Monitoring Analytics

Analysis of the 2021/2022 RPM Base Residual Auction: Revised

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 fifteenth Reliability Pricing Model (RPM) Base Residual Auction (BRA) (for the 2021/2022 Delivery Year) which was held from May 10 to 16, 2018, 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 Capacity Emergency Transfer Limits (CETL); the PSEG LDA CETL; the forecast peak load; VRR curve definition; Demand Resources (DR) and Energy Efficiency (EE) resources; seasonal offers and seasonal matching; capacity imports; Price Responsive Demand (PRD); the EE add back mechanism; offers for nuclear resources; and noncompetitive offers by some generation resources.[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, provided the market sets appropriate price signals to reflect the availability of excess supply. The demand for capacity includes expected peak load plus a reserve margin, and points on the demand curve, called the Variable Resource Requirement (VRR) curve, exceed peak load plus the reserve margin. 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

[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.

capacity than the difference between supply and demand either in aggregate or for a local market is jointly pivotal and therefore has structural market power.

The 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. Issues with the definition of the offer caps in the 2021/2022 BRA resulted in noncompetitive offers and a noncompetitive outcome.

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 performance assessment intervals (PAI), 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 under defined assumptions.[2] Those assumptions include: there are expected PAI; the number of PAI used in the calculation of the nonperformance charge rate is the same as the expected PAI. Those assumptions were not correct for the 2021/2022 BRA and net CONE times B was not the correct offer cap as a result.

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).

The MMU verified the reasonableness of cost data and calculated the derived offer caps based on submitted data for resources that submitted unit specific data; calculated unit net revenues; verified that CP offer caps for low ACR units did not exceed net CONE times B; evaluated CP offer caps for high ACR units including any risk adders; reviewed Minimum Offer Price Rule (MOPR) unit specific exception 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 Rates (EFORds); reviewed requests for alternate maximum EFORds; reviewed documentation for Intermittent Resources and Capacity Storage Resources to support CP eligibility; verified clearing prices based on the supply and 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, EMAAC, PSEG, ATSI, ComEd, and BGE RPM markets) failed the three pivotal supplier test. The result was that offer caps were applied to all sell offers for Existing Generation Capacity Resources when the Capacity Market Seller did not pass the test, the submitted sell offer exceeded the tariff defined offer cap, and the submitted sell offer, absent mitigation, would have resulted in a higher market clearing price.[4] [5] The offer caps are designed to reflect the marginal cost of capacity but the offer cap did not reflect the marginal cost of capacity in this BRA.

Based on the data and this review, the MMU concludes that the results of the 2021/2022 RPM Base Residual Auction were not competitive as a result of economic withholding by resources that used offers that were consistent with the net CONE times B offer cap but not consistent with competitive offers based on the correctly calculated offer cap. An accurate default offer cap for the 2021/2022 BRA can be calculated using an updated estimate for the expected number of PAI. The current assumption of 360 intervals, or 30

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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).

hours, that the net CONE times B offer cap is based on, is not aligned with the last three years of history of emergency actions in the PJM energy market, and does not reflect the observed capacity reserve margins. If the expected number of performance assessment intervals (H) is updated to a smaller number, say 60 intervals (5 hours) in line with the lower expectation of emergency events, using the tariff defined nonperformance charge rate of net CONE divided by 30, the default offer cap can be calculated as one-sixth of net CONE times B. If a resource's net ACR is greater than the updated offer cap, the competitive offer is net ACR, adjusted with any CP bonus payments or nonperformance charges.[6]

The result of not applying market power mitigation rules to generation resources that do not, absent mitigation, increase the market clearing price, would have no impact on the clearing prices but would affect seasonal make whole payments paid to seasonal offers. The result would be an exercise of market power as a result of a failure of the rules. 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 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 as close to full substitutes for internal, physical capacity resources as possible. The MMU had recommended that the definition of demand side resources be modified in order to ensure that such resources are full substitutes for and provide the same value in the Capacity Market as generation resources. 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 2.5 percent offset was implemented to permit DR to clear in Incremental Auctions (IAs). 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

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6 *See* Attachment B.

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 through 2021/2022 BRAs, 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. This conclusion applies to both nonfirm and firm imports.

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.[7] The FERC approved approach, used in the 2021/2022 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.[8] 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 offer caps that incorporated net revenues would have lower net revenues and would be greater than or equal to the offer caps calculated under the MMU approach.

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,

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7 See 155 FERC ¶ 61,281 (2016).

