/2020 RPM Base Residual Auction, a net decrease of 86 generation resources. This was a result of 121 fewer generation resources offered offset by 35 additional generation resources offered.

The 35 additional generation resources offered consisted of 16 new resources (2,496.2 MW), six additional resources imported (MW), five resources that were previously entirely FRR committed (271.4 MW), four resources that were unoffered in the 2019/2020 BRA (495.5 MW), two reactivated resources (5.3 MW), and two additional resources resulting from the disaggregation of RPM resources.[68]

The 16 new Generation Capacity Resources consisted of eight solar resources (64.0 MW), three combined cycle resources (2,382.5 MW), three diesel resources (24.3 MW), and two wind resources (25.4 MW).

The 121 fewer generation resources offered consisted of 82 intermittent resources not offered (863.9 MW), 17 deactivated resources (4,123.8 MW), 14 generation resources excused from offering for reasons other than retirement (218.7 MW), four external resources not offered (166.5 MW), additional resources committed fully to FRR, Planned Generation Capacity Resources not offered, and capacity storage resources not offered.[69] Table 11 shows Generation Capacity Resources for which deactivation requests have been submitted which affected supply between the 2019/2020 BRA and the 2020/2021 BRA.

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

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

Table 11 Generation Capacity Resource deactivations

Resource Name	LDA	ICAP (MW)	Date Deactivation Notice Submitted	Projected or Actual Deactivation Date
WAGNER 2	BGE	118.0	16-Jun-15	01-Jun-20
WARREN COUNTY LF	EMAAC	0.1	01-Mar-16	01-Jun-16
BAYSHORE 1	ATSI	136.0	22-Jul-16	01-Oct-20
SAMMIS 1	ATSI	160.0	22-Jul-16	31-May-20
SAMMIS 2	ATSI	160.0	22-Jul-16	31-May-20
SAMMIS 3	ATSI	160.0	22-Jul-16	31-May-20
SAMMIS 4	ATSI	160.0	22-Jul-16	31-May-20
HUDSON 2	PSEG North	565.0	05-Oct-16	01-Jun-17
MERCER 1	PSEG	316.0	05-Oct-16	01-Jun-17
MERCER 2	PSEG	316.0	05-Oct-16	01-Jun-17
KILLEN	DAY	600.0	17-Mar-17	01-Jun-18
KILLEN GT1	DAY	18.0	17-Mar-17	01-Jun-18
STUART 1	DAY	577.0	17-Mar-17	30-Sep-17
STUART 2	DAY	577.0	17-Mar-17	01-Jun-18
STUART 3	DAY	577.0	17-Mar-17	01-Jun-18
STUART 4	DAY	577.0	17-Mar-17	01-Jun-18
STUART DIESEL 1-4	DAY	9.2	17-Mar-17	01-Jun-18

RTO Market Results

Total Offers

Table 12 shows total RTO offer data for the 2020/2021 RPM Base Residual Auction. All MW values stated in the RTO section include all nested LDAs.[70] [71] As shown in Table 17, total internal RTO unforced capacity (UCAP), excluding generation winter capacity, increased 662.9 MW (0.3 percent) from 200,065.5 MW in the 2019/2020 RPM BRA to 200,728.4 MW.

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. The 662.9 MW increase in internal capacity was a result of net generation capacity

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70 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.

71 Maps of the LDAs can be found in the *2016 State of the Market Report for PJM*, Appendix A, "PJM Geography."

modifications (cap mods) (1,218.7 MW), net DR capacity changes (-2,231.4 MW), net EE modifications (636.6 MW), the EFORd effect due to lower sell offer EFORds (1,027.6 MW), and the DR and EE effect due to a higher Load Management UCAP conversion factor (11.4 MW).[72]

As shown in Table 19, total internal RTO unforced winter capacity for November through April increased 825.2 MW from 0.0 MW in the 2019/2020 BRA to 825.2 MW in the 2020/2021 BRA. The 825.2 MW increase in winter capacity was a result of net generation winter capacity modifications (825.2 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 2020/2021 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.[73] 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.[74] 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

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72 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 2019/2020 BRA, this conversion factor was 1.0881. For the 2020/2021 BRA, this conversion factor was 1.0892. 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," Rev. 08 (July 1, 2017) at 12-14.

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

74 "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," Rev. 12 (January 1, 2017) at 12. The manual states "the end of the next Delivery Year."

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 192,723.4 MW compared to 190,419.4 MW in the 2019/2020 RPM Base Residual Auction.[75] Generation winter capacity increased by 409.2 MW, FRR volumes decreased by 603.5 MW, and imports increased by 628.4 MW.[76] Of the 5,390.7 MW of imports, 428.9 MW were committed to an FRR capacity plan and 4,961.8 MW were offered in the auction, of which 3,997.2 MW cleared. Of the cleared imports, 1,671.2 MW (50.6 percent) were from MISO. RPM capacity was reduced by exports of 1,293.3 MW, an increase of 4.7 MW from the 2019/2020 RPM Base Residual Auction. Of total exports, 669.8 MW (51.8 percent) were to the NYISO, 544.3 MW (42.1 percent) were to MISO, and 79.2 MW (6.1 percent) were to Duke Energy Carolinas.

In addition, RPM capacity was reduced by 1,021.0 MW of Planned Generation Capacity Resources which were not subject to the RPM must offer requirement, by 1,889.0 MW of intermittent resources and 668.4 MW of capacity storage resources which were not subject to the CP must offer requirement, and by 3,263.4 MW which were excused from the RPM must offer requirement. The excused Existing Generation Capacity Resources were the result of plans for retirement (3,048.1 MW), and the resource being reasonably expected to be physically incapable of satisfying the requirements of a Capacity Performance Resource (215.3 MW).[77] Subtracting 0.0 MW of FRR optional volumes not offered, a decrease of 123.7 MW from the 2019/2020 RPM Base Residual Auction, 2,489.3 MW of DR and EE not offered, and 17.7 MW of unoffered generation winter capacity resulted in 182,081.2 MW that were available to be offered in the RPM Auction, a decrease of 3,458.3 MW from the 2019/2020 RPM Base Residual Auction.[78] [79] After

75 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.

76 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.

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

78 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

accounting for these factors, 0.0 MW were not offered and unexcused in the RPM Auction.

Offered MW decreased 3,458.3 MW from 185,539.5 MW to 182,081.2 MW, while the overall RTO Reliability Requirement adjusted for FRR obligations, from which the demand curve is developed, decreased 2,737.1 MW from 157,092.4 MW to 154,355.3 MW. 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.[80] The 2,737.1 MW decrease in the RTO Reliability Requirement adjusted for FRR obligations from the 2019/2020 RPM Base Residual Auction was a result of a 3,392.6 MW decrease in the RTO Reliability Requirement not adjusted for FRR offset by a 655.5 MW decrease in the FRR obligation, shifting the RTO market demand curve to the left. The forecast peak load expressed in terms of installed capacity decreased 3,273.5 MW from the 2019/2020 RPM Base Residual Auction to 153,915.0 MW. The 3,392.6 MW decrease in the RTO Reliability Requirement was a result of a 3,561.9 MW decrease in the forecast peak load in UCAP terms holding the FPR constant at the 2019/2020 level offset by a 169.3 MW increase attributable to the change in the FPR. The increase in the FPR from the 2019/2020 RPM Base Residual Auction is a result of an increase in the IRM and a decrease in the Pool Wide Average EFORd.

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.[81] As shown in Table 15, the preliminary Net Load Price is $76.83 per MW-day in the RTO.

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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.

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

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

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

As shown in Table 13 and Table 14, the 163,399.0 MW of cleared and make whole generation and DR for the entire RTO, resulted in a reserve margin of 23.9 percent and a net excess of 9,043.7 MW over the reliability requirement of 154,355.3 MW (Installed Reserve Margin (IRM) of 16.6 percent).[82] [83] [84] [85] Net excess increased 321.7 MW from the net excess of 8,722.0 MW in the 2019/2020 RPM Base Residual Auction. Inclusion of cleared EE Resources in the calculations on the supply side and as an add back on the demand side results in a calculated reserve margin of 23.3 percent and a net excess of 8,520.3 MW over the reliability requirement of 154,355.3 MW. As shown in Figure 1, the downward sloping VRR demand curve resulted in a clearing price for Capacity Performance Resources of $76.53 per MW-day.

If the market clears on a nonflexible supply segment, a sell offer that specifies a minimum block MW value greater than zero, the Capacity Market Seller will be assigned make whole 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.[86] The make whole payment for partially cleared resources equals the make whole 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.[87] [88] The market results in the 2020/2021 BRA

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

83 The IRM increased from 16.5 percent in the 2019/2020 RPM Base Residual Auction to 16.6 percent in the 2020/2021 RPM Base Residual Auction.

84 The 23.9 percent reserve margin does not include EE on the supply side or the EE add back on the demand side. This is how PJM calculates the reserve margin.

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

86 OATT Attachment DD § 5.14 (b).

87 OATT Attachment DD § 5.12 (a).

88 For more details on the make whole processing, see Attachment A.

did not include make whole MW and payments resulting from partially cleared resources. Make whole MW and payments can also occur for resources electing the New Entry Price Adjustment (NEPA) or Multi-Year Pricing Option.[89] [90] 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 a make whole payment.[91] The market results in the 2020/2021 BRA did not include make whole MW or payments related to NEPA or Multi-Year Pricing Option.

The market results in the 2020/2021 BRA did include seasonal make whole MW and payments. Under the seasonal capacity rules, the optimization considers the total cost of clearing a seasonal offer in combination with an offer for the opposite season, and this can and did result in clearing seasonal sell offers with prices greater than the clearing price and seasonal make whole payments being granted.

Table 20 shows offered and cleared MW by LDA, resource type, and season in the 2020/2021 RPM Base Residual Auction. Of the 170,925.8 MW of generation offers, 170,591.7 MW were for the annual season. Of the 9,113.0 MW of DR offers, 8,367.2 MW were for the annual season. Of the 2,042.4 MW of EE offers, 1,839.0 MW were for the annual season.

Table 21 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 summer, which were greater than the weighted average sell offer prices for annual. For DR and EE, the weighted average sell offer prices in RTO for annual 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 resources from market power mitigation.

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89 OATT Attachment DD § 5.14 (c) (2).

90 OATT Attachment DD § 6.8 (a).

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

Table 22 shows the offered MW by resource type, offer/product type, and price range as percent of net CONE times B in the 2020/2021 RPM Base Residual Auction. Capacity Performance generation offers between $0 per MW-day and 50 percent of net CONE times B increased by 7,164.8 MW from the 2019/2020 RPM Base Residual Auction.

Table 23 shows cleared MW by zone and fuel source. Of the 170,925.8 MW offered for generation resources, 155,772.8 MW cleared (91.1 percent). Of the 165,109.2 cleared MW in the entire RTO, 26,521.6 MW (16.1 percent) cleared in Dominion, followed by 23,960.3 MW (14.5 percent) in ComEd and 16,644.4 MW (10.1 percent) in AEP. Of the 155,772.8 cleared MW for generation resources in the entire RTO, 75,146.4 MW (48.2 percent) were gas resources, followed by 40,344.6 MW (25.9 percent) from coal resources and 27,391.0 MW (17.6 percent) from nuclear resources.

The 16,972.0 MW uncleared MW in the entire RTO were the result of offer prices which exceeded the clearing prices. Of the 16,972.0 uncleared MW in the entire RTO, 383.2 MW were EE offers, 1,435.9 MW were DR offers, and the remaining 15,152.9 MW were generation offers. Table 24 presents details on the generation offers that did not clear. Of the 15,152.9 MW of uncleared generation offers, 8,808.3 MW (58.1 percent) were for generation resources greater than 40 years old, and 6,344.6 MW (41.9 percent) were for generation resources less than or equal to 40 years old.

Table 25 shows the auction results for the prior two Delivery Years for the generation resources that did not clear some or all MW in the 2020/2021 BRA. Of the 388 generation resources that did not clear 15,152.9 MW in the 2020/2021 BRA, 152 of those generation resources did not clear 8,964.6 MW in RPM Auctions for the 2019/2020 Delivery Year. Of those 152 generation resources that did not clear MW in RPM Auctions for the 2020/2021 and 2019/2020 Delivery Years, 113 of those generation resources did not clear 3,742.9 MW in RPM Auctions for the 2018/2019 Delivery Year. Thus, 8,964.6 MW of capacity did not clear in two sequential auctions, but 3,742.9 MW did not clear in three sequential auctions.

Capacity Transfer Rights

Capacity Transfer Rights (CTRs) are used to return capacity market congestion revenues to load. Load pays for the transmission system through firm transmission charges and pays for 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 is equal to the Unforced Capacity imported into the LDA determined based on the results of the Base Residual Auction and Incremental Auctions, less any MW of CETL paid for directly by market participants which include 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.

For LDAs in which the RPM auctions for a Delivery Year resulted in a positive average weighted Locational Price Adder, an LSE with CTRs corresponding to the LDA is entitled to a payment equal to the Locational Price Adder multiplied by the MW of the LSEs' CTRs.

In the 2020/2021 RPM Base Residual Auction, MAAC had -755.9 MW of CTRs with a total value of -$2,623,808, EMAAC had 4,748.3 MW of CTRs with a total value of $176,485,896, ComEd had 1,192.7 MW of CTRs with a total value of $48,579,473, and DEOK had 2,619.7 MW of CTRs with a total value of $51,127,157.[92] EMAAC had 948 MW of ICTRs with a total value of $35,235,217. DEOK had 155 MW of ICTRs with a total value of $3,025,065.

The negative CTRs for MAAC represent capacity that cleared inside of MAAC that was assigned to load in the Rest of RTO. In the BRA, 65,817.9 MW cleared in the MAAC LDA. However the capacity obligation for MAAC LDA for the 2020/2021 delivery year was only 65,138.7 MW, 679.2 MW less than the cleared capacity.[93] The 679.2 MW that cleared in excess of the capacity obligation was assigned to load in Rest of RTO. There was also an additional 76.7 MW of grandfathered, outgoing CTRs for MAAC, bringing the total to -755.9 MW of CTRs. The outgoing CTRs are valued at the capacity price difference between MAAC and the RTO, which is negative. The clearing price in MAAC was $86.04 and the clearing price in RTO was $76.53.

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.[94] The first

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92 A negative value indicates that the amount of capacity cleared in the MAAC LDA exceeded the UCAP obligation for the MAAC LDA.

93 In the BRA, 8,800 MW cleared as imports from MAAC to EMAAC LDA. But CTR allocations are based on PJM's calculated capacity obligations by LDA. The imports calculated using the capacity obligation were 5,761.4. The inconsistency is due to the mismatch between the cleared MW in the BRA and the allocation of the capacity obligation. The CTRs are based on the allocation of the capacity obligation to each LDA, which is derived using the LDA's peak load scaling factors.

94 "PJM Manual 14B: PJM Region Transmission Planning Process, Attachment C: PJM Deliverability Testing Methods," Rev. 37 (April 28, 2017) at 61. Manual 14B indicates that all "electrically cohesive load areas" are tested.

step in this process is to determine the transmission import requirement into an LDA, called the Capacity Emergency Transfer Objective (CETO). This value, expressed in unforced megawatts, is the transmission import capability required for each LDA to meet the area reliability criterion of loss of load expectation of one occurrence in 25 years when the LDA is experiencing a localized 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 localized 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.[95]

Under the Tariff, PJM determines, in advance of each BRA, whether specific Locational Deliverability Areas (LDAs) will be modeled in the auction. Only modeled LDAs can price separate in an auction. 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.[96] 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."[97] A reliability requirement, a Variable Resource Requirement (VRR) curve, a Minimum Annual Resource Requirement, and a Minimum Extended Summer Resource Requirement are established for each modeled LDA.

95 "PJM Manual 18: PJM Capacity Market," Rev. 37 (April 27, 2017) at 13.

96 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.

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

The CETL levels and the CETL/CETO ratios do not determine or predict whether there will be prices separation for an LDA. Locational price differences result from the interaction between the CETL import limit and the supply curve 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 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.

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.

Table 26 shows the CETL and CETO values used in the 2020/2021 study compared to the 2019/2020 values. DAY and DEOK LDAs were modeled for the first time in the 2020/2021 BRA. The only CETL values for the modeled LDAs that changed significantly were MAAC and ComEd. The ComEd CETL decreased due to "a 345 kV transmission facility in the AEP system that experienced a modest loading increase in the 2020/2021 CETL studies due to several factors including the addition of RTEP baseline upgrades in the area."[98] The MAAC CETL decreased due to generation changes within the MAAC LDA, modeling changes following the termination of the ConED/PSEG wheel and reduction in assumed capacity imports from NYISO using firm or nonfirm transmission capacity.

PJM appears to recognize that it is not appropriate to include assumptions of any emergency imports, which from a market perspective are equivalent to capacity imports, from NYISO using either firm or nonfirm transmission in the CETL studies. To the extent that such capacity imports were assumed in the 2020/2021 BRA, the CETL used by PJM for the MAAC LDA was too high and should be reduced further.[99]

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98 See PJM "2020/2021 RPM Base Residual Auction Planning Period Parameters" <http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2020-2021-rpm-bra-planning-parameters-report.ashx> (February 13, 2017).

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

Table 27 shows the initial and final PJM CETL values for MAAC, EMAAC, PSEG, and PSEG North for the 2020/2021 BRA and the proposed CETL values. The proposed CETL values equal the PJM updated values. PJM introduced updates to the PJM Transmission Planning Process in August 2017. Under the updated rules, the CETL for PSEG was reduced from 8,001 MW to 6,474 MW. The CETL for PS-NORTH LDA was reduced from 4,264 to 2,955 MW. PJM explained that the updates in the CETL values are due to aligning the PSEG-NYISO PAR settings to be consistent with the new protocols established by PJM operations group following the termination of ConEd Wheel agreements.[100] The information that resulted in a reduction in the CETL values was available prior to the BRA and the proposed CETL values should have been calculated prior to the BRA and implemented in the BRA. The impacts of using CETL values that are too high in the 2020/2021 RPM Base Residual Auction are shown in Scenario 2.

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 four locationally binding constraints in the 2020/2021 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 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.

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 different 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.

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[100] See "CETO/CETL Education," presented at November 3, 2017 meeting of Special Planning Committee.

Impact of ComEd CETL

The ComEd CETL for the 2020/2021 RPM Base Residual Auction was 1,096.0 MW lower than the 2019/2020 ComEd CETL level, a decrease of 21.2 percent. Table 28 shows the results if the 2019/2020 CETL value for ComEd had been used in the 2020/2021 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 increased to $80.76 per MW-day, and the clearing quantity would have decreased to 164,954.6 MW. The clearing quantity of seasonal capacity would have remained the same at 397.9 MW. The MAAC clearing price would have decreased to $85.22 per MW-day, and the clearing quantity would have decreased to 65,797.7 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have remained the same at 90.6 MW. The EMAAC clearing price would have remained the same at $187.87 per MW-day, and the clearing quantity would have decreased to 29,594.9 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement remained the same at 0 MW. The ComEd clearing price would have decreased to $170.02 per MW-day, and the clearing quantity would have decreased to 22,961.4 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement remained the same at 148.9 MW. The DEOK clearing price would have remained the same at $130.00 per MW-day and the clearing quantity would have remained the same at 2,430.3 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 make whole MW, total RPM market revenues for the 2020/2021 RPM Base Residual Auction were $6,964,679,748. If the 2019/2020 CETL value for ComEd had been used in the 2020/2021 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2020/2021 RPM Base Residual Auction would have been $6,879,241,720, a decrease of $85,438,029, or 1.2 percent, compared to the actual results. From another perspective, the use of the 2020/2021 CETL value for ComEd resulted in a 1.2 percent increase in RPM revenues for the 2020/2021 RPM Base Residual Auction compared to what RPM revenues would have been using the 2019/2020 CETL value for ComEd.