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

including planned generation, demand resources and imports.[9] [10] 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.[11] [12] The result of reflecting the actual flexibility is 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

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

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

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

12 See the *2017 State of the Market Report for PJM*, Vol. 2, Section 5, Capacity.

assumptions.[13] 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.[14]

Capacity market sellers are allowed to offer up to 10 sell offer segments for a resource and, for annual resources, specify a minimum MW quantity for every segment. The capacity market rules do not require the segments to be aligned with the physical operating attributes of the underlying capacity resource. In a competitive capacity market, there is no valid economic reason for capacity market sellers to specify a minimum MW quantity greater than 0 MW (inflexible sell offer segment) when offering a resource in multiple segments. A valid economic argument could be made for specifying a minimum MW quantity greater than 0 MW if the resource were offered as a single segment, representing one unit. The MMU recommends that capacity market sellers be required to request the use of minimum MW quantities greater than 0 MW (inflexible sell offer segments) and that the requests should only be permitted for defined physical reasons.

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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13 *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).

14 Comments of the Independent Market Monitor for PJM, Docket No. EL18-169 (June 20, 2018).

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 PSEG North LDA can satisfy the reliability requirement of PSEG North, PSEG, EMAAC, MAAC and RTO. However, the LDA demand (VRR) curves are defined such that, in the optimization, any resource that satisfies the requirement of a higher level LDA yields a larger consumer surplus than clearing that resource in a lower level LDA. For example, a capacity resource located in the child LDA PSEG North always results in a higher or equal consumer surplus if it clears to meet the parent LDA PSEG's requirement, instead of clearing to satisfy PSEG North's requirement. 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, the clearing process requires iteratively solving a series of optimization models to ensure that the requirements of child LDAs are satisfied before the requirements of parent LDAs.[15] With such iterative solving, the clearing process would produce implausible outcomes such as lower prices from a reduction in supply.

The MMU recommends improving the RPM solution method related to make whole payments.[16] 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

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15 For more details on the clearing process, see Attachment A.

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

implementation of the EE add back mechanism should be modified to ensure that market clearing prices are not affected.

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.[17] 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.

The MMU recommends that when expected PAIs (H) and balancing ratio (B) are not the same as the assumed levels used to calculate the default market seller offer cap of net CONE times B, the offer cap be recalculated for each BRA using the fundamental economic logic for the competitive offer of a CP resource. The MMU recommends that if the H used to calculate the Nonperformance Charge Rate is not the same as the expected number of H, the offer cap be recalculated for each BRA using both values of H separately and the fundamental economic logic for the competitive offer of a CP resource. The MMU recommends that PJM either use the last three years of history or develop a forward looking estimate for the expected number of Performance Assessment Intervals (H) to use in calculating the NonpPerformance Charge Rate. The MMU recommends that PJM either use the last three years of history or develop a forward looking estimate for the Balancing Ratio (B) during PAIs to use in calculating the default offer cap. Both H and B parameters should be included in the annual review of planning parameters for the Base Residual Auction, and should incorporate the actual observed reserve margins, and other assumptions similar to the annual IRM study.

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 10 and Table 11, the 160,795.3 MW of cleared and make whole generation and DR for the entire

[17] OATT Attachment DD § 6.5.

RTO, resulted in a reserve margin of 22.0 percent and a net excess of 8,190.3 MW over the reliability requirement adjusted for FRR and PRD of 152,605.0 MW.[18] [19] Inclusion of cleared EE Resources in the calculations on the supply side and as an add back on the demand side resulted in a calculated reserve margin of 21.1 percent and a net excess of 7,431.8 MW over the reliability requirement adjusted for FRR and PRD of 152,605.0 MW. In the 2021/2022 BRA, the reserve margin calculation including EE Resources was 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.

Table 1 and Table 2 summarize the sensitivity analyses.

The increase in the ComEd CETL of 1,510.0 MW, or 37.2 percent, from the 2020/2021 level to the 2021/2022 level had a significant impact on the auction results. The results of the scenario show that the ComEd price for the 2021/2022 RPM Base Residual Auction was higher than it would have been if the CETL had remained at the lower 2020/2021 CETL value. This counter intuitive price impact was a result of the interaction of the supply offers and the demand curve. Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If the 2020/2021 CETL value for ComEd had been used in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $8,320,327,063, a decrease of $980,550,043, or 10.5 percent, compared to the actual results. From another perspective, the use of the 2021/2022 CETL value for ComEd resulted in a 11.8 percent increase in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been using the 2020/2021 CETL value for ComEd. (Scenario 1)

PJM introduced updates to the PJM RTEP and corrections to the CETL calculations in August 2017. The updates to the planning process stem from the termination of the ConEd Wheel Agreement. The updates included 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

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[18] The 22.0 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.

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

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 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.

PJM included power flows associated with capacity imports and exports secured with firm transmission from neighboring regions in calculating CETL values between LDAs. To approximate the impact of power flows associated with imports from New York ISO, a sensitivity with a 200.0 MW reduction in the CETL value for PSEG LDA was used.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If the PSEG CETL value had been 200 MW lower than the PSEG CETL value used for the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $9,306,030,179, an increase of $5,153,073, or 0.1 percent, compared to the actual results. From another perspective, the PSEG CETL value used for the 2021/2022 RPM Base Residual Auction resulted in a 0.1 percent decrease in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been had the PSEG CETL value been 200 MW lower. (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 2014/2015 through 2018/2019 delivery years shows that the peak load forecast for the Third Incremental Auction has been on average 5.8 percent lower than the peak load forecast for the corresponding Base Residual Auction. If the peak load forecast for the 2021/2022 RPM Base Residual Auction had been 5.8 percent lower and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $6,510,513,224, a decrease of $2,790,363,882, or 30.0 percent, compared to the actual results. From another perspective, using PJM's peak load forecast for the 2021/2022 Base Residual Auction resulted in a 42.9 percent increase in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what revenues would have been using a load forecast that is 5.8 percent below the PJM peak load forecast. (Scenario 3)

PJM adjusted the VRR curve to offset certain low probability risks by shifting the VRR one percent to the right, thereby increasing demand. The shift was recommended by the Brattle Group to lower the probability of under procuring capacity in the event of a supply or demand shock, or underestimating net CONE.[20] Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If a one percent rightward shift in the VRR curve had not been included in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $8,648,601,896, a decrease of $652,275,210, or 7.0 percent, compared to the actual results. From another perspective, shifting the VRR curve one percent to the right for the 2021/2022 RPM Base Residual Auction resulted in a 7.5 percent increase in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what revenues would have been had the VRR curve not been shifted to the right by one percent. (Scenario 4)

The inclusion of all sell offers for Demand Resources and Energy Efficiency resources, including annual and seasonal, 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 2021/2022 RPM Base Residual Auction were $9,300,877,106. If there had been no offers for DR or EE in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $11,030,339,776, an increase of $1,729,462,670, or 18.6 percent, compared to the actual results. From another perspective, the inclusion of Demand Resources and Energy Efficiency resources resulted in a 15.7 percent reduction in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been without any Demand Resources or Energy Efficiency resources. (Scenario 5)

The 2021/2022 RPM Base Residual Auction was the third 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 2021/2022 RPM Base Residual Auction were $9,300,877,106. If there were no offers for EE and the EE add back MW were removed in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base

[20] "Third Triennial Review of PJM's Variable Resource Requirement Curve," The Brattle Group, May 15, 2014, P. 68. The report is available at this link <http://www.pjm.com/-/media/library/reports-notices/reliability-pricing-model/20140515-brattle-2014-pjm-vrr-curve-report.ashx?la=en>.

Residual Auction would have been $8,450,275,422, a decrease of $850,601,684, or 9.1 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 10.1 percent increase in RPM revenues for the 2021/2022 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 6)

The inclusion of sell offers for Annual Demand Resources and Annual 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 2021/2022 RPM Base Residual Auction were $9,300,877,106. If there had been no offers for Annual DR or Annual EE in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $11,048,633,706, an increase of $1,747,756,600, or 18.8 percent, compared to the actual results. From another perspective, the inclusion of Annual Demand Resources and Annual Energy Efficiency Resources resulted in a 15.8 percent reduction in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been without any Annual Demand Resources or Annual Energy Efficiency resources. (Scenario 7)

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.[21] 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 Seasonal 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 2021/2022 RPM Base Residual Auction were $9,300,877,106. If there had been no offers for Seasonal DR or Seasonal EE in the 2021/2022 RPM Base Residual Auction and

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

everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $9,207,711,533, a decrease of $93,165,573, or 1.0 percent, compared to the actual results. From another perspective, the inclusion of Seasonal Demand Resources and Seasonal Energy Efficiency resources resulted in a 1.0 percent increase in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been without any Seasonal Demand Resources or Seasonal Energy Efficiency resources. (Scenario 8)

The results show that the inclusion of additional Seasonal Demand Resources and Seasonal Energy Efficiency resources caused price increases in some LDAs. One factor leading to this result is that the EE add back MW for Seasonal Energy Efficiency adjustment to the VRR curve is larger than the amount of Seasonal Energy Efficiency offers, and therefore removing the Seasonal Energy Efficiency resources had a larger impact on demand than supply. The interaction of the supply offers and the demand curve also contributed to the counter intuitive result.