Impact of Transmission Model Updates due to Termination of ConEd Wheel

PJM introduced updates to the PJM Region Transmission Planning Process in August 2017 that would have had a significant impact on the 2020/2021 RPM Base Residual Auction had the updates been incorporated into the determination of CETL values for the 2020/2021 RPM Base Residual Auction. The planning process updates stem from the termination of the ConEd Wheel Agreement. The updates include changes to the PJM NYISO PAR flows and additionally, PJM will no longer assume nonfirm import capacity from outside of PJM is available when determining the CETL values for MAAC, EMAAC, PSEG, and PSEG North. Table 27 shows the initial and final PJM CETL values for MAAC, EMAAC, PSEG, and PSEG North for the 2020/2021 BRA and the proposed CETL values.[101] The proposed CETL value for MAAC is 3,118 MW, which is 1,100 MW lower than the value used in the 2020/2021 BRA. The proposed CETL value for EMAAC is 8,300, a 500 MW decrease from the CETL value used in the 2020/2021 BRA. The proposed CETL value for PSEG is 6,474 MW, a 1,527 MW decrease from the CETL value used in the 2020/2021 BRA. The proposed CETL value for PSEG North is 2,955 MW, a 1,309 MW decrease from the CETL value used in the 2020/2021 BRA. Table 29 shows the results if PJM had used the new assumptions related to PJM NYISO PAR flows and nonfirm import capacity in the CETL studies for MAAC, EMAAC, PSEG, and PSEG North in the 2020/2021 RPM Base Residual Auction and everything else had remained the same. All binding constraints would have remained the same, except that the PSEG import limit would have been binding. The RTO clearing price would have decreased to $74.50 per MW-day, and the clearing quantity would have increased to 165,130.3 MW. The clearing quantity of seasonal capacity would have decreased to 388.6 MW. The MAAC clearing price would have increased to $90.56 per MW-day, and the clearing quantity would have increased to 66,790.0 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have remained the same at 90.6 MW. The EMAAC clearing price would have decreased to $182.29 per MW-day, and the clearing quantity would have increased to 30,144.7 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 0 MW. The PSEG clearing price would have increased to $302.93 per MW-day, and the clearing quantity would have increased to 5,645.1 MW. The clearing quantity of seasonal capacity for satisfying PSEG's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have remained the same at $188.12 per MW-day, and the clearing quantity would have remained the same at 23,960.3 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have remained the same at 148.9 MW. The DEOK clearing price would have remained the same at $130.00 per MW-day and the clearing quantity would have remained the same at 2,430.3 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 make whole MW, total RPM market revenues for the 2020/2021 RPM Base Residual Auction were $6,964,679,748. If PJM had used the new assumptions related to PJM NYISO PAR flows and nonfirm import capacity in the CETL studies for MAAC, EMAAC, PSEG, and PSEG North in the 2020/2021 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2020/2021 RPM Base Residual Auction would have been

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[101] See "M14B Updates," presented at August 10, 2017 meeting of Planning Committee.

$7,195,144,017, an increase of $230,464,269, or 3.3 percent, compared to the actual results. From another perspective, the ConEd Wheel Agreement and the associated modeling assumptions used in the CETL studies for MAAC, EMAAC, PSEG, PSEG North resulted in a 3.2 percent decrease in RPM revenues for the 2020/2021 RPM Base Residual Auction compared to what RPM revenues would have been had the updated modeling assumptions regarding PJM NYISO PAR flows and the availability of nonfirm import capacity been used in the determination of the 2020/2021 CTEL values for MAAC, EMAAC, PSEG, and PSEG North.

The impacts in PSEG were particularly significant. All available supply in the PSEG LDA cleared and the clearing price of $302.93 per MW-day was set by the intersection of the PSEG VRR curve and the vertical line extending upward from the last increment of cleared supply. Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the PSEG LDA for the 2020/2021 RPM Base Residual Auction were $349,528,002. If PJM had used the new assumptions related to PJM NYISO PAR flows and non-firm import capacity in the CETL studies for MAAC, EMAAC, PSEG, and PSEG North in the 2020/2021 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the PSEG LDA for the 2020/2021 RPM Base Residual Auction would have been $624,175,602, an increase of $274,647,600, or 78.6 percent, compared to the actual results. From another perspective, the ConEd Wheel Agreement and the associated modeling assumptions used in the CETL studies for MAAC, EMAAC, PSEG, PSEG North resulted in a 44.0 percent decrease in RPM revenues for the PSEG LDA for the 2020/2021 RPM Base Residual Auction compared to what RPM revenues would have been had the updated modeling assumptions regarding PJM NYISO PAR flows and the availability of nonfirm import capacity been used in the determination of the 2020/2021 CTEL values for MAAC, EMAAC, PSEG, and PSEG North

Impact of the Forecast Peak Load

The accuracy of the peak load forecast has a significant impact on RPM Base Residual Auction results. Table 45 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. For the five delivery years from 2013/2014 through 2017/2018, the peak load forecast for the Third IA has been on average 6.2 percent lower than the peak load forecast used in the corresponding BRA.

Table 30 shows the results if the peak load forecast had been reduced by 6.2 percent in the 2020/2021 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 $58.28 per MW-day, and the clearing quantity would have decreased to 154,571.1 MW. The amount of cleared seasonal capacity would have decreased to 388.6 MW. The MAAC clearing price would have decreased to $80.00 per MW-day, and the clearing quantity would have decreased to 61,528.5 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have remained the same at 90.6 MW. The EMAAC clearing price would have decreased to $134.29 per MW-day, and the clearing quantity would have decreased to 27,669.3 MW. The clearing quantity for seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have increased to $193.96 per MW-day, and the clearing quantity would have decreased to 22,244.9 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have remained the same at 148.9 MW. The DEOK clearing price would have remained the same at $130.00 per MW-day and the clearing quantity would have remained the same at 2,430.3 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 make whole MW, total RPM market revenues for the 2020/2021 RPM Base Residual Auction were $6,964,679,748. If the peak load forecast for the 2020/2021 RPM Base Residual Auction had been 6.2 percent lower and everything else had remained the same, total RPM market revenues for the 2020/2021 RPM Base Residual Auction would have been $5,489,678,329, a decrease of $1,475,001,419, or 21.2 percent, compared to the actual results. From another perspective, using PJM's peak load forecast for the 2020/2021 Base Residual Auction resulted in a 26.9 percent increase in RPM revenues for the 2020/2021 RPM Base Residual Auction compared to what revenues would have been using a load forecast that is 6.2 percent below the PJM peak load forecast. (Scenario 3)

Composition of the Steeply Sloped Portion of the Supply Curve

Table 31 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 resources were 6.2 percent of the offers greater than $35.00 per MW-day. Offers for coal fired units made up 35.0 percent of the offers greater than $35.00 per MW-day.

Demand Side Resources in RPM

There are two categories of demand side products included in the RPM market design for the 2020/2021 BRA:[102] [103]

[102] 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.

- **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 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.[104] The peak period definition for the EE Resource type is even more limited than Limited DR, including only the period from the hour ending 1500 and the hour ending 1800 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.[105]

Effective for the 2014/2015 through the 2017/2018 Delivery Years, there are three types of Demand Resource products included in the RPM market design:[106] [107]

- **Annual DR.** A Demand Resource that is required to be available on any day in the relevant delivery year for an unlimited number of interruptions. Annual DR is required to be capable of maintaining each interruption for only ten hours only during the hours of 10:00 a.m. to 10:00 p.m. EPT for the period May through October and 6:00 a.m. to 9:00 p.m. EPT for the period November through April unless there is an Office of the Interconnection approved maintenance outage during October through April.

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103 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.

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

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

106 134 FERC ¶ 61,066 (2011).

107 "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Article 1.

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

- **Limited DR.** Demand Resource that is required to be available on weekdays not including NERC holidays during the period of June through September in the relevant delivery year for up to 10 interruptions. Limited DR is required to be capable of maintaining each interruption for only six hours only during the hours of 12:00 p.m. to 8:00 p.m. EPT.

Effective for the 2018/2019 and the 2019/2020 Delivery Years, there are two types of Demand Resource and Energy Efficiency Resource products included in the RPM market design:[108] [109]

- **Base Capacity Resources**

  - **Base Capacity Demand Resources.** A Demand Resource that is required to be available on any day from June through September for an unlimited number of interruptions. Base Capacity DR is required to be capable of maintaining each interruption for at least ten hours only during the hours of 10:00 a.m. to 10:00 p.m. EPT.

  - **Base Capacity Energy Efficiency Resources.** A project designed to achieve a continuous (during summer peak periods) reduction in electric energy consumption that is not reflected in the peak load forecast for the delivery year for which the Base Capacity 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 Base Capacity Energy 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.

- **Capacity Performance Resources**

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108 151 FERC ¶ 61,208.

109 "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Article 1.

- **Annual Demand Resources.** A Demand Resource that is required to be available on any day in the relevant delivery year for an unlimited number of interruptions. Annual DR is required to be capable of maintaining each interruption for only ten hours only during the hours of 10:00 a.m. to 10:00 p.m. EPT for the period May through October and 6:00 a.m. to 9:00 p.m. EPT for the period November through April unless there is an Office of the Interconnection approved maintenance outage during October through April.

- **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 Energy Efficiency Resource type includes the period from the hour ending 15:00 EPT and the hour ending 18:00 EPT from June through August, and the period from the hour ending 8:00 EPT and the hour ending 9:00 EPT and the period from the hour ending 19:00 EPT and the hour ending 20:00 EPT from January through February, excluding weekends and federal holidays.

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

- **Annual Capacity Performance Resources**
  - **Annual Demand Resources**
  - **Annual Energy Efficiency Resources**
- **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.

Table 32 shows offered and cleared capacity from Demand Resources and Energy Efficiency Resources in the 2020/2021 RPM Base Residual Auction compared to the 2019/2020 RPM Base Residual Auction. Offers for DR decreased from 11,818.0 MW in the 2019/2020 BRA to 9,113.0 MW in the 2020/2021 BRA, a decrease of 2,705.0 MW or 22.9 percent. Offers for EE increased from 1,650.3 MW in the 2019/2020 BRA to 2,042.4 MW in the 2020/2021 BRA, an increase of 392.1 MW or 23.8 percent.

Impact of All DR and EE

Table 33 shows the results if there were no offers for DR or EE in the 2020/2021 RPM Base Residual Auction and everything else had remained the same. All binding constraints would have remained the same, except that the MAAC import limit would not have been binding. The RTO clearing price would have increased to $102.04 per MW-day, and the clearing quantity would have decreased to 161,737.1 MW. The clearing quantity of seasonal capacity would have decreased to 184.2 MW. The MAAC clearing price would have increased to $102.04 per MW-day, and the clearing quantity would have decreased to 65,112.9 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have decreased to 22.0 MW. The EMAAC clearing price would have increased to $192.11 per MW-day, and the clearing quantity would have decreased to 29,154.0 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have increased to $226.59 per MW-day, and the clearing quantity would have decreased to 22,923.6 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 $130.00 per MW-day, and the clearing quantity would have decreased to 2,338.7 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 make whole MW, total RPM market revenues for the 2020/2021 RPM Base Residual Auction were $6,964,679,748. If there were no offers for DR or EE in the 2020/2021 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2020/2021 RPM Base Residual Auction would have been $8,048,320,630, an increase of $1,083,640,882, or 15.6 percent, compared to the actual results. From another perspective, the inclusion of Demand Resources and Energy Efficiency resources resulted in a 13.5 percent reduction in RPM revenues for the 2020/2021 RPM Base Residual Auction compared to what RPM revenues would have been without any Demand Resources or Energy Efficiency resources.

Impact of All EE

Table 34 shows the results if there were no offers for EE and the EE add back had been removed in the 2020/2021 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 $74.50 per MW-day, and the clearing quantity would have decreased to 162,748.4 MW. The clearing quantity of seasonal resources would have decreased to 388.6 MW. The MAAC clearing price would have decreased to $85.00 per MW-day, and the clearing quantity would have decreased to 65,061.1 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have remained the same at 90.6 MW. The EMAAC clearing price would have decreased to $179.20 per MW-day, and the clearing quantity would have decreased to 29,267.6 MW. The clearing quantity of seasonal resources for satisfying EMAAC's reliability requirement would have remained the same at 0 MW. The ComEd clearing price decreased to $185.03 per MW-day, and the clearing quantity would have decreased to 23,146.6 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have remained the same at 148.9 MW. The DEOK clearing price remained the same at $130.00 per MW-day, and the clearing quantity would have decreased to 2,345.9 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 make whole MW, total RPM market revenues for the 2020/2021 RPM Base Residual Auction were $6,964,679,748. If there were no offers for EE and the EE add back MW were set to zero in the 2020/2021 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2020,2021 RPM Base Residual Auction would have been $6,673,183,027, a decrease of $291,496,721, or 4.2 percent, compared to the actual results. From another perspective, the inclusion of Energy Efficiency Resources resulted in a 4.4 percent increase in RPM revenues for the 2020/2021 RPM Base Residual Auction compared to what RPM revenues would have been without any Energy Efficiency Resources.

Impact of Annual DR and EE

Table 35 shows the results if there were no offers for Annual DR or EE in the 2020/2021 RPM Base Residual Auction and everything else had remained the same. All binding constraints would have remained the same, except that the MAAC import limit would not have been binding. The RTO clearing price would have increased to $100.00 per MW-day, and the clearing quantity would have decreased to 161,997.5 MW. The clearing quantity of seasonal capacity would have increased to 485.9 MW. The MAAC clearing price would have increased to $100.00 per MW-day, and the clearing quantity would have decreased to 65,246.7 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have increased to 111.6 MW. The EMAAC clearing price would have increased to $195.04 per MW-day, and the clearing quantity would have decreased to 29,233.5 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have increased to $216.80 per MW-day, and the clearing quantity would have decreased to 23,062.9 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have remained the same at 148.9 MW. The DEOK clearing price would have remained the same at $130.00 per MW-day, and the clearing quantity would have decreased to 2,338.7 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 make whole MW, total RPM market revenues for the 2020/2021 RPM Base Residual Auction were $6,964,679,748. If there were no offers for Annual DR or EE in the 2020/2021 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2020/2021 RPM Base Residual Auction would have been $7,937,273,776, an increase of $972,594,027, or 14.0 percent, compared to the actual results. From another perspective, the inclusion of Annual Demand Resources and Energy Efficiency resources resulted in a 12.3 percent reduction in RPM revenues for the 2020/2021 RPM Base Residual Auction compared to what RPM revenues would have been without any Annual Demand Resources or Energy Efficiency resources.

Impact of Seasonal DR and EE

Table 36 shows the results if there were no offers for Seasonal DR or EE in the 2020/2021 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 increased to $77.50 per MW-day, and the clearing quantity would have decreased to 164,928.5 MW. The clearing quantity of seasonal capacity would have decreased to 182.9 MW. The MAAC clearing price would have decreased to $86.03 per MW-day, and the clearing quantity would have decreased to 65,765.6 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have decreased to 50.9 MW. The EMAAC clearing price would have remained the same at $187.87 per MW-day, and the clearing quantity would have decreased to 29,595.6 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have decreased to $185.04 per MW-day, and the clearing quantity would have decreased to 23,803.9 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 $130.00 per MW-day, and the clearing quantity would have decreased to 2,427.4 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 make whole MW, total RPM market revenues for the 2020/2021 RPM Base Residual Auction were $6,964,679,748. If there were no offers for Seasonal DR or EE in the 2020/2021 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2020/2021 RPM Base Residual Auction would have been $6,951,735,280, a decrease of $12,944,468, or 0.2 percent, compared to the actual results. From another perspective, the inclusion of Seasonal Demand Resources and Energy Efficiency resources resulted in a 0.2 percent increase in RPM revenues for the 2020/2021 RPM Base Residual Auction compared to what RPM revenues would have been without any Seasonal Demand Resources or Energy Efficiency resources.

Impact of Seasonal Capacity

Table 37 shows the results if there were no offers for Seasonal products in the 2020/2021 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 increased to $79.00 per MW-day, and the clearing quantity would have decreased to 164,875.4 MW. The clearing quantity of seasonal capacity would have decreased to 0 MW. The MAAC clearing price would have increased to $86.30 per MW-day, and the clearing quantity would have decreased to 65,761.4 MW. The clearing quantity of seasonal capacity would have decreased to 0 MW. The EMAAC clearing price would have remained the same at $187.87 per MW-day, and the clearing quantity would have decreased to 29,595.6 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have decreased to $185.04 per MW-day, and the clearing quantity would have decreased to 23,803.9 MW. The clearing quantity of seasonal capacity would have decreased to 0 MW. The DEOK clearing price would have remained the same at $130.00 per MW-day, and the clearing quantity would have decreased to 2,427.4 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 make whole MW, total RPM market revenues for the 2020/2021 RPM Base Residual Auction were $6,964,679,748. If there were no offers for Seasonal products in the 2020/2021 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2020/2021 RPM Base Residual Auction would have been $6,993,615,290, an increase of $28,935,542, or 0.4 percent, compared to the actual results. From another perspective, the inclusion of Seasonal resources resulted in a 0.4 percent decrease in RPM revenues for the 2020/2021 RPM Base Residual Auction compared to what RPM revenues would have been without any seasonal resources.

Impact of DR, EE, and Seasonal Capacity

Table 38 shows the results if there were no offers for Seasonal products as well as no offers for Annual DR or EE in the 2020/2021 RPM Base Residual Auction and everything else had remained the same. All binding constraints would have remained the same, except that the MAAC import limit would not have been binding. The RTO clearing price would have increased to $104.30 per MW-day, and the clearing quantity would have decreased to 161,689.2 MW. The clearing quantity of seasonal capacity would have decreased to 0 MW. The MAAC clearing price would have increased to $104.30 per MW-day, and the clearing quantity would have decreased to 65,613.1 MW. The clearing quantity of seasonal capacity would have decreased to 0 MW. The EMAAC clearing price would have increased to $192.11 per MW-day, and the clearing quantity would have decreased to 29,154.0 MW. The clearing quantity of seasonal capacity would have remained the same at 0 MW. The ComEd clearing price would have increased to $226.59 per MW-day, and the clearing quantity would have decreased to 22,923.6 MW. The clearing quantity of seasonal capacity would have decreased to 0 MW. The DEOK clearing price would have remained the same at $130.00 per MW-day, and the clearing quantity would have decreased to 2,338.7 MW. The clearing quantity of seasonal capacity would have remained the same at 0 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2020/2021 RPM Base Residual Auction were $6,964,679,748. If there were no offers for Seasonal products or demand side products in the 2020/2021 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2020/2021 RPM Base Residual Auction would have been $8,134,983,164, an increase of $1,170,303,415, or 16.8 percent, compared to the actual results. From another perspective, the inclusion of Seasonal resources, and DR and EE resources resulted in a 14.4 percent decrease in RPM revenues for the 2020/2021 RPM Base Residual Auction compared to what RPM revenues would have been without any Seasonal, DR, or EE resources.

Impact of Winter Resources

Table 39 shows the results if offers from winter resources were reduced by 50 percent in the 2020/2021 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 increased to $84.00 per MW-day, and the clearing quantity would have decreased to 164,763.3 MW. The clearing quantity of seasonal capacity would have decreased to 200.0 MW. The MAAC clearing price would have increased to $86.30 per MW-day, and the clearing quantity would have decreased to 65,762.4 MW. The clearing quantity of seasonal capacity for satisfying MAAC’s reliability requirement would have decreased to 45.7 MW. The EMAAC clearing price would have remained the same at $187.87 per MW-day, and the clearing quantity would have decreased to 29,595.6 MW. The clearing quantity of seasonal capacity for satisfying EMAAC’s reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have decreased to $170.02 per MW-day, and the clearing quantity would have decreased to 22,961.4 MW. The clearing quantity of seasonal capacity for satisfying ComEd’s reliability requirement would have decreased to 74.6 MW. The DEOK clearing price would have remained the same at $130.00 per MW-day, and the clearing quantity would have remained the same at 2,430.3 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 make whole MW, total RPM market revenues for the 2020/2021 RPM Base Residual Auction were $6,964,679,748. If offers from Winter resources were reduced by 50 percent in the 2020/2021 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2020/2021 RPM Base Residual Auction would have been $6,970,014,319, an increase of $5,334,571, or 0.1 percent, compared to the actual results. From another perspective, the inclusion of all offers from winter resources resulted in a 0.1 percent reduction in RPM revenues for the 2020/2021 RPM Base Residual Auction compared to what RPM revenues would have been if offers from winter resources had been reduced by 50 percent.