The 2021/2022 RPM Base Residual Auction was the second BRA held using the Seasonal products for summer and winter capacity. The inclusion of seasonal offers (Demand Resources, Energy Efficiency Resources, and Generation Resources) had a limited impact on the auction results. Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If there had been no offers for Seasonal products in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $9,296,441,218, a decrease of $4,435,888, or 0.0 percent, compared to the actual results. From another perspective, the inclusion of Seasonal offers resulted in a 0.0 percent increase in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been without any Seasonal offers. (Scenario 9)

The results show that the inclusion of seasonal offers caused price increases in some LDAs. One factor leading to this result is that the EE add back MW for Seasonal Energy Efficiency adjustment to the VRR curve is larger than the amount of Seasonal Energy Efficiency offers, and therefore removing the Seasonal Energy Efficiency resources had a larger impact on demand than supply. The interaction of the supply offers and the demand curve also contributed to the counter intuitive result.

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 2021/2022 RPM Base Residual Auction were $9,300,877,106. If there had been no offers from Demand Resources, Energy Efficiency resources, or Seasonal resources in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been

$11,031,353,576, an increase of $1,730,476,470, or 18.6 percent, compared to the actual results. From another perspective, the inclusion of Demand Resources, Energy Efficiency resources, and Seasonal resources resulted in a 15.7 percent decrease in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been without any Demand Resources, Energy Efficiency resources, or Seasonal resources. (Scenario 10)

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 2021/2022 RPM Base Residual Auction were $9,300,877,106. If the amount of winter offers had been reduced by 50 percent in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $9,271,942,523, a decrease of $28,934,583, or 0.3 percent, compared to the actual results. From another perspective, the inclusion of all winter offers resulted in a 0.3 percent increase in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been if offers from winter resources had been reduced by 50 percent. Removing 50 percent of the winter resources from the available supply led to a lower clearing price in the ComEd LDA. (Scenario 11)

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 did not have an impact on the 2021/2022 RPM Base Residual Auction results. Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If seasonal offers were not matched with complementary seasonal offers from other LDAs in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, all LDA clearing prices and clearing amounts would have remained the same and total RPM market revenues would have remained the same at $9,300,877,106. In the 2021/2022 RPM Base Residual Auction, the proportion of low priced offers for summer in the rest of the RTO, the lowest common parent for all LDAs, substantially increased from the 2020/2021 RPM Base Residual Auction. Restricting the matching of complementary seasonal products to the LDA in which they are located deprives a resource that did not clear for a lower LDA such as PSEG to be matched with a complementary seasonal product in a higher LDA such as rest of the RTO. However, the availability of similarly lower priced offers located in the rest of RTO resulted in no difference in clearing quantities and prices when the seasonal matching was restricted to be within the same LDA where the both summer and winter resources were physically located. (Scenario 12)

The inclusion of capacity imports in the 2021/2022 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 2021/2022 RPM Base Residual Auction were $9,300,877,106. If offers for external generation were reduced by 25 percent and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $9,589,433,567, an increase of $288,556,461, or 3.1 percent, compared to the actual results. From another perspective, the impact of including all offers for external generation resources resulted in a 3.0 percent reduction in RPM revenues for the 2021/2022 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 13)

If offers for external generation were reduced by 100 percent and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $10,427,509,062, an increase of $1,126,631,956, or 12.1 percent, compared to the actual results. From another perspective, the impact of including all offers for external generation resources resulted in a 10.8 percent reduction in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been if no offers from external generation resources were included in the auction. (Scenario 13, Scenario 14, Scenario 15, Scenario 16)

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 2021/2022 RPM Base Residual Auction were $9,300,877,106. If there had been no offers from Demand Resources, Energy Efficiency resources, or Seasonal resources, and imports had been reduced by 100 percent in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $11,997,162,266, an increase of $2,696,285,160, or 29.0 percent, compared to the actual results. From another perspective, the inclusion of Demand Resources, Energy Efficiency resources, and seasonal resources and including all offers for external generation resources resulted in a 22.5 percent decrease in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been without any Demand Resources, Energy Efficiency resources, seasonal resources, or external generation resources. (Scenario 17)

Under the EE add back MW rules, the demand curve was shifted by an amount greater than the quantity of cleared EE, and the clearing price was increased as a result of the implementation of the EE 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 2021/2022 RPM Base Residual Auction would have been $8,797,549,143, a decrease of

$503,327,963, or 5.4 percent, compared to the actual results. From another perspective, the inconsistency between the EE cleared MW and the adjustment to the demand with the EE add back MW resulted in a 5.7 percent increase in RPM revenues for the 2021/2022 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 18)

The 2021/2022 RPM Base Residual Auction was the second 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 2021/2022 RPM Base Residual Auction were $9,300,877,106. If there had been no submissions from PRD providers in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $9,424,270,494, an increase of $123,393,388, or 1.3 percent, compared to the actual results. From another perspective, the inclusion of PRD resulted in a 1.3 percent reduction in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been without any PRD. (Scenario 19)