Impact of Seasonal Matching Across LDAs

Table 40 shows the results if Seasonal offers were only matched with complementary Seasonal offers within the same LDA in the 2020/2021 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 increased to $77.50 per MW-day, and the clearing quantity would have increased to 165,122.9 MW. The clearing quantity of seasonal capacity would have decreased to 363.4 MW. The MAAC clearing price would have increased to $86.30 per MW-day, and the clearing quantity would have decreased to 65,795.6 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have decreased to 65.4 MW. Unlike the clearing in the BRA, all the matching seasonal offers are located within the MAAC LDA. The EMAAC clearing price would have remained the same at $187.87 per MW-day, and the clearing quantity would have decreased to 29,595.6 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have remained the same at $188.12 per MW-day, and the clearing quantity would have remained the same at 23,960.3 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have remained the same at 148.9 MW. The DEOK clearing price would have remained the same at $130.00 per MW-day, and the clearing quantity would have remained the same at 2,430.3 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 make whole MW, total RPM market revenues for the 2020/2021 RPM Base Residual Auction were $6,964,679,748. If Seasonal offers were only matched with complementary Seasonal offers within the same LDA in the 2020/2021 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2020/2021 RPM Base Residual Auction would have been $6,993,516,300, an increase of $28,836,552, or 0.4 percent, compared to the actual results. From another perspective, allowing Seasonal offers to be matched with complementary Seasonal offers from any LDA resulted in a 0.4 percent reduction in RPM revenues for the 2020/2021 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.

Capacity Imports

Generation external to the PJM region is eligible to be offered into an RPM auction if it meets specific requirements.[110] [111] 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; 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 market.[112]

Planned External Generation Capacity Resources are eligible to be offered into an RPM Auction if they meet specific requirements.[113] [114] Planned External Generation Capacity Resources are proposed Generation Capacity Resources, or a proposed increase in the

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

111 "PJM Manual 18: PJM Capacity Market," Rev. 37 (April 27, 2017) at 54-55 & 81.

112 OATT, Schedule 1, Section 1.10.1A.

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

114 "PJM Manual 18: PJM Capacity Market," Re 37 (April 27, 2017) at 57-58.

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.[115] 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.[116]

Effective with the 2017/2018 Delivery Year, Capacity Import Limits (CILs) are established for each of the five external source zones and the overall PJM region to account for the risk that external generation resources may not be able to deliver energy during the relevant Delivery Year due to the curtailment of firm transmission by third parties.[117] Capacity Market Sellers may request an exception to the CIL for an external generation resource by committing that the resource will be pseudo tied prior to the start of the relevant Delivery Year, by demonstrating that it has long-term firm transmission service confirmed on the complete transmission path from the resource to PJM, and by agreeing to be subject to the same RPM must offer requirement as internal PJM generation resources.

Effective June 9, 2015, an external Generation Capacity Resource must obtain an exception to the CIL to be eligible to offer as a Capacity Performance Resource.[118]

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.

Impact of Imports

Reduction by 25 Percent

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[115] 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).

[116] 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).

[117] 147 FERC ¶ 61,060 (2014).

[118] 151 FERC ¶ 61,208 (2015).

Table 41 shows the results if import offers for external generation resources in the 2020/2021 RPM Base Residual Auction had been reduced by 25 percent and everything else had remained the same. All binding constraints would have remained the same. The RTO clearing price would have increased to $85.44 per MW-day, and the clearing quantity would have decreased to 164,925.2 MW. The clearing quantity of seasonal capacity would have remained the same at 397.9 MW. The MAAC clearing price would have decreased to $85.73 per MW-day, and the clearing quantity would have decreased to 65,805.2 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have remained the same at 90.6 MW. The EMAAC clearing price would have remained the same at $187.87 per MW-day, and the clearing quantity would have decreased to 29,595.6 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have decreased to $170.02 per MW-day, and the clearing quantity would have decreased to 22,961.4 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have remained the same at 148.9 MW. The DEOK clearing price would have remained the same at $130.00 per MW-day, and the clearing quantity would have remained the same at 2,430.3 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 make whole MW, total RPM market revenues for the 2020/2021 RPM Base Residual Auction were $6,964,679,748. If offers for external generation were reduced by 25 percent and everything else had remained the same, total RPM market revenues for the 2020/2021 RPM Base Residual Auction would have been $7,010,987,176, an increase of $46,307,427, or 0.7 percent, compared to the actual results. From another perspective, the inclusion of all offers for external generation resources resulted in a 0.7 percent reduction in RPM revenues for the 2020/2021 RPM Base Residual Auction compared to what RPM revenues would have been if offers for external generation had been reduced by 25 percent.[119]

Reduction by 75 Percent

Table 41 shows the results if import offers for external generation resources in the 2020/2021 RPM Base Residual Auction had been reduced by 75 percent and everything else had remained the same. All binding constraints would have remained the same, except that the MAAC import limit would not have been binding. The RTO clearing price would have increased to $95.56 per MW-day, and the clearing quantity would have decreased to 164,552.6 MW. The clearing quantity of seasonal capacity would have

119 This analysis does not account for the fact that reduced imports could have a positive impact on CETL and an associated impact on clearing prices.

increased to 464.9 MW. The MAAC clearing price would have increased to $95.56 per MW-day, and the clearing quantity would have increased to 66,658.9 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have remained the same at 90.6 MW. The EMAAC clearing price would have remained the same at $187.87 per MW-day, and the clearing quantity would have decreased to 29,595.6 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have decreased to $170.02 per MW-day, and the clearing quantity would have decreased to 22,961.4 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have remained the same at 148.9 MW. The DEOK clearing price would have remained the same at $130.00 per MW-day, and the clearing quantity for satisfying DEOK's reliability requirement would have remained the same at 2,430.3 MW. The clearing quantity of seasonal capacity would have remained the same at 0 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2020/2021 RPM Base Residual Auction were $6,964,679,748. If offers for external generation were reduced by 75 percent and everything else had remained the same, total RPM market revenues for the 2020/2021 RPM Base Residual Auction would have been $7,401,236,623, an increase of $436,556,875, or 6.3 percent, compared to the actual results. From another perspective, the inclusion of all offers for external generation resources resulted in a 5.9 percent reduction in RPM revenues for the 2020/2021 RPM Base Residual Auction compared to what RPM revenues would have been if offers for external generation had been reduced by 75 percent.

Impact of All DR, Seasonal Resources, and Capacity Imports

Table 42 shows the results if import offers for external generation resources had been reduced by 75 percent, there were no offers for DR or EE and no Seasonal resources in the 2020/2021 RPM Base Residual Auction and everything else had remained the same. All binding constraints would have remained the same, except that the MAAC and DEOK import constraints would not have been binding. The RTO clearing price would have increased to $130.77 per MW-day, and the clearing quantity would have decreased to 160,748.5 MW. The clearing quantity of seasonal capacity would have decreased to 0 MW. The MAAC clearing price would have increased to $130.77 per MW-day, and the clearing quantity would have increased to 66,853.5 MW. The clearing quantity of seasonal capacity would have decreased to 0 MW. The EMAAC clearing price would have increased to $192.11 per MW-day, and the clearing quantity would have decreased to 29,154.0 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have increased to $226.59 per MW-day, and the clearing quantity would have decreased to 22,923.6 MW. The clearing quantity of seasonal capacity would have decreased to 0 MW. The DEOK clearing price would have increased to $130.77 per MW-day, and the clearing quantity would have decreased to 2,338.7 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 make whole MW, total RPM market revenues for the 2020/2021 RPM Base Residual Auction were $6,964,679,748. If offers for external generation were reduced by 75 percent and there were no offers for DR or EE and no Seasonal resources, and everything else had remained the same, total RPM market revenues for the 2020/2021 RPM Base Residual Auction would have been $9,127,165,743, an increase of $2,162,485,995, or 31.0 percent, compared to the actual results. From another perspective, the inclusion of all offers for external generation resources, and DR, EE, and Seasonal resources resulted in a 23.7 percent reduction in RPM revenues for the 2020/2021 RPM Base Residual Auction compared to what RPM revenues would have been if offers for external generation had been reduced by 75 percent and there were no offers for DR or EE and no Seasonal resources.

Impact of Inconsistency Between EE Cleared MW and EE Add Back MW

Under the new EE add back MW rules, if the ratio of the EE add back MW to cleared EE MW in the BRA exceeds the predetermined threshold, then PJM adjusts the EE add back MW and reruns the auction clearing a second and final time. For the 2020/2021 RPM Base Residual Auction, the ratio in the initial solution exceeded the threshold ratio of 1.422519856. Adjustments were made to the EE add back MW which in effect reduced the demand by shifting the VRR curve to the left. The auction was cleared for a second and final time with the new VRR curve. However, even with the reduction in the EE add back amount, the demand curve was still shifted by an amount greater than the quantity of cleared EE that shifted supply, so the clearing prices were affected by how the EE add back MW mechanism was implemented. Table 43 shows the results if adjustments to the EE add back MW had been made such that for each LDA the EE cleared MW were equal to the EE add back MW in the 2020/2021 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 $74.75 per MW-day, and the clearing quantity would have decreased to 164,429.0 MW. The clearing quantity of Seasonal capacity would have decreased to 388.6 MW. The MAAC clearing price would have decreased to $85.00 per MW-day, and the clearing quantity would have decreased to 65,574.1 MW. The clearing quantity of Seasonal capacity for satisfying MAAC's reliability requirement would have remained the same at 90.6 MW. The EMAAC clearing price would have decreased to $179.20 per MW-day, and the clearing quantity would have decreased to 29,551.8 MW. The clearing quantity of Seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have increased to $190.30 per MW-day, and the clearing quantity would have decreased to 23,848.0 MW. The clearing quantity of Seasonal capacity for satisfying ComEd's reliability requirement would have remained the same at 148.9 MW. The DEOK clearing price would have remained the same at

$130.00 per MW-day, and the clearing quantity would have decreased to 2,411.2 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 make whole MW, total RPM market revenues for the 2020/2021 RPM Base Residual Auction were $6,964,679,748. If adjustments to the EE add back MW had been made such that for each LDA the EE cleared MW were equal to the EE add back MW in the 2020/2021 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2020/2021 RPM Base Residual Auction would have been $6,802,281,900, a decrease of $162,397,848, or 2.3 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 add back MW, resulted in a 2.4 percent increase in RPM revenues for the 2020/2021 RPM Base Residual Auction compared to what RPM revenues would have been if the EE add back MW were equal to the EE cleared MW for each LDA.

Impact of Price Responsive Demand (PRD)

Table 44 shows the results if there were no offers for PRD in the 2020/2021 RPM Base Residual Auction and everything else had remained the same. All binding constraints would have remained the same except that the BGE import constraint would have been binding. The RTO clearing price would have increased to $77.58 per MW-day, and the clearing quantity would have increased to 165,701.6 MW. The clearing quantity of seasonal capacity would have remained the same at 397.9 MW. The MAAC clearing price would have increased to $91.29 per MW-day, and the clearing quantity would have increased to 66,342.2 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have remained the same at 90.6 MW. The EMAAC clearing price would have remained the same at $187.87 per MW-day, and the clearing quantity would have increased to 29,658.8 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 increased to $114.99 per MW-day, and the clearing quantity would have increased to 2,314.9 MW. The clearing quantity of seasonal capacity would have remained the same at 0 MW. The ComEd clearing price would have remained the same at $188.12 per MW-day, and the clearing quantity would have remained the same at 23,960.3 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have remained the same at 148.9 MW. The DEOK clearing price would have remained the same at $130.00 per MW-day, and the clearing quantity would have remained the same at 2,430.3 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 make whole MW, total RPM market revenues for the 2020/2021 RPM Base Residual Auction were $6,964,679,748. If there were no offers for PRD in the 2020/2021 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2020/2021 RPM Base Residual Auction would have been $7,103,194,078, an increase of $138,514,329, or 2.0 percent, compared to the actual results. From another perspective, the inclusion of PRD resulted in a 2.0 percent reduction in RPM revenues for the 2020/2021 RPM Base Residual Auction compared to what RPM revenues would have been without any PRD.

PJM modeled PRD as offers from a supply side resource rather than incorporating the PRD offers into the VRR curve. There was no impact on market results.

Tables and Figures for RTO Market

Table 12 RTO offer statistics: 2020/2021 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	195,836.7	186,726.1		
DR capacity	10,673.0	11,624.2		
EE capacity	2,184.8	2,378.1		
Generation winter capacity	409.2	409.2		
Total internal RTO capacity	209,103.7	201,137.6		
FRR	(14,749.1)	(13,804.9)		
Imports	5,929.5	5,390.7		
RPM capacity	200,284.1	192,723.4		
Exports	(1,319.8)	(1,293.3)		
FRR optional	0.0	0.0		
Excused Existing Generation Capacity Resources	(4,251.0)	(3,263.4)		
Unoffered Planned Generation Capacity Resources	(1,065.8)	(1,021.0)		
Unoffered Intermittent Resources	(1,948.5)	(1,889.0)		
Unoffered Capacity Storage Resources	(681.4)	(668.4)		
Unoffered generation winter capacity	(17.7)	(17.7)		
Unoffered DR and EE	(2,278.3)	(2,489.3)		
Available	188,721.5	182,081.2	100.0%	100.0%
Generation offered	178,470.6	170,925.8	94.6%	93.9%
DR offered	8,373.2	9,113.0	4.4%	5.0%
EE offered	1,877.7	2,042.4	1.0%	1.1%
Total offered	188,721.5	182,081.2	100.0%	100.0%
Unoffered Existing Generation Capacity Resources	0.0	0.0	0.0%	0.0%

Table 13 Reserve margin: 2020/2021 RPM Base Residual Auction

	Reserve Margin Calculation
Forecast peak load	153,915.0
FRR peak load	12,200.6
PRD	558.0
IRM	16.6%
Pool-wide average EFORd	6.59%
Cleared UCAP (generation and DR)	163,399.0
Cleared ICAP (generation and DR)	174,926.7
RPM peak load	141,156.4
Reserve margin	23.9%
Reserve cleared in excess of IRM	7.3%

Table 14 Net excess: 2020/2021 RPM Base Residual Auction

	UCAP (MW)				
	RTO	MAAC	EMAAC	ComEd	DEOK
Cleared generation and DR plus make whole	163,399.0	65,272.9	29,315.1	23,258.4	2,364.5
CETL	NA	4,218.0	8,800.0	4,064.0	5,072.0
Reliability requirement adjusted for FRR	154,355.3	66,385.0	36,921.0	26,224.0	7,102.3
Net excess/(deficit)	9,043.7	3,105.9	1,194.1	1,098.4	334.2

Table 15 Net load prices: 2020/2021 RPM Base Residual Auction

	$ per MW-day				
	RTO	MAAC	EMAAC	ComEd	DEOK
Resource clearing price	$76.53	$86.04	$187.87	$188.12	$130.00
Preliminary zonal capacity price	$76.53	$86.05	$187.77	$188.13	$130.00
Adjusted preliminary zonal capacity price	$76.83	$86.52	$188.41	$188.43	$130.30
Base zonal CTR credit rate	$0.00	($0.11)	$13.56	$5.29	$26.91
Preliminary net load price	$76.83	$86.63	$174.85	$183.14	$103.39

Table 16 Capacity modifications (ICAP): 2020/2021 RPM Base Residual Auction[120]

	ICAP (MW)				
	RTO	MAAC	EMAAC	ComEd	DEOK
Generation increases	4,257.5	1,367.1	274.9	9.4	4.0
Generation decreases	(3,623.8)	(2,976.2)	(2,876.4)	(20.8)	(0.6)
Capacity modifications net increase/(decrease)	633.7	(1,609.1)	(2,601.5)	(11.4)	3.4
DR increases	1,964.1	282.5	163.8	435.0	115.3
DR decreases	(4,015.0)	(1,392.9)	(585.0)	(409.9)	(21.1)
DR net increase/(decrease)	(2,050.9)	(1,110.4)	(421.2)	25.1	94.2
EE increases	1,257.4	488.7	250.5	253.9	47.9
EE decreases	(673.0)	(271.7)	(113.9)	(169.3)	(1.2)
EE modifications increase/(decrease)	584.4	217.0	136.6	84.6	46.7
Net internal capacity increase/(decrease)	(832.8)	(2,502.5)	(2,886.1)	98.3	144.3

Table 17 Capacity modifications (UCAP): 2020/2021 RPM Base Residual Auction

	UCAP (MW)				
	RTO	MAAC	EMAAC	ComEd	DEOK
Generation increases	4,171.9	1,356.2	266.3	9.4	3.4
Generation decreases	(2,953.2)	(2,326.5)	(2,238.6)	(21.6)	(1.6)
Capacity modifications net increase/(decrease)	1,218.7	(970.3)	(1,972.3)	(12.2)	1.8
DR increases	2,136.7	307.1	178.0	473.3	125.5
DR decreases	(4,368.1)	(1,515.0)	(636.4)	(446.0)	(23.1)
DR net increase/(decrease)	(2,231.4)	(1,207.9)	(458.4)	27.3	102.4
EE increases	1,368.0	531.3	272.3	276.3	52.2
EE decreases	(731.4)	(295.2)	(123.6)	(184.3)	(1.3)
EE modifications increase/(decrease)	636.6	236.1	148.7	92.0	50.9
Net capacity/DR/EE modifications increase/(decrease)	(376.1)	(1,942.1)	(2,282.0)	107.1	155.1
EFORd effect	1,027.6	599.1	(46.1)	329.8	44.3
DR and EE effect	11.4	3.5	1.4	2.8	0.0
Net internal capacity increase/(decrease)	662.9	(1,339.5)	(2,326.7)	439.7	199.4

120 Only cap mods that had a start date on or before June 1, 2020 and DR and EE plans for the 2020/2021 RPM Base Residual Auction are included.

Table 18 Winter capacity modifications (ICAP): 2020/2021 RPM Base Residual Auction

	ICAP (MW)				
	RTO	MAAC	EMAAC	ComEd	DEOK
Generation increases	825.2	109.2	0.0	248.7	0.0
Generation decreases	0.0	0.0	0.0	0.0	0.0
Capacity modifications net increase/(decrease)	825.2	109.2	0.0	248.7	0.0
DR increases	0.0	0.0	0.0	0.0	0.0
DR decreases	0.0	0.0	0.0	0.0	0.0
DR net increase/(decrease)	0.0	0.0	0.0	0.0	0.0
EE increases	0.0	0.0	0.0	0.0	0.0
EE decreases	0.0	0.0	0.0	0.0	0.0
EE modifications increase/(decrease)	0.0	0.0	0.0	0.0	0.0
Net internal capacity increase/(decrease)	825.2	109.2	0.0	248.7	0.0

Table 19 Winter capacity modifications (UCAP): 2020/2021 RPM Base Residual Auction

	UCAP (MW)				
	RTO	MAAC	EMAAC	ComEd	DEOK
Generation increases	825.2	109.2	0.0	248.7	0.0
Generation decreases	0.0	0.0	0.0	0.0	0.0
Capacity modifications net increase/(decrease)	825.2	109.2	0.0	248.7	0.0
DR increases	0.0	0.0	0.0	0.0	0.0
DR decreases	0.0	0.0	0.0	0.0	0.0
DR net increase/(decrease)	0.0	0.0	0.0	0.0	0.0
EE increases	0.0	0.0	0.0	0.0	0.0
EE decreases	0.0	0.0	0.0	0.0	0.0
EE modifications increase/(decrease)	0.0	0.0	0.0	0.0	0.0
Net capacity/DR/EE modifications increase/(decrease)	825.2	109.2	0.0	248.7	0.0
EFORd effect	0.0	0.0	0.0	0.0	0.0
DR and EE effect	0.0	0.0	0.0	0.0	0.0
Net internal capacity increase/(decrease)	825.2	109.2	0.0	248.7	0.0

Table 20 Offered and cleared capacity by LDA, resource type, and season type: 2020/2021 RPM Base Residual Auction

		Offered UCAP (MW)			Cleared UCAP (MW)		
LDA	Resource Type	Annual	Summer	Winter	Annual	Summer	Winter
RTO	GEN	170,591.7	93.1	241.0	155,572.4	3.1	197.3
RTO	DR	8,367.2	745.8	0.0	7,531.5	145.6	0.0
RTO	EE	1,839.0	203.4	0.0	1,607.4	51.8	0.0
MAAC	GEN	68,597.0	47.0	55.3	62,706.5	0.0	44.9
MAAC	DR	2,652.7	401.7	0.0	2,512.3	94.1	0.0
MAAC	EE	559.3	81.7	0.0	508.5	18.4	0.0
EMAAC	GEN	29,316.8	28.6	0.0	28,267.9	0.0	0.0
EMAAC	DR	1,056.2	137.1	0.0	1,056.1	29.6	0.0
EMAAC	EE	284.2	29.8	0.0	284.2	4.5	0.0
ComEd	GEN	24,685.4	0.0	73.8	21,745.5	0.0	73.8
ComEd	DR	1,437.4	180.0	0.0	1,425.9	43.9	0.0
ComEd	EE	640.0	84.7	0.0	640.0	31.2	0.0
DEOK	GEN	2,898.5	0.0	0.0	2,226.5	0.0	0.0
DEOK	DR	139.2	31.1	0.0	138.5	7.2	0.0
DEOK	EE	65.3	1.1	0.0	65.3	0.3	0.0

Table 21 Weighted average sell offer prices by LDA, resource type, and season type: 2020/2021 RPM Base Residual Auction

		Weighted-Average ($ per MW-day UCAP)		
LDA	Resource Type	Annual	Summer	Winter
RTO	GEN	$41.90	$50.28	$67.77
RTO	DR	$44.07	$26.96	
RTO	EE	$32.76	$5.09	
MAAC	GEN	$48.45	$68.90	$73.79
MAAC	DR	$48.87	$15.30	
MAAC	EE	$45.57	$3.90	
EMAAC	GEN	$50.98	$67.41	
EMAAC	DR	$52.15	$20.34	
EMAAC	EE	$63.58	$8.27	
ComEd	GEN	$68.09		$47.71
ComEd	DR	$48.30	$29.38	
ComEd	EE	$5.30	$0.03	
DEOK	GEN	$76.60		
DEOK	DR	$29.35	$5.74	
DEOK	EE	$29.63	$1.90	

Table 22 Offered capacity by resource type, season type and price range as percent of net CONE times B: 2020/2021 RPM Base Residual Auction[121]

	Offered UCAP (MW)								
	Annual			Summer			Winter		
Resource Type	0 Percent	0 to 50 Percent	50 to > 100 Percent	0 Percent	0 to 50 Percent	50 to > 100 Percent	0 Percent	0 to 50 Percent	50 to > 100 Percent
GEN	42,362.6	106,638.1	21,591.0	10.0	79.4	3.7	55.3	109.9	75.7
DR	584.2	7,171.5	611.5	445.4	226.9	73.5	0.0	0.0	0.0
EE	893.6	795.0	150.4	150.5	52.5	0.4	0.0	0.0	0.0

Table 23 Cleared MW by zone and resource type/fuel source: 2020/2021 RPM Base Residual Auction[122]

	Cleared UCAP (MW)										
Zone	DR	EE	Coal	Gas	Hydroelectric	Nuclear	Oil	Solar	Solid Waste	Wind	Total
AECO	62.4	26.8	452.5	1,231.8	0.0	0.0	22.9	6.1	0.0	0.0	1,802.5
AEP	1,010.4	109.6	5,946.7	9,142.9	49.2	201.8	0.0	0.0	43.3	140.5	16,644.4
AP	709.8	36.4	4,737.8	3,327.4	114.0	0.0	0.0	0.4	0.0	64.8	8,990.6
ATSI	688.6	32.5	2,954.3	3,842.2	0.0	2,043.0	365.3	0.0	0.0	0.0	9,925.9
BGE	211.0	119.1	1,227.1	223.1	0.0	1,682.0	503.7	0.0	55.1	0.0	4,021.1
ComEd	1,469.8	671.2	4,148.8	9,044.5	0.0	8,065.7	224.3	0.0	0.0	336.0	23,960.3
DAY	164.5	32.9	0.0	1,298.1	0.0	0.0	32.0	0.1	0.0	0.0	1,527.6
DEOK	145.7	65.6	1,562.6	525.5	105.4	0.0	33.0	0.0	0.0	0.0	2,437.8
DLCO	159.9	12.3	129.5	168.6	0.0	1,796.5	9.0	0.0	0.0	0.0	2,275.8
Dominion	585.3	168.9	4,075.7	13,112.8	3,066.3	3,471.4	1,714.6	63.7	217.4	45.5	26,521.6
DPL	190.3	45.6	394.4	4,161.7	0.0	0.0	601.9	4.9	0.0	0.0	5,398.8
EKPC	136.9	3.0	1,638.7	1,047.8	117.0	0.0	0.0	0.0	0.0	0.0	2,943.4
External	0.0	0.0	2,649.3	660.2	590.1	97.6	0.0	0.0	0.0	0.0	3,997.2
JCPL	142.2	47.4	0.0	2,909.8	316.6	0.0	91.9	34.1	9.1	0.0	3,551.0
Met-Ed	241.8	14.4	111.2	2,457.0	14.5	0.0	298.3	0.0	73.7	0.0	3,210.9
PECO	361.2	70.8	0.0	4,090.8	807.0	4,658.9	788.1	0.0	87.5	0.0	10,864.3
PENELEC	304.1	10.1	5,031.5	2,168.4	505.4	0.0	58.0	0.0	40.4	84.5	8,202.3
Pepco	183.9	60.8	2,156.2	3,698.8	0.0	0.0	261.3	0.0	49.0	0.0	6,410.0
PPL	579.9	34.0	3,128.3	7,532.5	594.7	2,457.1	39.0	1.0	8.7	23.1	14,398.2
PSEG	325.9	92.8	0.0	4,502.5	1.5	2,917.0	0.0	11.9	165.0	0.0	8,016.6
RECO	3.7	5.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.1
Total	7,677.1	1,659.2	40,344.6	75,146.4	6,281.7	27,391.0	5,043.3	122.2	749.2	694.4	165,109.2

121 Data aggregated based on PJM confidentiality rules.

122 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, 2,917.0 MW of the 8,016.6 cleared MW in the PSEG Zone were modeled and cleared in the EMAAC LDA.

Table 24 Uncleared generation offers by technology type and age: 2020/2021 RPM Base Residual Auction[123] [124]

	Uncleared UCAP (MW)		
Technology Type	Less Than or Equal to 40 Years Old	Greater than 40 Years Old	Total
Coal Fired	2,296.9	5,310.2	7,607.1
Combined cycle	1,720.9	90.2	1,811.1
Combustion turbine	1,092.9	777.7	1,870.6
Oil or gas steam	175.4	409.5	584.9
Other	1,058.5	2,220.7	3,279.2
Total	6,344.6	8,808.3	15,152.9

Table 25 Uncleared generation resources in multiple auctions[125] [126]

	2020/2021		2019/2020 Results for Same Set of Resources		2018/2019 Results for Same Set of Resources	
Technology	Uncleared UCAP (MW)	Number of Resources	Uncleared UCAP (MW)	Number of Resources	Uncleared UCAP (MW)	Number of Resources
Coal Fired	7,607.1	73	3,964.4	44	1,124.6	36
Combined cycle	1,811.1	58	429.3	20	293.3	17
Combustion turbine	1,870.6	163	970.5	65	620.8	51
Other	3,864.1	94	3,600.4	23	1,704.2	9
Total	15,152.9	388	8,964.6	152	3,742.9	113

123 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 2020/2021 BRA, waste coal resources are included in the coal fired category.

124 Data aggregated based on PJM confidentiality rules.

125 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 2020/2021 BRA, waste coal resources are included in the coal fired category.

126 Data aggregated based on PJM confidentiality rules.

Table 26 PJM LDA CETL and CETO values: 2019/2020 and 2020/2021 RPM Base Residual Auctions

	2019/2020			2020/2021			Change			
			CETL to CETO			CETL to CETO	CETO		CETL	
LDA	CETO	CETL	Ratio	CETO	CETL	Ratio	MW	Percent	MW	Percent
MAAC	(6,930.0)	7,385.0	(107%)	(7,000.0)	4,218.0	(60%)	(70.0)	1%	(3,167.0)	(43%)
EMAAC	1,580.0	8,856.0	561%	3,650.0	8,800.0	241%	2,070.0	131%	(56.0)	(1%)
SWMAAC	3,920.0	9,400.0	240%	2,900.0	9,802.0	338%	(1,020.0)	(26%)	402.0	4%
PSEG	5,590.0	7,856.0	141%	5,900.0	8,001.0	136%	310.0	6%	145.0	2%
PSEG North	2,280.0	3,827.0	168%	2,620.0	4,264.0	163%	340.0	15%	437.0	11%
DPL South	1,230.0	1,898.0	154%	1,230.0	1,872.0	152%	0.0	0%	(26.0)	(1%)
Pepco	2,870.0	6,985.0	243%	1,540.0	7,625.0	495%	(1,330.0)	(46%)	640.0	9%
ATSI	4,490.0	9,212.0	205%	4,660.0	9,889.0	212%	170.0	4%	677.0	7%
ATSI Cleveland	3,390.0	5,501.0	162%	3,540.0	5,605.0	158%	150.0	4%	104.0	2%
ComEd	610.0	5,160.0	846%	640.0	4,064.0	635%	30.0	5%	(1,096.0)	(21%)
BGE	4,060.0	6,234.7	154%	4,410.0	6,244.0	142%	350.0	9%	9.3	0%
PPL	(170.0)	6,168.0	(3,628%)	(1,010.0)	7,084.0	(701%)	(840.0)	494%	916.0	15%
DAY	NA	NA	NA	2,550.0	3,401.0	NA	NA	NA	NA	NA
DEOK	NA	NA	NA	3,650.0	5,072.0	NA	NA	NA	NA	NA

Table 27 Changes to PJM LDA CETL values

LDA	Initial CETL Values 2020/2021 BRA	Final CETL Values 2020/2021 BRA	Proposed CETL Values
MAAC	7,199	4,218	3,118
EMAAC	10,968	8,800	8,300
SWMAAC	9,747	9,802	
PSEG	8,497	8,001	6,474
PSEG North	4,881	4,264	2,955
DPL South	1,850	1,872	
PEPCO	7,625	7,625	
ATSI	9,814	9,889	
ATSI-Cleveland	5,605	5,605	
ComEd	4,234	4,064	
BGE	6,246	6,244	
PPL	7,226	7,084	
DAY	1,834	3,401	
DEOK	4,907	5,072	

Table 28 Impact of ComEd CETL change: 2020/2021 RPM Base Residual Auction

Scenario 1

		Actual Auction Results		ComEd CETL	
LDA	Season	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$76.53	164,711.3	$80.76	164,556.7
	Summer	$76.53	397.9	$80.76	397.9
	Winter	$76.53	397.9	$80.76	397.9
RTO Total			165,109.2		164,954.6
MAAC	Annual	$86.04	65,727.3	$85.22	65,707.1
	Summer	$86.04	223.2	$85.22	246.7
	Winter	$86.04	90.6	$85.22	90.6
MAAC Total			65,817.9		65,797.7
EMAAC	Annual	$187.87	29,608.2	$187.87	29,594.9
	Summer	$187.87	67.6	$187.87	15.1
	Winter	$187.87	0.0	$187.87	0.0
EMAAC Total			29,608.2		29,594.9
ComEd	Annual	$188.12	23,811.4	$170.02	22,812.5
	Summer	$188.12	148.9	$170.02	148.9
	Winter	$188.12	148.9	$170.02	148.9
ComEd Total			23,960.3		22,961.4
DEOK	Annual	$130.00	2,430.3	$130.00	2,430.3
	Summer	$130.00	14.8	$130.00	1.1
	Winter	$130.00	0.0	$130.00	0.0
DEOK Total			2,430.3		2,430.3

Table 29 Impact of Proposed CETL Values: 2020/2021 RPM Base Residual Auction Scenario 2

		Actual Auction Results		CETL Values Updated to Reflect Transmission Planning Process Changes	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$76.53	164,711.3	$74.50	164,741.7
	Summer	$76.53	397.9	$74.50	388.6
	Winter	$76.53	397.9	$74.50	388.6
RTO Total			165,109.2		165,130.3
MAAC	Annual	$86.04	65,727.3	$90.56	66,699.4
	Summer	$86.04	223.2	$90.56	181.5
	Winter	$86.04	90.6	$90.56	90.6
MAAC Total			65,817.9		66,790.0
EMAAC	Annual	$187.87	29,608.2	$182.29	30,144.7
	Summer	$187.87	67.6	$182.29	90.9
	Winter	$187.87	0.0	$182.29	0.0
EMAAC Total			29,608.2		30,144.7
PSEG	Annual	$187.87	5,097.2	$302.93	5,645.1
	Summer	$187.87	4.7	$302.93	0.0
	Winter	$187.87	0.0	$302.93	0.0
PSEG Total			5,097.2		5,645.1
ComEd	Annual	$188.12	23,811.4	$188.12	23,811.4
	Summer	$188.12	148.9	$188.12	148.9
	Winter	$188.12	148.9	$188.12	148.9
ComEd Total			23,960.3		23,960.3
DEOK	Annual	$130.00	2,430.3	$130.00	2,430.3
	Summer	$130.00	14.8	$130.00	46.5
	Winter	$130.00	0.0	$130.00	0.0
DEOK Total			2,430.3		2,430.3

Table 30 Impact of Load Forecast Reduction: 2020/2021 RPM Base Residual Auction Scenario 3

		Actual Auction Results		Reduce Load Forecast by 6.2 Percent	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$76.53	164,711.3	$58.28	154,182.5
	Summer	$76.53	397.9	$58.28	388.6
	Winter	$76.53	397.9	$58.28	388.6
RTO Total			165,109.2		154,571.1
MAAC	Annual	$86.04	65,727.3	$80.00	61,437.9
	Summer	$86.04	223.2	$80.00	236.3
	Winter	$86.04	90.6	$80.00	90.6
MAAC Total			65,817.9		61,528.5
EMAAC	Annual	$187.87	29,608.2	$134.29	27,669.3
	Summer	$187.87	67.6	$134.29	98.9
	Winter	$187.87	0.0	$134.29	0.0
EMAAC Total			29,608.2		27,669.3
ComEd	Annual	$188.12	23,811.4	$193.96	22,096.0
	Summer	$188.12	148.9	$193.96	148.9
	Winter	$188.12	148.9	$193.96	148.9
ComEd Total			23,960.3		22,244.9
DEOK	Annual	$130.00	2,430.3	$130.00	2,430.3
	Summer	$130.00	14.8	$130.00	0.6
	Winter	$130.00	0.0	$130.00	0.0
DEOK Total			2,430.3		2,430.3

Table 31 Offers greater than $35.00 per MW-day in total RTO supply curve: 2020/2021 RPM Base Residual Auction[127] [128]

Technology/Resource Type	Offered UCAP (MW)	Percent of Offers
Coal fired	26,977.9	35.0%
Combined cycle	18,917.1	24.6%
Combustion turbine	10,587.5	13.7%
Nuclear	7,815.8	10.1%
Oil or gas steam	5,197.3	6.7%
Demand Resource	4,142.4	5.4%
Hydro	1,933.5	2.5%
Energy Efficiency Resource	629.3	0.8%
Wind	420.8	0.5%
Other generation	213.6	0.3%
Solar	171.2	0.2%
Total	77,006.3	100.0%

127 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 2020/2021 BRA, waste coal resources are included in the coal fired category.

128 Data aggregated based on PJM confidentiality rules.

Table 32 DR and EE statistics by LDA: 2019/2020 and 2020/2021 RPM Base Residual Auctions

		2019/2020 BRA			2020/2021 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	10,859.2	11,818.0	10,348.0	8,373.2	9,113.0	7,677.1	(2,486.0)	(22.9%)	(2,705.0)	(22.9%)	(2,670.9)	(25.8%)
RTO	EE	1,517.4	1,650.3	1,515.1	1,877.7	2,042.4	1,659.2	360.3	23.7%	392.1	23.8%	144.1	9.5%
MAAC	DR	4,293.6	4,673.2	3,777.1	2,807.8	3,054.4	2,606.4	(1,485.8)	(34.6%)	(1,618.8)	(34.6%)	(1,170.7)	(31.0%)
MAAC	EE	455.4	495.0	426.9	590.0	641.0	526.9	134.6	29.6%	146.0	29.5%	100.0	23.4%
EMAAC	DR	1,640.9	1,786.1	1,636.5	1,097.5	1,193.3	1,085.7	(543.4)	(33.1%)	(592.8)	(33.2%)	(550.8)	(33.7%)
EMAAC	EE	189.3	205.5	160.8	289.5	314.0	288.7	100.2	52.9%	108.5	52.8%	127.9	79.5%
SWMAAC	DR	1,194.1	1,299.7	739.7	520.4	566.2	395.0	(673.7)	(56.4%)	(733.5)	(56.4%)	(344.7)	(46.6%)
SWMAAC	EE	171.0	185.9	179.7	199.1	216.8	179.8	28.1	16.4%	30.9	16.6%	0.1	0.1%
DPL South	DR	94.2	102.5	91.3	71.1	77.2	72.6	(23.1)	(24.5%)	(25.3)	(24.7%)	(18.7)	(20.5%)
DPL South	EE	0.9	1.0	1.0	7.9	8.6	8.6	7.0	777.8%	7.6	760.0%	7.6	760.0%
PSEG	DR	392.8	427.8	380.7	311.6	338.9	325.9	(81.2)	(20.7%)	(88.9)	(20.8%)	(54.8)	(14.4%)
PSEG	EE	54.7	59.6	49.3	94.5	102.5	92.8	39.8	72.7%	42.9	72.0%	43.5	88.2%
PSEG North	DR	171.6	187.2	176.5	132.9	144.3	141.4	(38.7)	(22.6%)	(42.9)	(22.9%)	(35.1)	(19.9%)
PSEG North	EE	7.8	8.4	8.4	18.9	20.4	17.9	11.1	141.9%	12.0	142.5%	9.5	113.1%
Pepco	DR	524.2	570.4	483.3	235.0	255.7	183.9	(289.2)	(55.2%)	(314.7)	(55.2%)	(299.4)	(61.9%)
Pepco	EE	78.2	85.2	79.0	73.3	79.7	60.8	(4.9)	(6.3%)	(5.5)	(6.5%)	(18.2)	(23.0%)
ATSI	DR	898.7	978.0	897.6	735.8	800.6	688.6	(162.9)	(18.1%)	(177.4)	(18.1%)	(209.0)	(23.3%)
ATSI	EE	48.5	52.8	41.0	45.9	49.8	32.5	(2.6)	(5.3%)	(3.0)	(5.7%)	(8.5)	(20.7%)
ATSI Cleveland	DR	281.1	305.9	289.9	184.6	200.9	168.9	(96.5)	(34.3%)	(105.0)	(34.3%)	(121.0)	(41.7%)
ATSI Cleveland	EE	0.2	0.2	0.2	0.4	0.4	0.4	0.2	100.0%	0.2	100.0%	0.2	100.0%
ComEd	DR	1,646.7	1,792.0	1,757.4	1,485.2	1,617.4	1,469.8	(161.5)	(9.8%)	(174.6)	(9.7%)	(287.6)	(16.4%)
ComEd	EE	666.2	725.1	724.8	665.6	724.7	671.2	(0.6)	(0.1%)	(0.4)	(0.0%)	(53.6)	(7.4%)
BGE	DR	669.9	729.3	256.4	285.4	310.5	211.0	(384.5)	(57.4%)	(418.8)	(57.4%)	(45.4)	(17.7%)
BGE	EE	92.8	100.7	100.7	125.8	137.1	119.1	33.0	35.6%	36.4	36.2%	18.4	18.2%
PPL	DR	749.3	815.6	739.8	604.6	658.4	579.9	(144.7)	(19.3%)	(157.2)	(19.3%)	(159.9)	(21.6%)
PPL	EE	52.2	56.8	50.9	49.8	54.2	34.0	(2.4)	(4.6%)	(2.6)	(4.6%)	(16.9)	(33.3%)
DAY	DR	218.4	237.6	219.8	189.2	205.8	164.5	(29.2)	(13.4%)	(31.8)	(13.4%)	(55.3)	(25.2%)
DAY	EE	23.9	25.9	24.5	43.7	47.4	32.9	19.8	82.7%	21.5	82.8%	8.4	34.1%
DEOK	DR	228.5	248.8	236.7	157.0	170.3	145.7	(71.5)	(31.3%)	(78.5)	(31.6%)	(91.0)	(38.4%)
DEOK	EE	28.7	31.2	24.4	61.1	66.4	65.6	32.4	112.7%	35.2	112.7%	41.2	168.7%

Table 33 Impact of demand side products: 2020/2021 RPM Base Residual Auction Scenario 4