Nuclear offer behavior changed in the 2021/2022 RPM Base Residual Auction compared to prior auctions. More nuclear capacity was offered at higher sell offer prices and fewer nuclear MW cleared.[22] (See Table 21, Table 22, and Table 30) To define an upper bound on the impact of nuclear offers, a scenario setting all nuclear offers to $0 per MW-day was analyzed. It is not asserted that a $0 per MW-day sell offer is accurate for all nuclear resources. If all nuclear offers were replaced by $0 per MW-day in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $5,215,048,770, a decrease of $4,085,828,337, or 43.9 percent, compared to the actual results. From another perspective, the nuclear offers at levels exceeding $0 per MW-day resulted in a 78.3 percent increase in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been had all nuclear offers been at $0 per MW-day. (Scenario 20)

The MMU identified noncompetitive offers that had a significant impact on the 2021/2022 RPM Base Residual Auction results.

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

Some participants' offers were above the competitive level. The MMU recognizes that these market participants followed the capacity market rules by offering at less than the stated offer cap of Net CONE times B. But Net CONE times B is not a competitive offer when the expected number of performance assessment intervals is zero or a very small number and the nonperformance charge rate is defined as Net CONE/30. Under these circumstances, a competitive offer, under the logic defined in PJM's capacity performance filing, is net ACR. That is the way in which most market participants offered in this and prior capacity performance auctions.

The FERC approved PJM tariff defines the offer cap as Net CONE times B, rather than including the full logic supporting the definition of the offer cap under the capacity performance paradigm. If the tariff had defined the offer cap consistent with PJM's filing in the capacity performance matter, the offer cap would have been net ACR rather than Net CONE times B.

The PJM tariff defines the balancing ratio (B) used in the default offer cap as the average of balancing ratios during the actual performance assessment intervals that occurred during the three calendar years preceding the auction.[23] PJM did not experience any performance assessment intervals during the three year period that preceded the 2021/2022 RPM Base Residual Auction and the balancing ratio calculation was not feasible. PJM resolved the balancing ratio issue by changing the tariff to state that the balancing ratio for the 2021/2022 RPM Base Residual Auction would equal the balancing ratio value used for the 2020/2021 RPM Base Residual Auction.[24] PJM did not propose any updates to the non-performance charge rate or the default offer cap definition of net CONE times B. In doing so, PJM continued to assume an expected 30 hours, or 360 intervals, of PAIs for the 2021/2022 delivery year. This assumption is not consistent with the last three years of history of emergency actions in the PJM energy market. The correct way to account for the lack of performance assessment intervals during the three year history would have been to recognize that this means that unit specific net ACR is the offer cap under the capacity performance construct. This would have been consistent with a market participant having an expectation of a very low number of performance assessment intervals. This would have been consistent with the competitive offer

[23] OATT Attachment DD § 6.4(a).

[24] *See* PJM. "Reliability Pricing Model Offer Cap Tariff Revision for 2018 Base Residual Auction", Docket No. ER18-262 (November 7, 2017).

calculation logic that PJM filed in response to a deficiency letter issued by the Commission in the Capacity Performance docket.[25]

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If the identified noncompetitive offers had been capped at net ACR in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $8,070,050,631, a decrease of $1,230,826,475, or 13.2 percent, compared to the actual results. From another perspective, the noncompetitive offers resulted in a 15.3 percent increase in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been had the noncompetitive offers been capped at net ACR. (Scenario 21)