		Actual Auction Results		No Offers for DR or EE	
LDA	Season	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$76.53	164,711.3	$102.04	161,552.9
	Summer	$76.53	397.9	$102.04	184.2
	Winter	$76.53	397.9	$102.04	184.2
RTO Total			165,109.2		161,737.1
MAAC	Annual	$86.04	65,727.3	$102.04	65,090.9
	Summer	$86.04	223.2	$102.04	92.7
	Winter	$86.04	90.6	$102.04	22.0
MAAC Total			65,817.9		65,112.9
EMAAC	Annual	$187.87	29,608.2	$192.11	29,154.0
	Summer	$187.87	67.6	$192.11	56.2
	Winter	$187.87	0.0	$192.11	0.0
EMAAC Total			29,608.2		29,154.0
ComEd	Annual	$188.12	23,811.4	$226.59	22,923.6
	Summer	$188.12	148.9	$226.59	0.0
	Winter	$188.12	148.9	$226.59	88.4
ComEd Total			23,960.3		22,923.6
DEOK	Annual	$130.00	2,430.3	$130.00	2,338.7
	Summer	$130.00	14.8	$130.00	0.0
	Winter	$130.00	0.0	$130.00	0.0
DEOK Total			2,430.3		2,338.7

Table 34 Impact of EE Resources: 2020/2021 RPM Base Residual Auction

Scenario 5

		Actual Auction Results		No Offers for EE and EE Add Back Removed	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$76.53	164,711.3	$74.50	162,359.9
	Summer	$76.53	397.9	$74.50	388.6
	Winter	$76.53	397.9	$74.50	388.6
RTO Total			165,109.2		162,748.5
MAAC	Annual	$86.04	65,727.3	$85.00	64,970.5
	Summer	$86.04	223.2	$85.00	168.9
	Winter	$86.04	90.6	$85.00	90.6
MAAC Total			65,817.9		65,061.1
EMAAC	Annual	$187.87	29,608.2	$179.20	29,267.6
	Summer	$187.87	67.6	$179.20	78.3
	Winter	$187.87	0.0	$179.20	0.0
EMAAC Total			29,608.2		29,267.6
ComEd	Annual	$188.12	23,811.4	$185.03	22,997.7
	Summer	$188.12	148.9	$185.03	172.0
	Winter	$188.12	148.9	$185.03	148.9
ComEd Total			23,960.3		23,146.6
DEOK	Annual	$130.00	2,430.3	$130.00	2,345.9
	Summer	$130.00	14.8	$130.00	45.7
	Winter	$130.00	0.0	$130.00	0.0
DEOK Total			2,430.3		2,345.9

Table 35 Impact of Annual demand side products: 2020/2021 RPM Base Residual Auction

Scenario 6

		Actual Auction Results		No Offers for Annual DR or EE	
LDA	Season	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$76.53	164,711.3	$100.00	161,511.6
	Summer	$76.53	397.9	$100.00	485.9
	Winter	$76.53	397.9	$100.00	485.9
RTO Total			165,109.2		161,997.5
MAAC	Annual	$86.04	65,727.3	$100.00	65,135.1
	Summer	$86.04	223.2	$100.00	323.4
	Winter	$86.04	90.6	$100.00	111.6
MAAC Total			65,817.9		65,246.7
EMAAC	Annual	$187.87	29,608.2	$195.04	29,233.5
	Summer	$187.87	67.6	$195.04	15.6
	Winter	$187.87	0.0	$195.04	0.0
EMAAC Total			29,608.2		29,233.5
ComEd	Annual	$188.12	23,811.4	$216.80	22,914.0
	Summer	$188.12	148.9	$216.80	155.7
	Winter	$188.12	148.9	$216.80	148.9
ComEd Total			23,960.3		23,062.9
DEOK	Annual	$130.00	2,430.3	$130.00	2,338.7
	Summer	$130.00	14.8	$130.00	1.6
	Winter	$130.00	0.0	$130.00	0.0
DEOK Total			2,430.3		2,338.7

Table 36 Impact of Seasonal demand side products: 2020/2021 RPM Base Residual Auction

Scenario 7

		Actual Auction Results		No Seasonal Offers for DR or EE	
LDA	Season	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$76.53	164,711.3	$77.50	164,745.6
	Summer	$76.53	397.9	$77.50	182.9
	Winter	$76.53	397.9	$77.50	182.9
RTO Total			165,109.2		164,928.5
MAAC	Annual	$86.04	65,727.3	$86.03	65,714.7
	Summer	$86.04	223.2	$86.03	91.4
	Winter	$86.04	90.6	$86.03	50.9
MAAC Total			65,817.9		65,765.6
EMAAC	Annual	$187.87	29,608.2	$187.87	29,595.6
	Summer	$187.87	67.6	$187.87	54.9
	Winter	$187.87	0.0	$187.87	0.0
EMAAC Total			29,608.2		29,595.6
ComEd	Annual	$188.12	23,811.4	$185.04	23,803.9
	Summer	$188.12	148.9	$185.04	0.0
	Winter	$188.12	148.9	$185.04	76.7
ComEd Total			23,960.3		23,803.9
DEOK	Annual	$130.00	2,430.3	$130.00	2,427.4
	Summer	$130.00	14.8	$130.00	0.0
	Winter	$130.00	0.0	$130.00	0.0
DEOK Total			2,430.3		2,427.4

Table 37 Impact of Seasonal products: 2020/2021 RPM Base Residual Auction Scenario 8

		Actual Auction Results		Annual Only	
LDA	Season	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$76.53	164,711.3	$79.00	164,875.4
	Summer	$76.53	397.9	$79.00	0.0
	Winter	$76.53	397.9	$79.00	0.0
RTO Total			165,109.2		164,875.4
MAAC	Annual	$86.04	65,727.3	$86.30	65,761.4
	Summer	$86.04	223.2	$86.30	0.0
	Winter	$86.04	90.6	$86.30	0.0
MAAC Total			65,817.9		65,761.4
EMAAC	Annual	$187.87	29,608.2	$187.87	29,595.6
	Summer	$187.87	67.6	$187.87	0.0
	Winter	$187.87	0.0	$187.87	0.0
EMAAC Total			29,608.2		29,595.6
ComEd	Annual	$188.12	23,811.4	$185.04	23,803.9
	Summer	$188.12	148.9	$185.04	0.0
	Winter	$188.12	148.9	$185.04	0.0
ComEd Total			23,960.3		23,803.9
DEOK	Annual	$130.00	2,430.3	$130.00	2,427.4
	Summer	$130.00	14.8	$130.00	0.0
	Winter	$130.00	0.0	$130.00	0.0
DEOK Total			2,430.3		2,427.4

Table 38 Impact of demand side and Seasonal products: 2020/2021 RPM Base Residual Auction

Scenario 9

		Actual Auction Results		Annual Generation Offers Only	
LDA	Season	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$76.53	164,711.3	$104.30	161,689.2
	Summer	$76.53	397.9	$104.30	0.0
	Winter	$76.53	397.9	$104.30	0.0
RTO Total			165,109.2		161,689.2
MAAC	Annual	$86.04	65,727.3	$104.30	65,613.1
	Summer	$86.04	223.2	$104.30	0.0
	Winter	$86.04	90.6	$104.30	0.0
MAAC Total			65,817.9		65,613.1
EMAAC	Annual	$187.87	29,608.2	$192.11	29,154.0
	Summer	$187.87	67.6	$192.11	0.0
	Winter	$187.87	0.0	$192.11	0.0
EMAAC Total			29,608.2		29,154.0
ComEd	Annual	$188.12	23,811.4	$226.59	22,923.6
	Summer	$188.12	148.9	$226.59	0.0
	Winter	$188.12	148.9	$226.59	0.0
ComEd Total			23,960.3		22,923.6
DEOK	Annual	$130.00	2,430.3	$130.00	2,338.7
	Summer	$130.00	14.8	$130.00	0.0
	Winter	$130.00	0.0	$130.00	0.0
DEOK Total			2,430.3		2,338.7

Table 39 Impact of Winter Resources: 2020/2021 RPM Base Residual Auction Scenario 10

		Actual Auction Results		Reduce Winter Offers by 50 Percent	
LDA	Season	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$76.53	164,711.3	$84.00	164,563.3
	Summer	$76.53	397.9	$84.00	200.0
	Winter	$76.53	397.9	$84.00	200.0
RTO Total			165,109.2		164,763.3
MAAC	Annual	$86.04	65,727.3	$86.30	65,716.7
	Summer	$86.04	223.2	$86.30	123.4
	Winter	$86.04	90.6	$86.30	45.7
MAAC Total			65,817.9		65,762.4
EMAAC	Annual	$187.87	29,608.2	$187.87	29,595.6
	Summer	$187.87	67.6	$187.87	77.7
	Winter	$187.87	0.0	$187.87	0.0
EMAAC Total			29,608.2		29,595.6
ComEd	Annual	$188.12	23,811.4	$170.02	22,886.8
	Summer	$188.12	148.9	$170.02	74.6
	Winter	$188.12	148.9	$170.02	74.6
ComEd Total			23,960.3		22,961.4
DEOK	Annual	$130.00	2,430.3	$130.00	2,430.3
	Summer	$130.00	14.8	$130.00	0.8
	Winter	$130.00	0.0	$130.00	0.0
DEOK Total			2,430.3		2,430.3

Table 40 Impact of Seasonal Matching Across LDAs: 2020/2021 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	$76.53	164,711.3	$77.50	164,759.5
	Summer	$76.53	397.9	$77.50	363.4
	Winter	$76.53	397.9	$77.50	363.4
RTO Total			165,109.2		165,122.9
MAAC	Annual	$86.04	65,727.3	$86.30	65,730.2
	Summer	$86.04	223.2	$86.30	65.4
	Winter	$86.04	90.6	$86.30	65.4
MAAC Total			65,817.9		65,795.6
EMAAC	Annual	$187.87	29,608.2	$187.87	29,595.6
	Summer	$187.87	67.6	$187.87	0.0
	Winter	$187.87	0.0	$187.87	0.0
EMAAC Total			29,608.2		29,595.6
ComEd	Annual	$188.12	23,811.4	$188.12	23,811.4
	Summer	$188.12	148.9	$188.12	148.9
	Winter	$188.12	148.9	$188.12	148.9
ComEd Total			23,960.3		23,960.3
DEOK	Annual	$130.00	2,430.3	$130.00	2,430.3
	Summer	$130.00	14.8	$130.00	0.0
	Winter	$130.00	0.0	$130.00	0.0
DEOK Total			2,430.3		2,430.3

Table 41 Impact of capacity imports: 2020/2021 RPM Base Residual Auction: 2020/2021 RPM Base Residual Auction

Scenario 12, Scenario 13, Scenario 14

		Actual Auction Results		Reduce Imports 25 percent		Reduce Imports 50 percent		Reduce Imports 75 percent	
LDA	Season	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$76.53	164,711.3	$85.44	164,527.3	$90.00	164,326.5	$95.56	164,087.7
	Summer	$76.53	397.9	$85.44	397.9	$90.00	397.9	$95.56	464.9
	Winter	$76.53	397.9	$85.44	397.9	$90.00	397.9	$95.56	464.9
RTO Total			165,109.2		164,925.2		164,724.4		164,552.6
MAAC	Annual	$86.04	65,727.3	$85.73	65,714.6	$90.00	66,116.1	$95.56	66,568.3
	Summer	$86.04	223.2	$85.73	188.0	$90.00	194.8	$95.56	307.4
	Winter	$86.04	90.6	$85.73	90.6	$90.00	90.6	$95.56	90.6
MAAC Total			65,817.9		65,805.2		66,206.7		66,658.9
EMAAC	Annual	$187.87	29,608.2	$187.87	29,595.6	$187.87	29,595.6	$187.87	29,595.6
	Summer	$187.87	67.6	$187.87	97.4	$187.87	130.9	$187.87	194.8
	Winter	$187.87	0.0	$187.87	0.0	$187.87	0.0	$187.87	0.0
EMAAC Total			29,608.2		29,595.6		29,595.6		29,595.6
ComEd	Annual	$188.12	23,811.4	$170.02	22,812.5	$170.02	22,812.5	$170.02	22,812.5
	Summer	$188.12	148.9	$170.02	148.9	$170.02	148.9	$170.02	148.9
	Winter	$188.12	148.9	$170.02	148.9	$170.02	148.9	$170.02	148.9
ComEd Total			23,960.3		22,961.4		22,961.4		22,961.4
DEOK	Annual	$130.00	2,430.3	$130.00	2,430.3	$130.00	2,430.3	$130.00	2,430.3
	Summer	$130.00	14.8	$130.00	47.3	$130.00	47.1	$130.00	0.8
	Winter	$130.00	0.0	$130.00	0.0	$130.00	0.0	$130.00	0.0
DEOK Total			2,430.3		2,430.3		2,430.3		2,430.3

Table 42 Impact of demand side and Seasonal products, and capacity imports: 2020/2021 RPM Base Residual Auction

Scenario 15

		Actual Auction Results		No DR, Reduce Imports 75 pct	
LDA	Season	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$76.53	164,711.3	$130.77	160,748.5
	Summer	$76.53	397.9	$130.77	0.0
	Winter	$76.53	397.9	$130.77	0.0
RTO Total			165,109.2		160,748.5
MAAC	Annual	$86.04	65,727.3	$130.77	66,853.5
	Summer	$86.04	223.2	$130.77	0.0
	Winter	$86.04	90.6	$130.77	0.0
MAAC Total			65,817.9		66,853.5
EMAAC	Annual	$187.87	29,608.2	$192.11	29,154.0
	Summer	$187.87	67.6	$192.11	0.0
	Winter	$187.87	0.0	$192.11	0.0
EMAAC Total			29,608.2		29,154.0
ComEd	Annual	$188.12	23,811.4	$226.59	22,923.6
	Summer	$188.12	148.9	$226.59	0.0
	Winter	$188.12	148.9	$226.59	0.0
ComEd Total			23,960.3		22,923.6
DEOK	Annual	$130.00	2,430.3	$130.77	2,338.7
	Summer	$130.00	14.8	$130.77	0.0
	Winter	$130.00	0.0	$130.77	0.0
DEOK Total			2,430.3		2,338.7

Table 43 Impact of inconsistency between EE cleared MW and EE Add back MW: 2020/2021 RPM Base Residual Auction

Scenario 16

		Actual Auction Results		EE Add Back Equal to Cleared EE	
LDA	Season	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$76.53	164,711.3	$74.75	164,040.4
	Summer	$76.53	397.9	$74.75	388.6
	Winter	$76.53	397.9	$74.75	388.6
RTO Total			165,109.2		164,429.0
MAAC	Annual	$86.04	65,727.3	$85.00	65,483.5
	Summer	$86.04	223.2	$85.00	236.5
	Winter	$86.04	90.6	$85.00	90.6
MAAC Total			65,817.9		65,574.1
EMAAC	Annual	$187.87	29,608.2	$179.20	29,551.8
	Summer	$187.87	67.6	$179.20	98.8
	Winter	$187.87	0.0	$179.20	0.0
EMAAC Total			29,608.2		29,551.8
ComEd	Annual	$188.12	23,811.4	$190.30	23,699.1
	Summer	$188.12	148.9	$190.30	148.9
	Winter	$188.12	148.9	$190.30	148.9
ComEd Total			23,960.3		23,848.0
DEOK	Annual	$130.00	2,430.3	$130.00	2,411.2
	Summer	$130.00	14.8	$130.00	0.9
	Winter	$130.00	0.0	$130.00	0.0
DEOK Total			2,430.3		2,411.2

Table 44 Impact of Price Responsive Demand: 2020/2021 RPM Base Residual Auction Scenario 17

		Actual Auction Results		No PRD Offers	
LDA	Season	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$76.53	164,711.3	$77.58	165,303.7
	Summer	$76.53	397.9	$77.58	397.9
	Winter	$76.53	397.9	$77.58	397.9
RTO Total			165,109.2		165,701.6
MAAC	Annual	$86.04	65,727.3	$91.29	66,251.6
	Summer	$86.04	223.2	$91.29	235.0
	Winter	$86.04	90.6	$91.29	90.6
MAAC Total			65,817.9		66,342.2
EMAAC	Annual	$187.87	29,608.2	$187.87	29,658.8
	Summer	$187.87	67.6	$187.87	157.3
	Winter	$187.87	0.0	$187.87	0.0
EMAAC Total			29,608.2		29,658.8
BGE	Annual	$86.04	2,296.9	$114.99	2,314.9
	Summer	$86.04	83.7	$114.99	33.5
	Winter	$86.04	0.0	$114.99	0.0
BGE Total			2,296.9		2,314.9
ComEd	Annual	$188.12	23,811.4	$188.12	23,811.4
	Summer	$188.12	148.9	$188.12	148.9
	Winter	$188.12	148.9	$188.12	148.9
ComEd Total			23,960.3		23,960.3
DEOK	Annual	$130.00	2,430.3	$130.00	2,430.3
	Summer	$130.00	14.8	$130.00	1.9
	Winter	$130.00	0.0	$130.00	0.0
DEOK Total			2,430.3		2,430.3

Table 45 Peak Load Forecast History[129] [130][131]

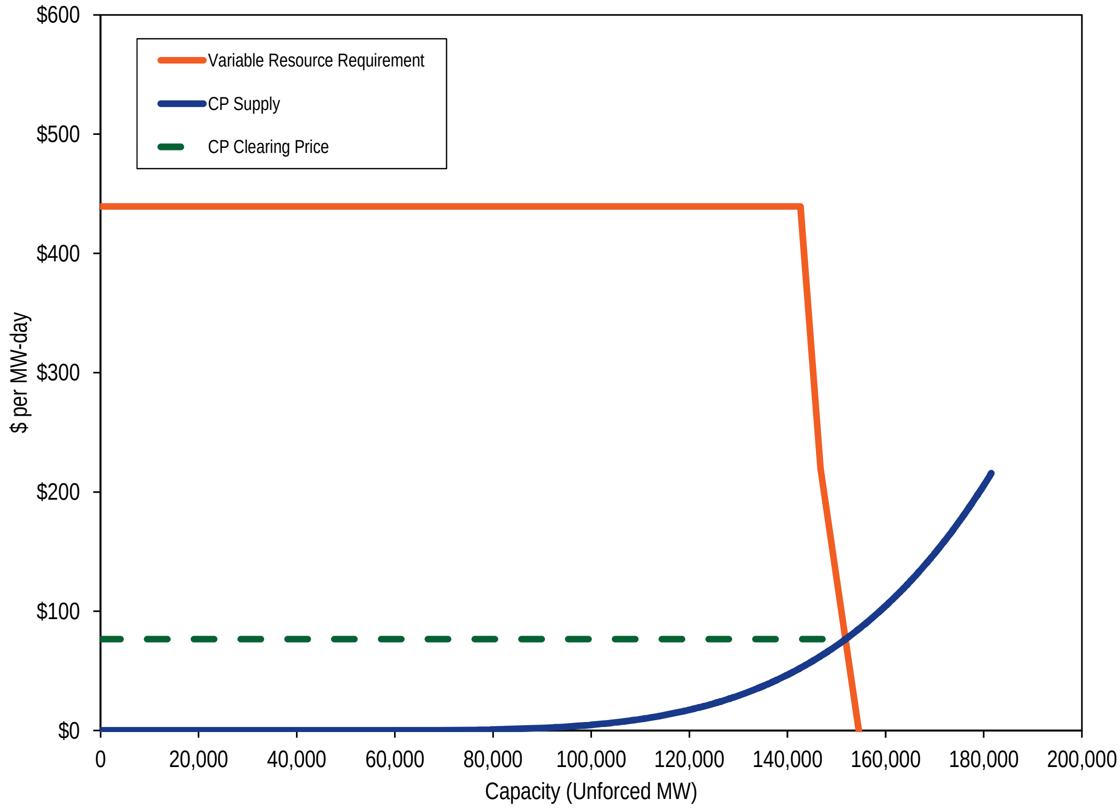
	DY	BRA	First IA	Second IA	Third IA	Actual DY Peak Load	Percent Change BRA to 1st	Percent Change BRA to 2nd	Percent Change BRA to 3rd	Percent Change BRA to Actual
Forecast Peak Load	2019/2020	157,188.5	154,510.0				(1.7%)			
Installed Reverve Margin		16.50%	16.60%				0.6%			
Pool Wide EFORd		6.60%	6.59%				(0.2%)			
Forecast Pool Requirement		1.0881	1.0892				0.1%			
Reliability Requirement		171,036.8	168,292.3				(1.6%)			
Forecast Peak Load	2018/2019	161,418.4	156,141.1	154,179.9			(3.3%)	(4.5%)		
Installed Reverve Margin		15.70%	16.50%	16.70%			5.1%	6.4%		
Pool Wide EFORd		6.35%	6.58%	6.59%			3.6%	3.8%		
Forecast Pool Requirement		1.0835	1.0883	1.0901			0.4%	0.6%		
Reliability Requirement		174,896.8	169,928.4	168,071.5			(2.8%)	(3.9%)		
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		15.70%	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		15.60%	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%)	
Forecast Peak Load	2015/2016	163,168.0	160,325.0	160,538.2	155,823.3	143,696.7	(1.7%)	(1.6%)	(4.5%)	(11.9%)
Installed Reverve Margin		15.40%	15.30%	15.70%	15.60%		(0.6%)	1.9%	1.3%	
Pool Wide EFORd		5.90%	5.91%	5.62%	5.60%		0.2%	(4.7%)	(5.1%)	
Forecast Pool Requirement		1.0859	1.0849	1.092	1.0913		(0.1%)	0.6%	0.5%	
Reliability Requirement		177,184.1	173,936.6	175,307.7	170,050.0		(1.8%)	(1.1%)	(4.0%)	
Forecast Peak Load	2014/2015	164,757.6	159,845.0	156,863.0	157,562.8	143,114.9	(3.0%)	(4.8%)	(4.4%)	(13.1%)
Installed Reverve Margin		15.30%	15.40%	15.90%	16.20%		0.7%	3.9%	5.9%	
Pool Wide EFORd		6.25%	5.89%	6.05%	5.97%		(5.8%)	(3.2%)	(4.5%)	
Forecast Pool Requirement		1.0809	1.086	1.0889	1.0926		0.5%	0.7%	1.1%	
Reliability Requirement		178,086.5	173,591.7	170,808.1	172,153.1		(2.5%)	(4.1%)	(3.3%)	
Forecast Peak Load	2013/2014	160,634.0	156,749.0	150,828.0	148,451.0	157,508.5	(2.4%)	(6.1%)	(7.6%)	(1.9%)
Installed Reverve Margin		15.30%	15.30%	15.40%	15.90%		0.0%	0.7%	3.9%	
Pool Wide EFORd		6.30%	6.25%	5.90%	6.05%		(0.8%)	(6.3%)	(4.0%)	
Forecast Pool Requirement		1.0804	1.0809	1.0859	1.0889		0.0%	0.5%	0.8%	
Reliability Requirement		173,549.0	169,430.0	163,784.1	161,648.3		(2.4%)	(5.6%)	(6.9%)	

129 PJM made changes to the load forecast model in December 2015. See Revision 29 in PJM Manual 19 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, 2017/2018 Third IA, 2018/2019 First IA, 2018/2019 Second IA, 2019/2020 BRA, 2019/2020 First IA.

130 Actual peak load is the largest hourly load for a given delivery year. Actual peak load for 2017/2018 is the largest hourly load for the partial delivery year beginning June 1, 2017.

131 The data has not been adjusted to reflect the integration of the DEOK Control Zone (January 1, 2012) and the EKPC Control Zone (June 1, 2013). Forecasts and actual peak load for Delivery Years 2013/2014, 2014/2015, and 2015/2016 are affected.

Figure 1 RTO market supply/demand curves: 2020/2021 RPM Base Residual Auction[132] [133]



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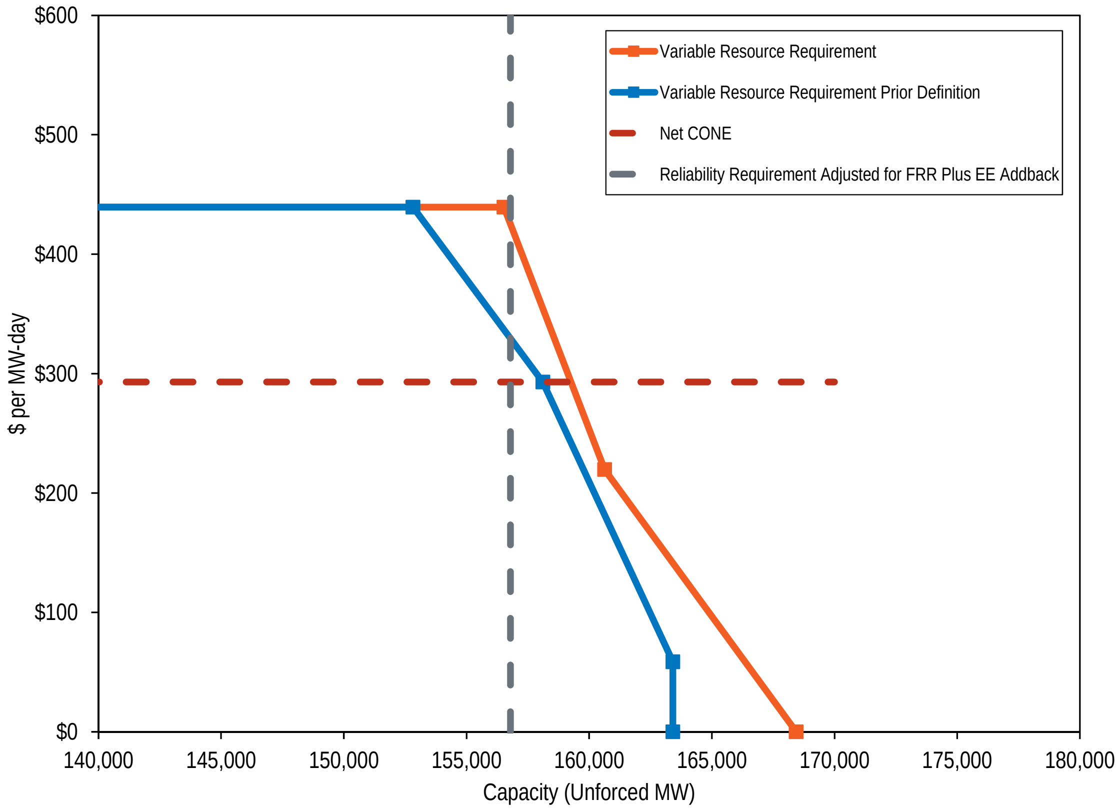
132 The supply curves presented in this report have all been smoothed using a statistical technique that fits a smooth curve to the underlying supply curve data while ensuring that the point of intersection between supply and demand curves is at the market clearing price. The supply curve includes all 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.

133 The VRR curve excludes incremental demand which cleared in MAAC, EMAAC, ComEd, and DEOK.

Figure 2 RTO VRR curve shape comparison



MAAC LDA Market Results

Table 47 shows total MAAC LDA offer data for the 2020/2021 RPM Base Residual Auction. Total internal MAAC LDA unforced capacity, excluding generation winter capacity, of 75,939.0 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 17, MAAC LDA unforced internal capacity decreased 1,339.5 MW from 77,278.5 MW in the 2019/2020 BRA as a result of net generation capacity modifications (-970.3 MW), net DR modifications (-1,207.9 MW), and net EE modifications (236.1 MW), the EFORd effect due to lower sell offer EFORds (599.1 MW), and the DR and EE effect due to a higher Load Management UCAP conversion factor (3.5 MW). As shown in Table 19, total internal MAAC unforced winter capacity increased by 109.2 MW for November through April of the 2020/2021 Delivery Year as a result of net generation winter capacity modifications (109.2 MW).

All imports offered in the auction from areas external to PJM are modeled as supply in the rest of RTO.[134] Total internal MAAC capacity was reduced by FRR commitments of 0.0 MW, resulting in MAAC LDA RPM capacity of 75,993.2 MW. RPM capacity was reduced by 669.8 MW of exports, 0.0 MW of FRR optional volumes not offered, 483.6 MW excused from the RPM must offer requirement, 68.8 MW of Planned Generation Capacity Resources which were not subject to the RPM must offer requirement, and 952.7 MW of intermittent resources and 426.6 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 (270.4 MW), and the resources being reasonably expected to be physically incapable of satisfying the requirements of a Capacity Performance Resource (213.2 MW). Subtracting 991.7 MW of DR and EE not offered and 5.3 MW of unoffered generation winter capacity resulted in available unforced capacity in MAAC LDA of 72,394.7 MW.[135] 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 2020/2021 BRA. Of the 65,817.9 MW cleared in MAAC LDA, 56,736.1 MW were cleared in the RTO before MAAC LDA became constrained. Once the constraint was binding, based on the 4,218.0 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, 9,081.8 MW cleared, which resulted in a clearing price for Capacity Performance Resources of $86.04 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 14, the 65,272.9 MW of cleared and make whole and generation and DR for MAAC LDA and 4,218.0 MW CETL resulted in a net excess of 3,105.9 MW.

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[134] "PJM Manual 18: PJM Capacity Market," Rev. 37 (April 27, 2017) at 17.

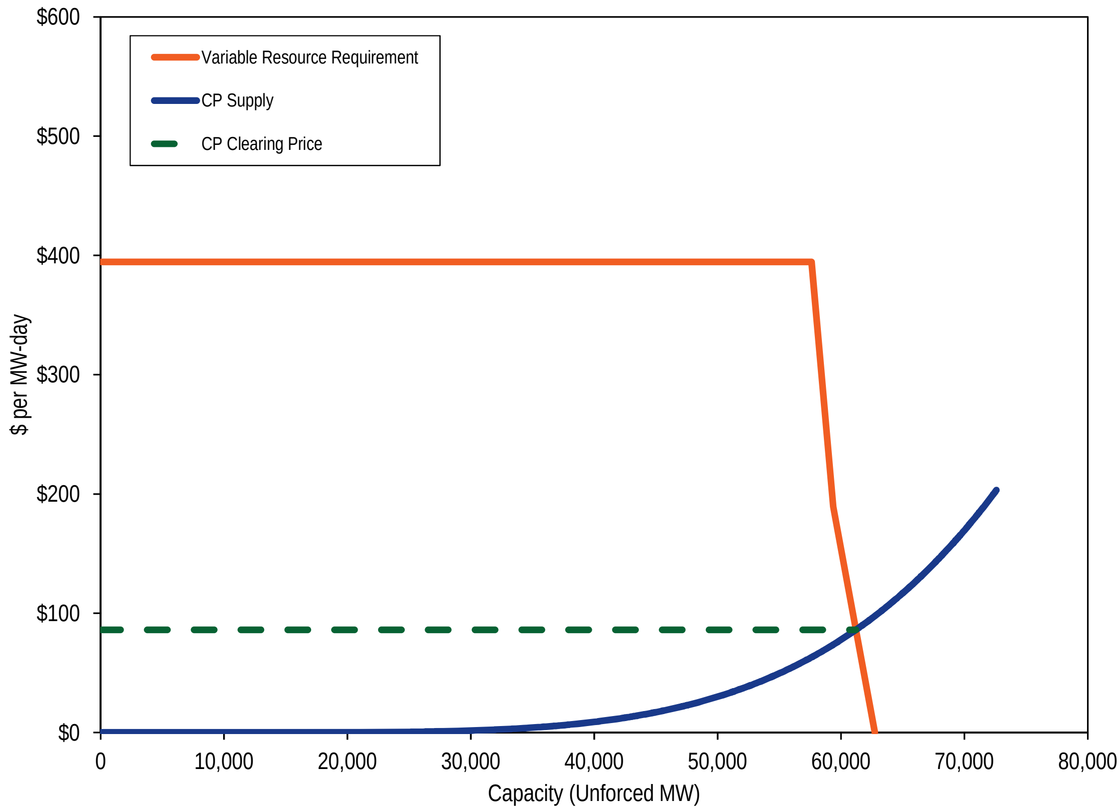
[135] Unoffered DR and EE MW include PJM approved DR and EE plans that were not offered in the auction.

Table and Figures for MAAC LDA

Table 46 MAAC LDA offer statistics: 2020/2021 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	73,941.8	71,252.1		
DR capacity	3,574.0	3,892.5		
EE capacity	730.7	794.4		
Generation winter capacity	54.2	54.2		
Total internal MAAC LDA capacity	78,300.7	75,993.2		
FRR	0.0	0.0		
Imports	0.0	0.0		
RPM capacity	78,300.7	75,993.2		
Exports	(674.0)	(669.8)		
FRR optional	0.0	0.0		
Excused Existing Generation Capacity Resources	(537.3)	(483.6)		
Unoffered Planned Generation Capacity Resources	(71.8)	(68.8)		
Unoffered Intermittent Resources	(966.0)	(952.7)		
Unoffered Capacity Storage Resources	(430.3)	(426.6)		
Unoffered generation winter capacity	(5.3)	(5.3)		
Unoffered DR and EE	(906.9)	(991.7)		
Available	74,709.1	72,394.7	100.0%	100.0%
Generation offered	71,311.3	68,699.3	95.5%	94.9%
DR offered	2,807.8	3,054.4	3.8%	4.2%
EE offered	590.0	641.0	0.8%	0.9%
Total offered	74,709.1	72,394.7	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%

Figure 3 MAAC LDA market supply/demand curves: 2020/2021 RPM Base Residual Auction[136]



EMAAC LDA Market Results

Table 47 shows total EMAAC LDA offer data for the 2020/2021 RPM Base Residual Auction. Total internal EMAAC LDA unforced capacity, excluding generation winter capacity, of 33,173.4 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 17, EMAAC LDA unforced internal capacity decreased 2,326.7 MW from 35,500.1 MW in the 2019/2020 BRA as a result of net generation capacity modifications (-1,972.3 MW), net DR modifications (-458.4 MW), and net EE modifications (148.7 MW), the EFORd effect due to higher sell offer EFORds (-46.1 MW), and the DR and EE effect due to a higher Load Management UCAP conversion factor (1.4 MW). As shown in

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

Table 19, total internal EMAAC unforced winter capacity increased by 0.0 MW for November through April of the 2020/2021 Delivery Year.

All imports offered in the auction from areas external to PJM are modeled as supply in the rest of RTO.[137] Total internal EMAAC LDA was reduced by FRR commitments of 0.0 MW, resulting in EMAAC LDA RPM capacity of 33,173.4 MW. RPM capacity was reduced by 669.8 MW of exports, 0.0 MW of FRR optional volumes not offered, 153.7 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 714.0 MW of intermittent resources and 426.6 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 (152.8 MW), and the resources being reasonably expected to be physically incapable of satisfying the requirements of a Capacity Performance Resource (0.9 MW). Subtracting 356.6 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 30,852.7 MW.[138] 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 2020/2021 BRA. Of the 29,608.2 MW cleared in EMAAC LDA, 23,160.9 MW were cleared in the RTO and an additional 1,235.0 MW were cleared in MAAC before EMAAC LDA became constrained. Once the constraint was binding, based on the 8,800.0 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, 5,212.3 MW cleared, which resulted in a clearing price for Capacity Performance Resources of $187.87 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 14, the 29,315.1 MW of cleared and make whole and generation and DR for EMAAC LDA and 8,800.0 MW CETL resulted in a net excess of 1,194.1 MW.

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137 "PJM Manual 18: PJM Capacity Market," Rev. 37 (April 27, 2017) at 17.

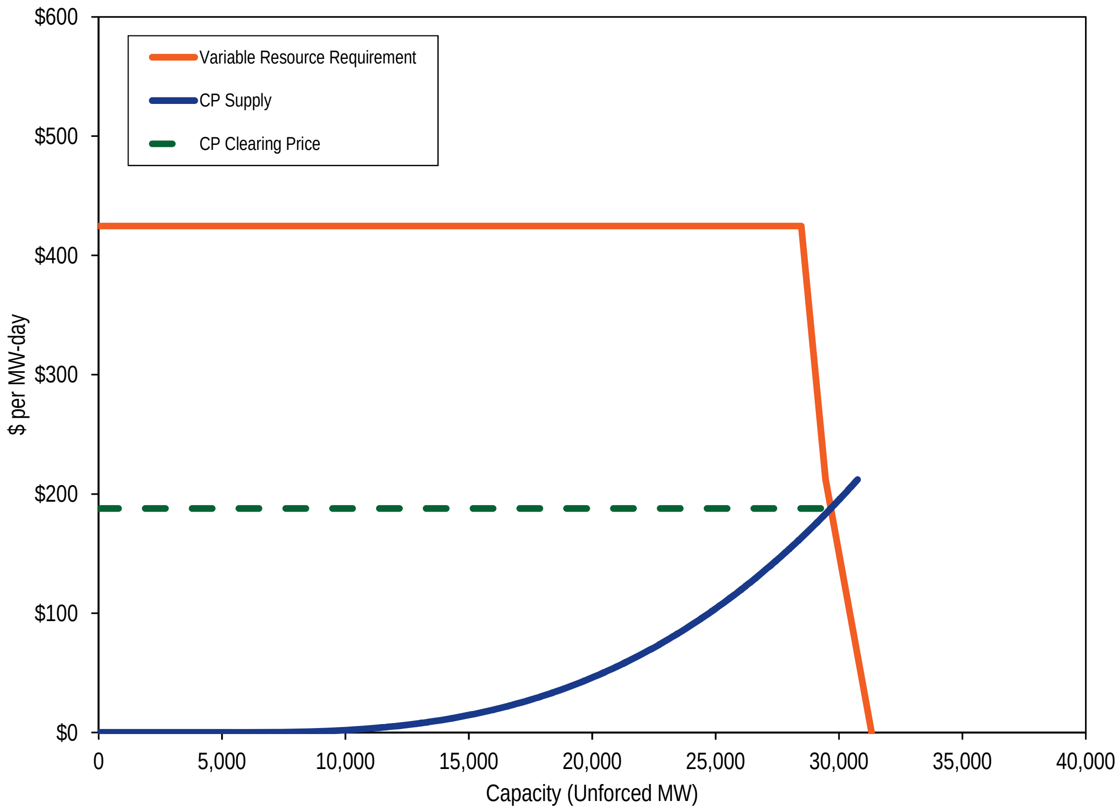
138 Unoffered DR and EE MW include PJM approved DR and EE plans that were not offered in the auction.

Table and Figures for EMAAC LDA

Table 47 EMAAC LDA offer statistics: 2020/2021 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	32,662.0	31,309.6		
DR capacity	1,371.6	1,493.8		
EE capacity	340.7	370.0		
Generation winter capacity	0.0	0.0		
Total internal EMAAC LDA capacity	34,374.3	33,173.4		
FRR	0.0	0.0		
Imports	0.0	0.0		
RPM capacity	34,374.3	33,173.4		
Exports	(674.0)	(669.8)		
FRR optional	0.0	0.0		
Excused Existing Generation Capacity Resources	(170.2)	(153.7)		
Unoffered Planned Generation Capacity Resources	0.0	0.0		
Unoffered Intermittent Resources	(715.7)	(714.0)		
Unoffered Capacity Storage Resources	(430.3)	(426.6)		
Unoffered generation winter capacity	0.0	0.0		
Unoffered DR and EE	(325.2)	(356.6)		
Available	32,058.8	30,852.7	100.0%	100.0%
Generation offered	30,671.8	29,345.4	95.7%	95.1%
DR offered	1,097.5	1,193.3	3.4%	3.9%
EE offered	289.5	314.0	0.9%	1.0%
Total offered	32,058.8	30,852.7	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%

Figure 4 EMAAC LDA market supply/demand curves: 2020/2021 RPM Base Residual Auction[139]



ComEd LDA Market Results

Table 48 shows total ComEd LDA offer data for the 2020/2021 RPM Base Residual Auction. Total internal ComEd LDA unforced capacity, excluding generation winter capacity, of 28,250.8 MW includes all Generation Capacity Resources, Demand Resources, and Energy Efficiency Resources that qualified as PJM Capacity Resources, excludes external units, and also includes owners' modifications to ICAP ratings. As shown in Table 17, ComEd LDA unforced internal capacity increased 439.7 MW from 27,811.1 MW in the 2019/2020 BRA as a result of net generation capacity modifications (-12.2 MW), net DR modifications (27.3 MW), and net EE modifications (92.0 MW), the EFORd effect due to lower sell offer EFORds (329.8 MW), and the DR and EE effect due to a higher Load Management UCAP conversion factor (2.8 MW). As shown in Table 19, total internal ComEd unforced winter capacity increased by 248.7 MW for November

139 The VRR curve is reduced by the CETL.

through April of the 2020/2021 Delivery Year as a result of net generation winter capacity modifications (248.7 MW).