Tables for Results Section

Table 1 Scenario summary of RPM revenue: 2021/2022 RPM Base Residual Auction

			Scenario Impact	
Scenario	Scenario Description	RPM Revenue ($ per Delivery Year)	RPM Revenue ($ per Delivery Year)	Percent
0	Actual Results	$9,300,877,106	NA	NA
1	Decrease in the ComEd CETL	$8,320,327,063	$980,550,043	11.8%
2	PSEG CETL Adjustment	$9,306,030,179	($5,153,073)	(0.1%)
3	Reduce Load Forecast by 5.8 percent	$6,510,513,224	$2,790,363,882	42.9%
4	Inclusion of 1 percent VRR right shift	$8,648,601,896	$652,275,210	7.5%
5	Inclusion of DR/EE Offers	$11,030,339,776	($1,729,462,670)	(15.7%)
6	Inclusion of EE Offers and EE Add Back	$8,450,275,422	$850,601,684	10.1%
7	Inclusion of Annual DR/EE Offers	$11,048,633,706	($1,747,756,600)	(15.8%)
8	Inclusion of Seasonal DR/EE Offers	$9,207,711,533	$93,165,573	1.0%
9	Inclusion of Seasonal Products	$9,296,441,218	$4,435,888	0.0%
10	Inclusion of DR/EE and Seasonal Resources	$11,031,353,576	($1,730,476,470)	(15.7%)
11	Inclusion of 50 Percent of Offers from Winter Resources	$9,271,942,523	$28,934,583	0.3%
12	Inclusion of Seasonal Matching Across LDAs	$9,300,877,106	$0	0.0%
13	Inclusion of 25 Percent of Offers for External Generation	$9,589,433,567	($288,556,461)	(3.0%)
14	Inclusion of 50 Percent of Offers for External Generation	$9,994,522,907	($693,645,801)	(6.9%)
15	Inclusion of 75 Percent of Offers for External Generation	$10,350,916,800	($1,050,039,694)	(10.1%)
16	Inclusion of 100 Percent of Offers from External Generation	$10,427,509,062	($1,126,631,956)	(10.8%)
17	Inclusion of DR/EE, Seasonal Capacity and External Generation	$11,997,162,266	($2,696,285,160)	(22.5%)
18	Impact of Adjusting the VRR Curve by EE Add Back Amount that Differs from Cleared EE	$8,797,549,143	$503,327,963	5.7%
19	Inclusion of PRD	$9,424,270,494	($123,393,388)	(1.3%)
20	Impact of nonzero Nuclear Offers	$5,215,048,770	$4,085,828,337	78.3%
21	Impact of noncompetitive Offers	$8,070,050,631	$1,230,826,475	15.3%

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

Table 2 Scenario summary of cleared UCAP: 2021/2022 RPM Base Residual Auction

			Scenario Impact	
Scenario	Scenario Description	Cleared UCAP (MW)	Cleared UCAP (MW)	Percent
0	Actual Results	163,627.3	NA	NA
1	Decrease in the ComEd CETL	164,508.9	(881.6)	(0.5%)
2	PSEG CETL Adjustment	163,627.3	0.0	0.0%
3	Reduce Load Forecast by 5.8 percent	155,349.8	8,277.5	5.3%
4	Inclusion of 1 percent VRR right shift	162,646.5	980.8	0.6%
5	Inclusion of DR/EE Offers	158,125.4	5,501.9	3.5%
6	Inclusion of EE Offers and EE Add Back	160,125.8	3,501.5	2.2%
7	Inclusion of Annual DR/EE Offers	158,398.2	5,229.1	3.3%
8	Inclusion of Seasonal DR/EE Offers	163,222.5	404.8	0.2%
9	Inclusion of Seasonal Products	163,142.0	485.3	0.3%
10	Inclusion of DR/EE and Seasonal Resources	158,125.1	5,502.2	3.5%
11	Inclusion of 50 Percent of Offers from Winter Resources	163,584.9	42.4	0.0%
12	Inclusion of Seasonal Matching Across LDAs	163,627.3	0.0	0.0%
13	Inclusion of 25 Percent of Offers for External Generation	163,320.8	306.5	0.2%
14	Inclusion of 50 Percent of Offers for External Generation	162,954.3	673.0	0.4%
15	Inclusion of 75 Percent of Offers for External Generation	162,656.6	970.7	0.6%
16	Inclusion of 100 Percent of Offers from External Generation	162,571.1	1,056.2	0.6%
17	Inclusion of DR/EE, Seasonal Capacity and External Generation	157,509.1	6,118.2	3.9%
18	Impact of Adjusting the VRR Curve by EE Add Back Amount that Differs from Cleared EE	162,803.4	823.9	0.5%
19	Inclusion of PRD	164,099.0	(471.7)	(0.3%)
20	Impact of nonzero Nuclear Offers	165,844.3	(2,217.0)	(1.3%)
21	Impact of noncompetitive Offers	164,132.1	(504.8)	(0.3%)

Clearing Prices

Table 3 shows the clearing prices for Capacity Performance Resources in the 2021/2022 BRA by zone compared to the corresponding net Cost of New Entry (CONE) times (B), where B is the average of the Balancing Ratios during the Performance Assessment Intervals in the three consecutive calendar years that precede the Base Residual Auction for such Delivery Year. The clearing prices for CP Resources were less than net CONE times B for every Zone. The ratio of clearing price to net CONE times B exceeded 85 percent for two zones.