All imports offered in the auction from areas external to PJM are modeled as supply in the rest of RTO.[140] Total internal ComEd LDA capacity was reduced by FRR commitments of 30.0 MW, resulting in ComEd LDA RPM capacity of 28,344.1 MW. RPM capacity was reduced by 537.9 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 225.6 MW of intermittent resources and 0.0 MW of capacity storage resources which were not subject to the CP must offer requirement. Subtracting 479.3 MW of DR and EE not offered and 0.0 MW of unoffered generation winter capacity resulted in available unforced capacity in ComEd LDA of 27,101.3 MW.[141] 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 2020/2021 BRA. Of the 23,960.3 MW cleared in ComEd LDA, 20,083.9 MW were cleared in the RTO before ComEd LDA became constrained. Once the constraint was binding, based on the 4,064.0 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, 3,876.4 MW cleared, which resulted in a clearing price for Capacity Performance Resources of $188.12 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 14, the 23,258.4 MW of cleared and make whole and generation and DR for ComEd LDA and 4,064.0 MW CETL resulted in a net excess of 1,098.4 MW.

140 "PJM Manual 18: PJM Capacity Market," Rev.37 (April 27, 2017) at 17.

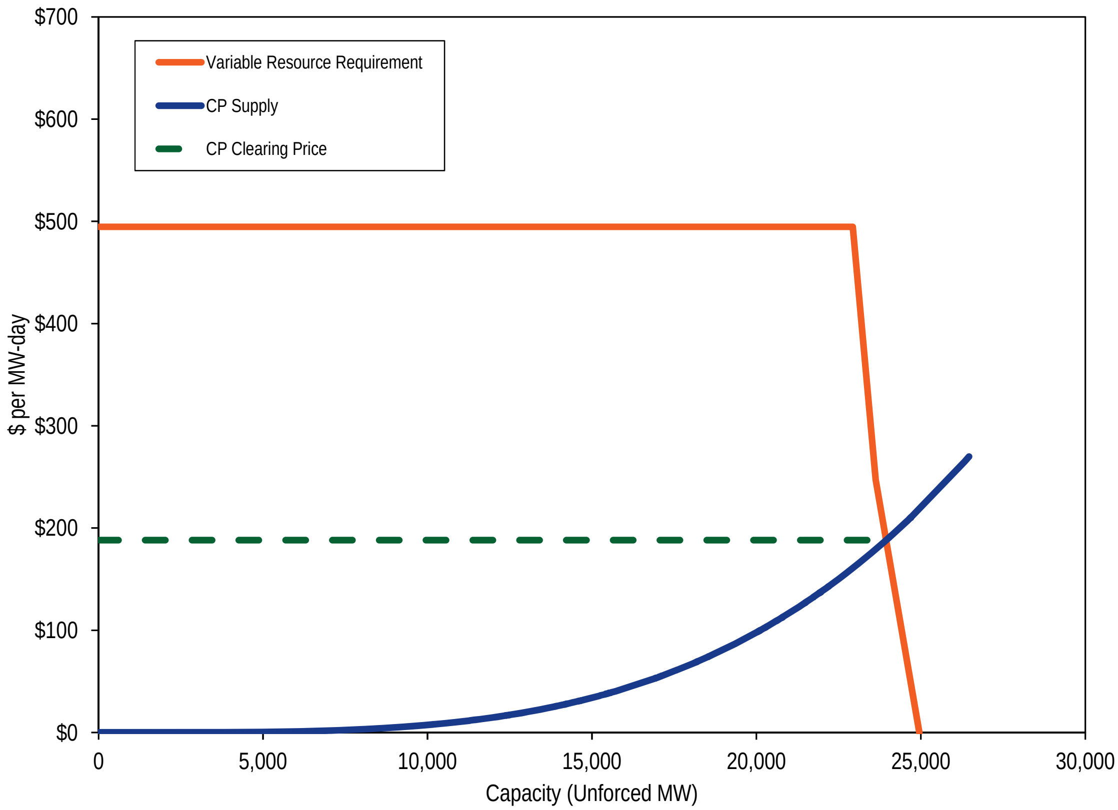
141 Unoffered DR and EE MW include PJM approved DR and EE plans that were not offered in the auction.

Table and Figures for ComEd LDA

Table 48 ComEd LDA offer statistics: 2020/2021 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	26,067.5	25,429.4		
DR capacity	1,839.5	2,003.6		
EE capacity	750.8	817.8		
Generation winter capacity	123.3	123.3		
Total internal ComEd LDA capacity	28,781.1	28,374.1		
FRR	(30.0)	(30.0)		
Imports	0.0	0.0		
RPM capacity	28,751.1	28,344.1		
Exports	(544.4)	(537.9)		
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	(225.6)	(225.6)		
Unoffered Capacity Storage Resources	0.0	0.0		
Unoffered generation winter capacity	0.0	0.0		
Unoffered DR and EE	(439.4)	(479.3)		
Available	27,541.7	27,101.3	100.0%	100.0%
Generation offered	25,390.8	24,759.2	92.2%	91.4%
DR offered	1,485.2	1,617.4	5.4%	6.0%
EE offered	665.6	724.7	2.4%	2.7%
Total offered	27,541.7	27,101.3	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%

Figure 5 ComEd LDA market supply/demand curves: 2020/2021 RPM Base Residual Auction[142]



DEOK LDA Market Results

Table 49 shows total DEOK LDA offer data for the 2020/2021 RPM Base Residual Auction. Total internal DEOK LDA unforced capacity, excluding generation winter capacity, of 4,178.5 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 17, DEOK LDA unforced internal capacity increased 199.4 MW from 3,979.1 MW in the 2019/2020 BRA as a result of net generation capacity modifications (1.8 MW), net DR modifications (102.4 MW), and net EE modifications (50.9 MW), the EFORd effect due to lower sell offer EFORds (44.3 MW), and the DR and EE effect due to a higher Load Management UCAP conversion factor (0.0 MW). As shown in Table 19, total internal DEOK unforced winter capacity increased by 0.0 MW for November through April of the 2020/2021 Delivery Year.

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142 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.[143] Total internal DEOK LDA capacity was reduced by FRR commitments of 982.0 MW, resulting in DEOK LDA RPM capacity of 3,196.5 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 61.4 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 3,135.1 MW.[144] 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 2020/2021 BRA. Of the 2,430.3 MW cleared in DEOK LDA, 1,500.5 MW were cleared in the RTO before DEOK LDA became constrained. Once the constraint was binding, based on the 5,072.0 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, 929.8 MW cleared, which resulted in a clearing price for Capacity Performance Resources of $130.00 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 14, the 2,364.5 MW of cleared and make whole and generation and DR for DEOK LDA and 5,072.0 MW CETL resulted in a net excess of 334.2 MW.

143 "PJM Manual 18: PJM Capacity Market," Rev. (April 27, 2017) at 17.

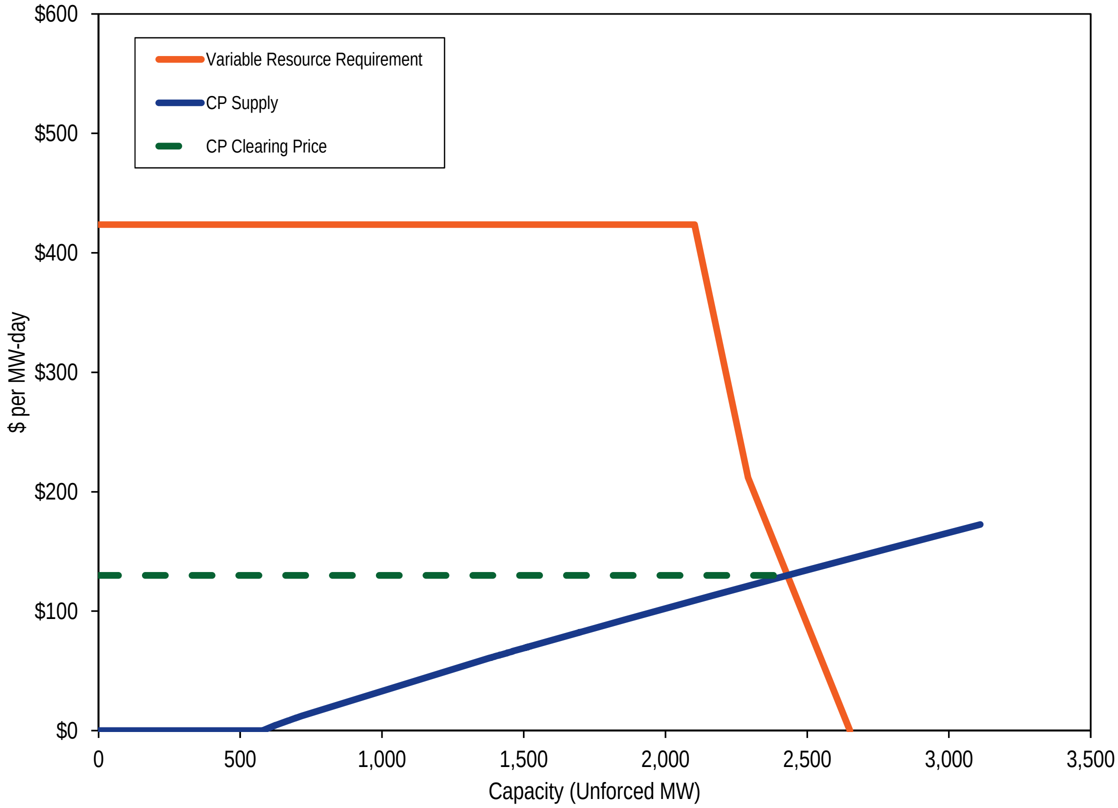
144 Unoffered DR and EE MW include PJM approved DR and EE plans that were not offered in the auction.

Table and Figure for DEOK LDA

Table 49 DEOK LDA offer statistics: 2020/2021 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	4,176.2	3,869.6		
DR capacity	219.7	239.1		
EE capacity	64.2	69.8		
Generation winter capacity	0.0	0.0		
Total internal DEOK LDA capacity	4,460.1	4,178.5		
FRR	(1,072.0)	(982.0)		
Imports	0.0	0.0		
RPM capacity	3,388.1	3,196.5		
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	(55.9)	(61.4)		
Available	3,332.2	3,135.1	100.0%	100.0%
Generation offered	3,114.2	2,898.5	93.5%	92.5%
DR offered	157.0	170.3	4.7%	5.4%
EE offered	61.1	66.4	1.8%	2.1%
Total offered	3,332.2	3,135.1	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%

Figure 6 DEOK LDA market supply/demand curves: 2020/2021 RPM Base Residual Auction[145]



145 The VRR curve is reduced by the CETL.

Attachment A

Clearing Algorithm for RPM Base Residual Auction

The actual 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.[146] 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 co-optimizes 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

[146] OATT Attachment DD § 5.12(a).

equilibrium point is reached. The method preserves the mixed integer feature of the optimization problem while allowing for incorporation of the resource constraints. 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 Resources 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. If any such inflexible offers are marginal or close to marginal, the PJM's RPM algorithm relaxes the minimum bound on those offers and re-solves the optimization, thus allowing those offers to clear below the specified lower bound. In the BRA, any resource that cleared at a MW level below the specified minimum level receives a make whole payment for the difference between the minimum bound and the unconstrained cleared MW, at the clearing price. However, the PJM approach does not consider the additional cost of make whole payments as part of the overall 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 a make whole payment. In the MMU's approach, the RPM algorithm explicitly compares solutions with make whole against solutions without make whole 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 2020/2021 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 within 0.01 percent of the corresponding 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 PS-NORTH LDA can satisfy the reliability requirement of PS-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 PS-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 PS-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.

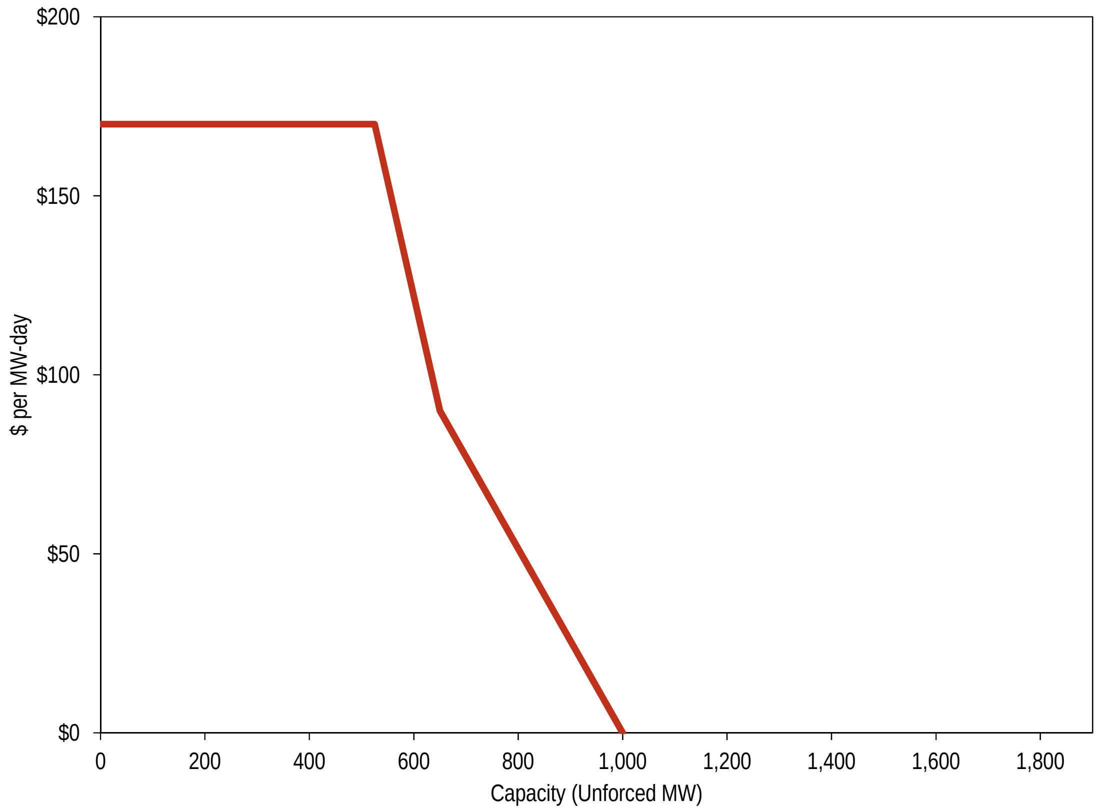
The MMU recommends improving the RPM solution method related to make whole payments. The MMU recommends changing the RPM solution method to explicitly incorporate the cost of make whole payments in the objective function.

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 7 and Figure 8 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.[147]

Figure 7 Variable resource requirement curve: child LDA



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

Figure 8 Nested variable resource requirement curve: parent LDA

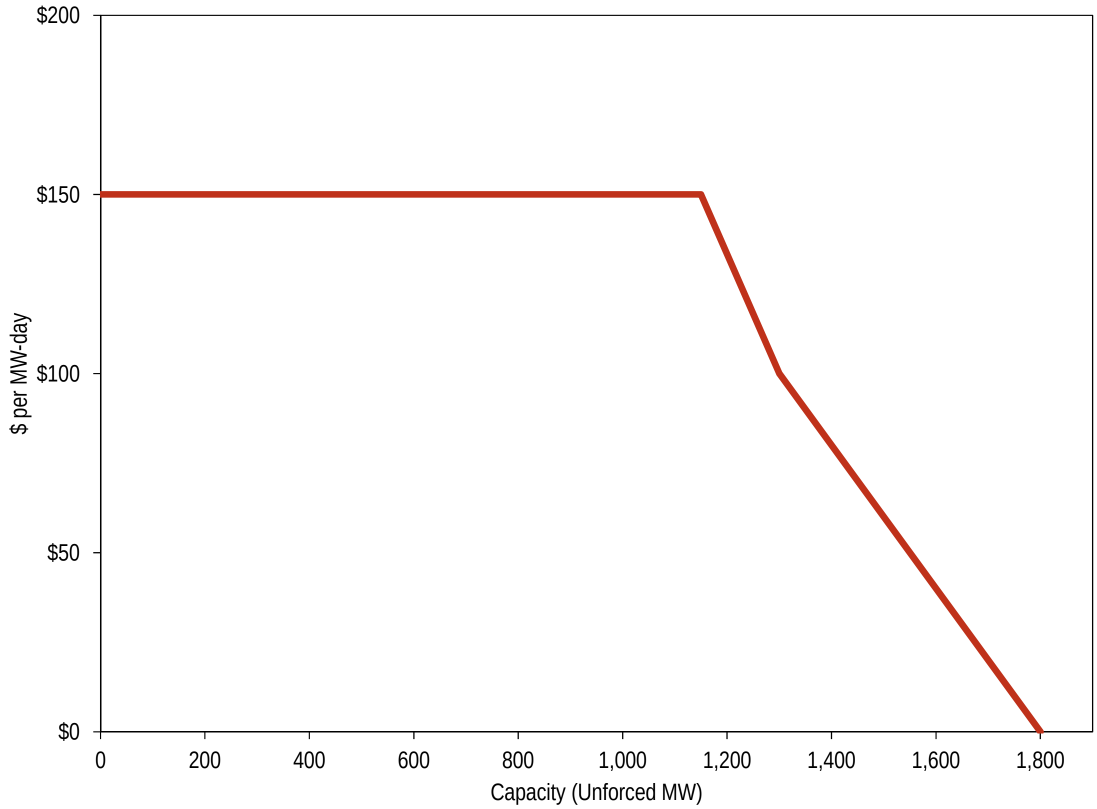


Figure 9 and Figure 10 illustrate the solution for the first scenario. Only 189.1 MW of the available 300 MW CETL is utilized. Therefore the CETL constraint is non-binding and out of merit offers are not needed to meet the child LDA's Variable Resource Requirement. The marginal clearing price for both the parent and child LDA is $120.00.