Table 3 Clearing prices and net CONE times B: 2021/2022 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	$165.70	$310.57	0.79	$243.80	($78.10)	68.0%
AEP	$140.00	$297.97	0.79	$233.91	($93.91)	59.9%
AP	$140.27	$278.10	0.79	$218.31	($78.04)	64.3%
ATSI	$171.32	$288.79	0.79	$226.70	($55.38)	75.6%
BGE	$171.86	$229.94	0.79	$180.50	($8.64)	95.2%
ComEd	$195.55	$324.08	0.79	$254.40	($58.85)	76.9%
DAY	$140.00	$294.15	0.79	$230.91	($90.91)	60.6%
DEOK	$140.00	$294.38	0.79	$231.09	($91.09)	60.6%
DLCO	$140.00	$298.94	0.79	$234.67	($94.67)	59.7%
DPL	$165.58	$282.50	0.79	$221.76	($56.18)	74.7%
Dominion	$140.00	$298.26	0.79	$234.13	($94.13)	59.8%
EKPC	$140.00	$308.82	0.79	$242.42	($102.42)	57.8%
External	$140.00	$302.63	0.79	$237.56	($97.56)	58.9%
JCPL	$165.72	$276.92	0.79	$217.38	($51.66)	76.2%
Met-Ed	$140.00	$274.82	0.79	$215.73	($75.73)	64.9%
PECO	$165.72	$282.13	0.79	$221.47	($55.75)	74.8%
PENELEC	$140.00	$201.82	0.79	$158.43	($18.43)	88.4%
PPL	$140.06	$283.01	0.79	$222.16	($82.10)	63.0%
PSEG	$192.25	$311.13	0.79	$244.24	($51.99)	78.7%
Pepco	$140.00	$268.61	0.79	$210.86	($70.86)	66.4%
RECO	$165.15	$308.45	0.79	$242.13	($76.98)	68.2%

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.[26] [27]

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

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26 158 FERC ¶ 62,220.

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

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 intervals 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.[28] 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.[29] 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.[30]

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 2021/2022 BRA, this meant that the RTO VRR curve was shifted to the right by 3,912.9 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

28 137 FERC ¶ 61,204.

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

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

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 2021/2022 BRA, the ratio in the initial solution of 3,912.9/2,832.0=1.38167373 did not exceed the applicable threshold ratio of 1.606739475. 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.[31]

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).

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,

[31] "PJM Manual 18: PJM Capacity Market," Rev. 40 (Feb. 22, 2018) at 19.

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.[32]

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 Intervals in the three consecutive calendar years that precede the Base Residual Auction for such delivery year.

Effective for the 2018/2019 and subsequent delivery years, the ACR definition includes two additional components, Avoidable Fuel Availability Expenses (AFAE) and Capacity Performance Quantifiable Risk (CPQR). AFAE is 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.

For the 2021/2022 RPM Base Residual Auction, PJM used the same balancing ratio as the 2020/2021 RPM Base Residual Auction while PJM conducts a stakeholder process to modify the balancing ratio determination.[33] There were no performance assessment intervals or emergency events in 2015 through 2017, so the balancing ratio for 2021/2022 based on the previous tariff definition would have been zero, meaning that the net CONE times B offer cap would have been $0 per MW-day and offer caps would have defaulted to net ACR. This is because without performance assessment intervals, there is no opportunity to earn capacity bonus revenues for an energy only resource, and the resource would have to take on a capacity obligation and earn capacity revenues from the auction, to meet its avoidable costs net of any energy and ancillary service revenues. The competitive offer for such a resource, and the offer cap, would be its net ACR.

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

33 Docket No. ER18-262-000.

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.

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.[34] 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.

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34 147 FERC ¶ 61,060 (2014).

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.

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

Effective May 9, 2017, enhanced pseudo tie requirements for external generation capacity resources were implemented, including a transition period with deliverability requirements for existing pseudo tie resources that has previously cleared an RPM auction.[35] The rule changes include defining coordination with other Balancing Authorities when conducting pseudo tie studies, establishing an electrical distance requirement, establishing a market-to-market flowgate test to establish limits on the number of coordinated flowgates PJM must add in order to accommodate a new pseudo-tie, a model consistency requirement, the requirement for the capacity market seller to provide written acknowledgement from the external Balancing Authority Areas that such Pseudo-Tie does not require tagging and that firm allocations associated with any coordinated flowgates applicable to the external Generation Capacity Resource under any agreed congestion management process then in effect between PJM and such Balancing Authority Area will be allocated to PJM, the requirement for the capacity market seller to obtain long-term firm point-to-point transmission service for transmission outside PJM with rollover rights and to obtain network external designated transmission service for transmission within PJM, establishing an operationally deliverable standard, and modifying the nonperformance penalty definition for external generation capacity resources to assess performance at sub-regional transmission organization granularity.

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.[36] These changes included clarifying the applicability of the must-offer requirement and the circumstances under which exemptions from the

35 161 FERC ¶ 61,197 (2017).