Figure 9 Optimal solution for scenario 1: child LDA

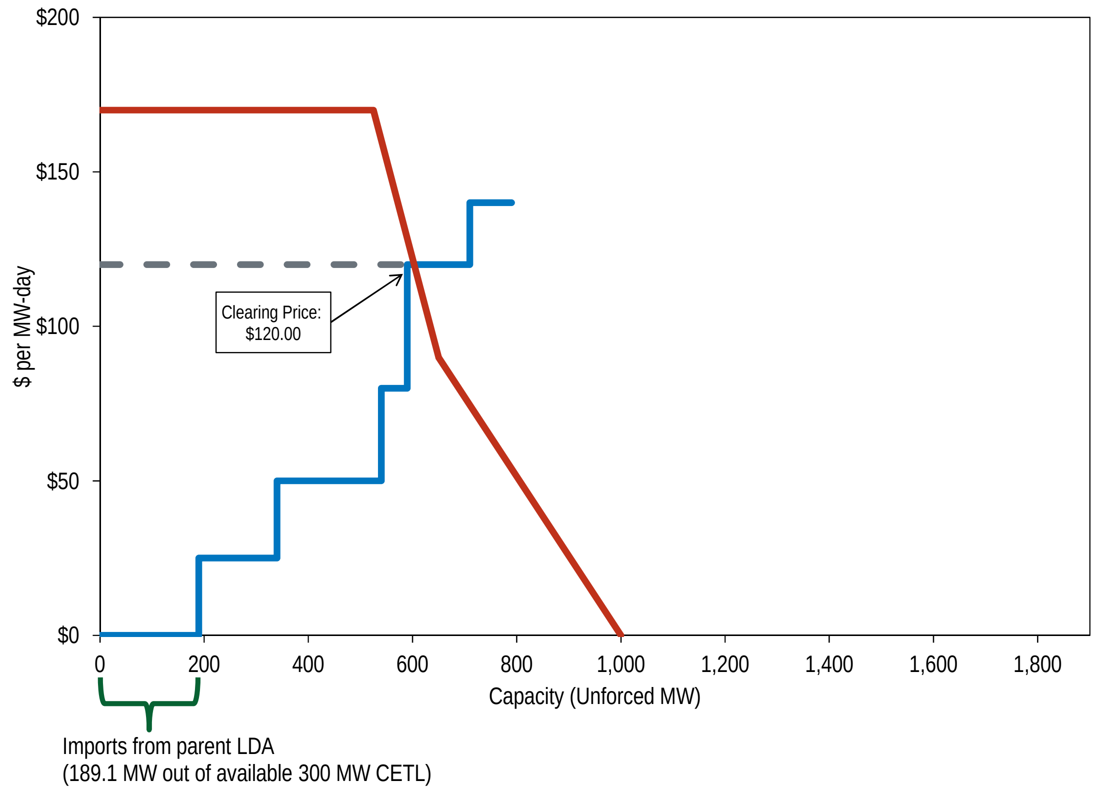


Figure 10 Optimal solution for scenario 1: Parent LDA

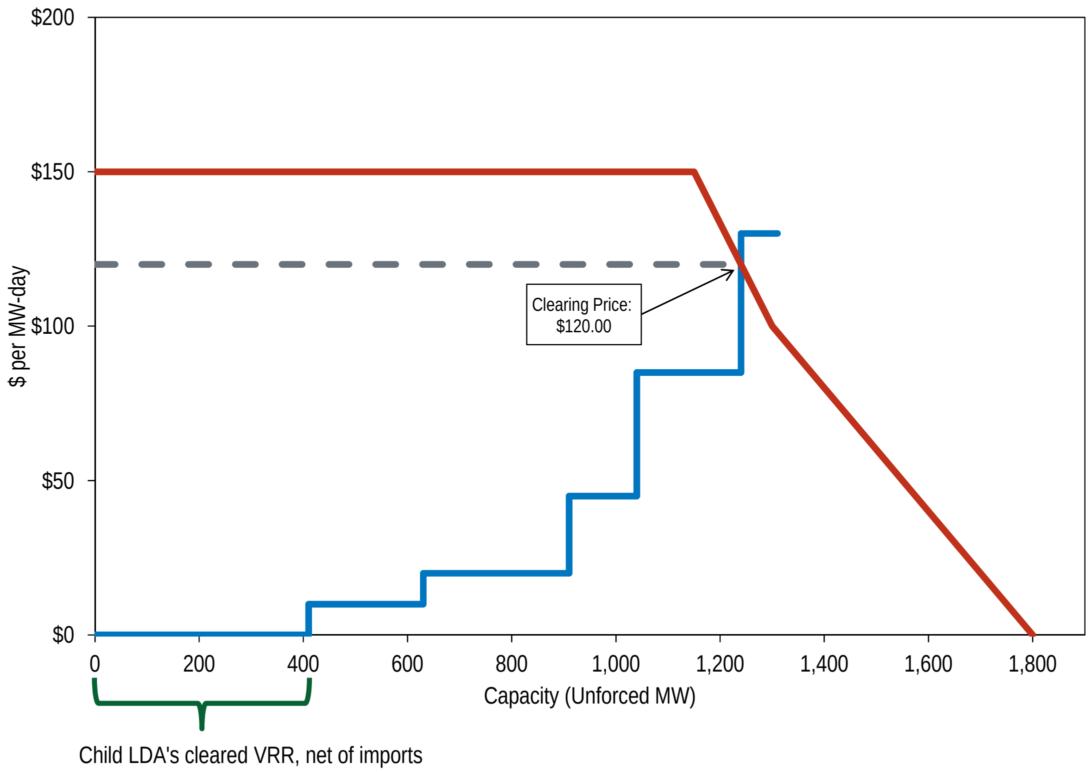


Figure 11 and Figure 12 illustrate the solution for the second scenario. The only difference between first and second scenarios is that the CETL is 150 MW in the second scenario compared to 300 MW in the first scenario. The solution shows that the entire 150 MW available is utilized by the child LDA 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 11 Optimal solution for scenario 2: Child LDA

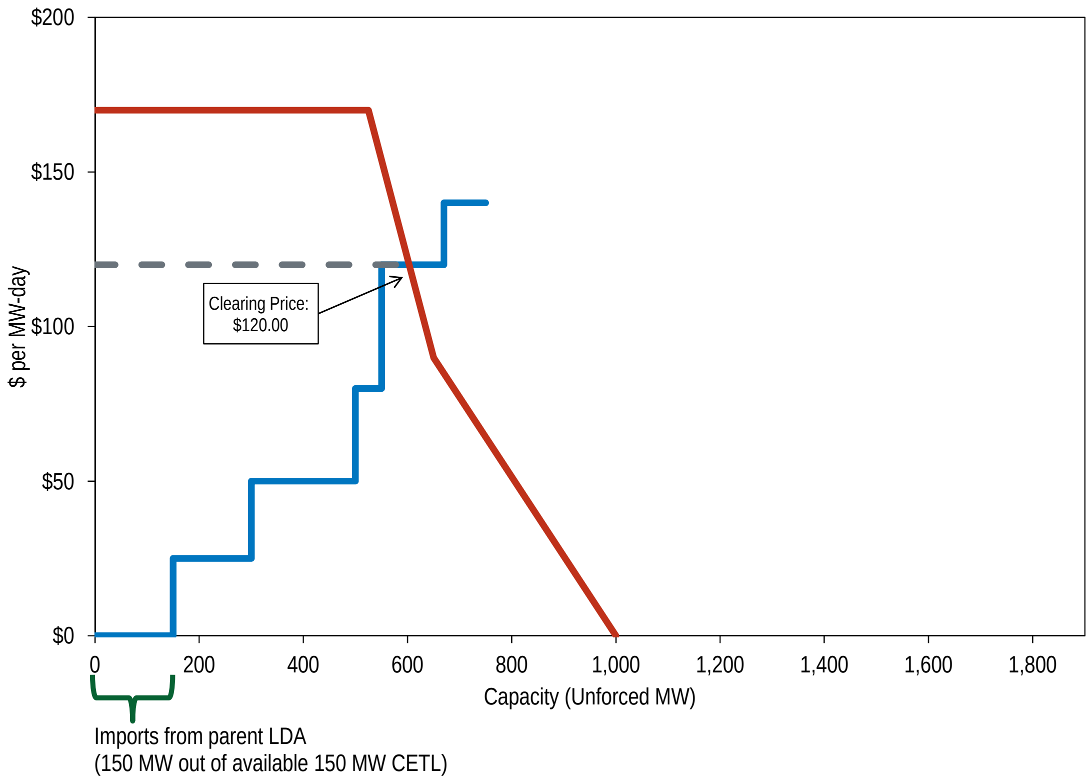
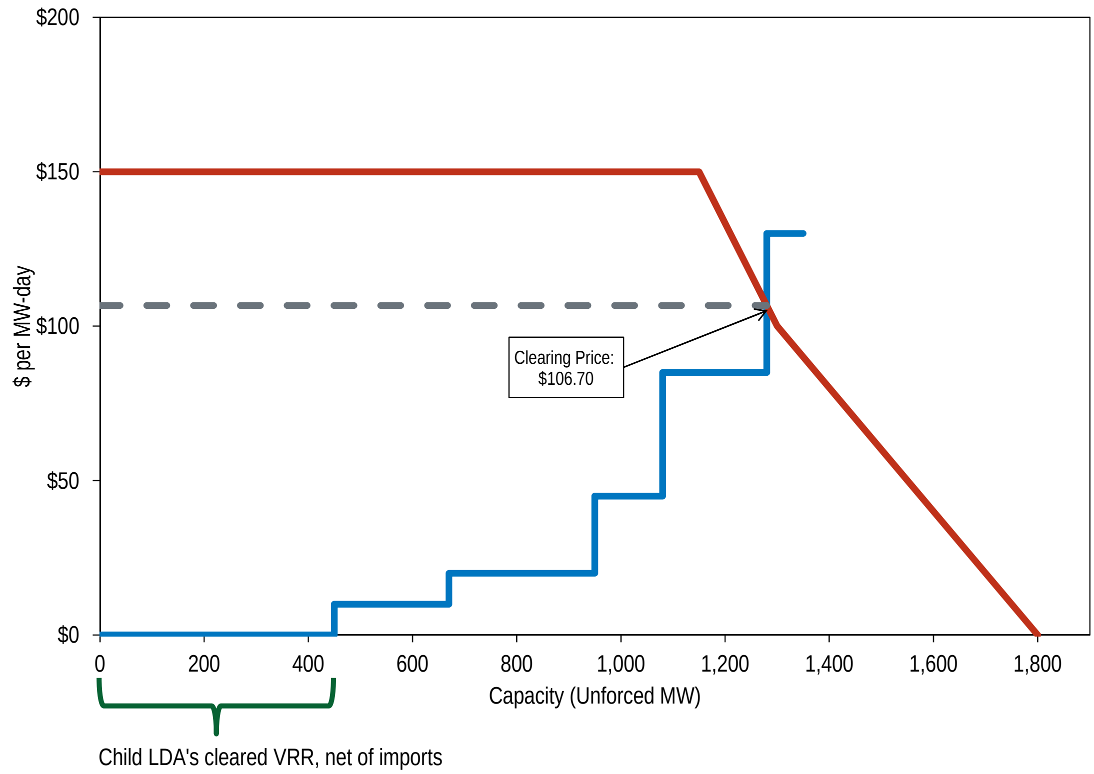


Figure 12 Optimal solution for scenario 2: Parent LDA



Attachment B

Competitive offer for a Capacity Performance resource in PJM

This attachment describes the mathematics of the calculation of a competitive capacity performance resource offer in PJM.

Definitions

R^c – net revenue for a resource with a capacity commitment

R^{nc} – net revenue for a resource without a capacity commitment that sells energy and ancillary services

A_i = (MWh_i/UCAP), availability during performance assessment hour i

$\bar{A}$ - average availability across all performance assessment hours defined as $\sum_{i=1}^{H} MWh_i/(H \times UCAP)$

B_i – balancing ratio during performance assessment hour i, ratio of total load and reserve requirement during the hour to total committed UCAP.

$\bar{B}$ – average balancing ratio across all performance assessment hours in a delivery year

H – Expected value of total number of performance assessment hours in a delivery year

$CPBR_i$ – capacity performance bonus rate for hour i in ($ per MWh), varies by hour

CPBR = average capacity performance bonus rate over all performance assessment hours in a delivery year, calculated as $\sum_{i=1}^{H}(CPBR_i \times A_i)/(H \times \bar{A})$

PPR – nonperformance charge rate ($ per MWh; Net CONE in $ per ICAP MW-year divided by 30, fixed for the delivery year for a particular Net CONE area)

ACR – Net ACR (net going forward costs) for the resource on a per MW UCAP basis, not including any risk premium.

p – Offer price in RPM on a $ per MW-year UCAP basis

Competitive Offer for an underperforming resource

If a resource is expected to underperform i.e., when expected $A_i < B_i$ for all PAH:

The net revenue for a resource that has a capacity commitment, R^c, is calculated as:

$$R^c = UCAP \times [p + PPR \times H \times (\bar{A} - \bar{B})] - UCAP \times ACR \quad (1)$$

This can be summarized as the MW of capacity multiplied by the capacity clearing price net of performance penalties less the annual avoidable costs of operating the unit.

The net revenue for that same resource that does not have a capacity commitment but participates in the energy and ancillary services markets and earns capacity bonus performance payments, R^{nc}, is calculated as:

$$R^{nc} = UCAP \times \left[\sum_{i=1}^{H}(CPBR_i \times A_i)\right] - UCAP \times ACR \tag{2}$$

This can be summarized as the MW of capacity multiplied by the bonus payments less the annual avoidable costs of operating the unit.

In equation (2) since the resource does not have a capacity performance obligation, the resource earns capacity bonus performance payments for all of its energy and reserves during performance assessment hours.

Low ACR case

If $R^{nc} \geq 0$, a resource is expected to make enough revenues to cover net going forward costs without a capacity commitment and has the opportunity to be profitable as an energy only resource in the CP design.

$$if\ ACR \leq \sum_{i=1}^{H}(CPBR_i \times A_i)$$

$$or\ ACR \leq CPBR \times H \times \bar{A}$$

In order for such a resource to have an incentive to take on the obligation to be a capacity resource under the CP design, the expected revenue with the capacity performance obligation must be greater than or equal to the expected revenue as an energy only resource, or $R^c \geq R^{nc}$.

Taking on a capacity obligation is profitable and competitive if: $R^c - R^{nc} \geq 0$. R^c and R^{nc} are defined in equation (1) and equation (2).

Thus, the competitive offer and therefore the expected equilibrium clearing price in RPM equals a value of p such that equation (1) minus equation (2) is greater than or equal to zero:

$$p \geq \left[\sum_{i=1}^{H} CPBR_i \times (A_i)\right] - PPR \times H \times (\bar{A} - \bar{B})$$

$$or, p \geq\ PPR \times H \times \bar{B} + \left[\sum_{i=1}^{H} CPBR_i \times (A_i)\right] - PPR \times H \times \bar{A}$$

Using the weighted average capacity performance bonus rate,

$$p \geq\ PPR \times H \times \bar{B} + CPBR \times H \times \bar{A} - PPR \times H \times \bar{A}$$

Therefore the competitive offer is:

$$p =\ CPBR \times H \times \bar{A} + PPR \times H \times (\bar{B} - \bar{A}) \qquad (3)$$

Equation (3) is the competitive offer formula for a low ACR resource with $A_i < B_i$ for all PAH. The competitive offer for a low ACR resource equals the expected bonus payments less the expected nonperformance charges.

Using PJM's formula for PPR as Net CONE divided by 30, the competitive offer is:

$$p =\ CPBR \times H \times \bar{A} + \left(\frac{Net\ CONE}{30}\right) \times H \times (\bar{B} - \bar{A}) \qquad (4)$$

If (i) the capacity performance bonus rate is assumed to be equal to the capacity nonperformance charge rate and, (ii) the number of expected performance hours is expected to be 30, this is identical to:

$$p =\ Net\ CONE \times \bar{B} \qquad (5)$$

These are the assumptions made in the PJM filing and result in the definition of the competitive offer cap in the PJM filing.

In fact, the actual capacity performance bonus rate (CPBR) will depend on the level of nonperformance charges collected from underperforming resources during each performance assessment hour. The maximum value of CPBR is the nonperformance charge rate, PPR, which occurs when no resource is exempted for under performance for any reason. If resources are exempted for under performance, the CPBR would decrease and the competitive offer would decrease because the value of being an energy only resource and relying solely on bonus payments would decrease as the value of the bonus payments decreases.

High ACR case

If $R^{nc} < 0$, a resource is not expected to make enough revenues to cover net going forward costs without a capacity payment.

$$if\ ACR > \left[\sum_{i=1}^{H}(CPBR_i \times A_i)\right]$$

$$or\ ACR > CPBR \times H \times \bar{A}$$

In order for such a resource to have an incentive to take on the obligation to be a capacity resource under the CP design, the expected revenue from the capacity payment and any bonus payments must be enough to cover all the costs of the unit including ACR and any capacity nonperformance charges. (The definition of an underperforming resource means that $A_i < B_i$ for all PAH and that the resource is expected to incur net nonperformance charges if it has a capacity performance obligation.)

If taking on a capacity obligation is to be profitable and competitive: $R^c \geq 0$.

From equation (1):

$$UCAP \times [p + \ PPR \times H \times (\bar{A} - \bar{B})] - UCAP \times ACR \geq 0$$

$$or, p \geq ACR + PPR \times H \times (\bar{B} - \bar{A})$$

The competitive offer is:

$$p = ACR + PPR \times H \times (\bar{B} - \bar{A}) \tag{6}$$

The competitive offer for a High ACR unit equals avoidable costs plus expected nonperformance charges.

Comparing equation (3) (Low ACR unit competitive offer) and equation (6) (High ACR unit competitive offer), there is a common component of $PPR \times H \times (\bar{B} - \bar{A})$ in both equations. For a unit to be High ACR, $ACR > CPBR \times H \times \bar{A}$. Comparing equations (3) and (6) and the assumption for a High ACR unit, the High ACR unit competitive offer from equation (6) is always greater than the Low ACR unit competitive offer from equation (3).

Competitive Offer for an overperforming resource

If a resource is expected to overperform i.e., when expected $A_i > B_i$ for all PAH:

The total net revenue for a resource that has a capacity commitment, R^c, is calculated as:

$$R^c = UCAP \times p + UCAP \times \left[\sum_{i=1}^{H} CPBR_i \times (A_i - B_i)\right] - UCAP \times ACR \tag{7}$$

This can be summarized as the MW of capacity multiplied by the capacity clearing price plus performance bonuses less the annual avoidable costs of operating the unit.

The total net revenue for that same resource that does not have a capacity commitment but participates in the energy and ancillary services markets and earns capacity bonus performance payments, R^{nc}, is calculated as:

$$R^{nc} = UCAP \times \left[\sum_{i=1}^{H}(CPBR_i \times A_i)\right] - UCAP \times ACR \quad (8)$$

This can be summarized as the MW of capacity multiplied by the bonus payments less the annual avoidable costs of operating the unit.

In equation (8) since the resource does not have a capacity performance obligation, the resource earns capacity bonus performance payments for all of its energy and reserves during performance assessment hours.

Low ACR case

If $R^{nc} \geq 0$, a resource is expected to make enough revenues to cover net going forward costs without a capacity commitment and has the opportunity to be profitable as an energy only resource in the CP design.

$$if\ ACR \leq \sum_{i=1}^{H}(CPBR_i \times A_i)$$

$$or\ ACR \leq CPBR \times H \times \bar{A}$$

In order for such a resource to have an incentive to take on the obligation to be a capacity resource under the CP design, the expected revenue with the capacity performance obligation must be greater than or equal to the expected revenue as an energy only resource, or $R^c \geq R^{nc}$.

Taking on a capacity obligation is profitable and competitive if: $R^c - R^{nc} \geq 0$. R^c and R^{nc} are defined in equation (7) and equation (8).

Thus, the competitive offer and therefore the expected equilibrium clearing price in RPM equals a value of p such that equation (7) minus equation (8) is greater than or equal to zero:

$$p \geq \left[\sum_{i=1}^{H} CPBR_i \times (B_i)\right]$$

$$or, p \geq CPBR \times H \times \bar{B} \quad (9)$$

Equation (9) is the competitive offer formula for a low ACR resource with $A_i > B_i$ for all PAH.

If (i) the capacity performance bonus rate is assumed to be equal to the capacity nonperformance charge rate (Net CONE divided by 30) and, (ii) the number of expected performance hours is expected to be 30, this is identical to:

$$p = \ Net\ CONE \times \bar{B} \tag{10}$$

These are the assumptions made in the PJM filing and result in the definition of the competitive offer cap in the PJM filing.

High ACR case

If $R^{nc} < 0$, a resource is not expected to make enough revenues to cover net going forward costs without a capacity payment.

$$if\ ACR > \left[\sum_{i=1}^{H} (CPBR_i \times A_i)\right]$$

$$or\ ACR > CPBR \times H \times \bar{A}$$

In order for such a resource to have an incentive to take on the obligation to be a capacity resource under the CP design, the expected revenue from the capacity payment and any bonus payments must be enough to cover all the costs of the unit including ACR. (The definition of an overperforming resource means that $A_i > B_i$ for all PAH and that the resource is expected to receive capacity performance bonus revenues.)

If taking on a capacity obligation is to be profitable and competitive: $R^c \geq 0$.

From equation (7):

$$UCAP \times p + UCAP \times \left[\sum_{i=1}^{H} CPBR_i \times (A_i - B_i)\right] - UCAP \times ACR \geq 0$$

$$or, p \geq ACR + CPBR \times H \times (\bar{B} - \bar{A})$$

The competitive offer is:

$$p = ACR + CPBR \times H \times (\bar{B} - \bar{A}) \tag{11}$$

The competitive offer for a High ACR unit equals avoidable costs net of expected bonus performance revenues.

The assumption that makes a unit High ACR is, $ACR > CPBR \times H \times \bar{A}$. Comparing equations (9) and (11) and the assumption for a High ACR unit, the High ACR unit competitive offer from equation (11) is always greater than the Low ACR unit competitive offer from equation (9).

If the capacity performance bonus rate is equal to the capacity nonperformance charge rate, the competitive offer for a Low ACR unit is equal to $PPR \times H \times \bar{B}$ regardless of the performance of the unit and the competitive offer for a High ACR unit is equal to $ACR + PPR \times H \times (\bar{B} - \bar{A})$ regardless of the performance of the unit.