36 134 FERC ¶ 61,065 (2011).

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.[37] 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.[38] 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 posted on August 31, 2015, and September 9, 2015, in order to make an informed decision on retiring a resource.[39]

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.

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

38 145 FERC ¶ 61,035 (2013).

39 152 FERC ¶ 61,151 (2015).

MOPR

Effective April 12, 2011, the RPM Minimum Offer Price Rule (MOPR) was changed.[40] 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.[41]

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.[42] 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 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.

On July 7, 2017, the U.S. Court of Appeals for the District of Columbia Circuit issued an opinion that vacated FERC orders approving the then current MOPR.[43][44] In those orders,

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40 135 FERC ¶ 61,022 (2011).

41 135 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.

42 143 FERC ¶ 61,090 (2013).

43 143 FERC ¶61,090, *reh'g denied*, 153 FERC ¶61,066.

FERC had accepted a PJM filing that revised the MOPR to include a self-supply exemption and a competitive entry exemption on condition that MOPR continue to include the ability for a participant to calculate a unit specific offer. Effective December 8, 2017, the rules that were in effect prior to PJM's December 7, 2012, MOPR filing were reinstated. These changes include eliminating the Competitive Entry and Self Supply Exemptions and retaining only the Unit Specific Exception request; narrowing the region subject to MOPR from the entire RTO to only modeled LDAs; eliminating the 20.0 MW threshold for applicability; redefining the applicability criteria to exclude nuclear, coal, IGCC, hydroelectric, wind and solar facilities; modifying the duration of mitigation criteria from clearing in a prior delivery year to clearing in any delivery year; and changing the procedural deadlines.[45]

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.[46] [47] [48]

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

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44 NRG Power Marketing, LLC v FERC, No. 15-1452 (2017).

45 161 FERC ¶ 61,252 (2017) ("Remand Order").

46 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).

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

48 142 FERC ¶ 61,092 (2013).

interruption of longer than six hours, which is the maximum duration of an interruption for a Limited DR product.[49]

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 previously established Limited DR product type.[50] 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.[51] 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.[52] 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

[49] 143 FERC ¶ 61,076 (2013).

[50] 134 FERC ¶ 61,066 (2011).

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

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

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, 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. 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 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.[53] 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.[54] 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

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53 146 FERC ¶ 61,052 (2014).

54 146 FERC ¶ 61,150 (2014).

Generation Resources, Base Capacity Demand Resources, and Base Capacity Energy 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. 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.

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.

Effective with the 2020/2021 Delivery Year, credit limited offers are not available as the post auction credit rate of Capacity Performance resources is not solely a function of the resource clearing price.

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.[55] The rule required compliance by April 16, 2015, with the possibility of one year extensions being granted to individual generation owners.[56]

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.[57] 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 2021/2022 RPM Base Residual Auction: [58]

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

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55 *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).

56 *Id*. at 9465.

57 N.J.A.C. § 7:27–19.

58 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 2021/2022 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 2015 through 2017;[59]

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

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

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

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

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

- Maximum EFORd. Verified that the sell offer EFORd levels were less than or equal to the greater of the one-year EFORd or the five-year EFORd for the period ending September 30, 2017, or reviewed requests for alternate maximum EFORds;

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

- Clearing Prices. Verified that the auction clearing prices were accurate, based on submitted offers and the Variable Resource Requirement (VRR) curves;[60]

- 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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[59] Net revenue values for the 2021/2022 RPM BRA were calculated consistent with the FERC order effective at the time. *See Order on Section 206 Investigation*, 154 FERC ¶ 61,151 (2016).

[60] 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, EMAAC, PSEG, ATSI, ComEd, and BGE RPM markets failed the TPS test.[61] 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 do not, absent mitigation, increase the market clearing price would have no impact on the clearing prices in the auction but would affect seasonal make whole payments paid to seasonal offers. The result would be an exercise of market power as a result of a failure of the rules. 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.

Market power mitigation was applied to the Capacity Performance sell offers of zero generation capacity resources in the 2021/2022 RPM Base Residual Auction. All offers were less than the tariff defined offer caps or not applying the tariff defined offer cap did not increase clearing prices. But the net CONE times B offer cap under the capacity performance design, in the absence of performance assessment intervals, exceeds the competitive level.

In applying the three pivotal supplier market structure test, the relevant supply for the RTO market includes all supply from generation resources offered at less than or equal to 150 percent of the RTO clearing price resulting from offer capped offers for all supply.[62] 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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61 See the MMU *Technical Reference for PJM Markets*, at "Three Pivotal Supplier Test" for a more detailed discussion of market structure tests.

62 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.[63]

Table 4 RSI results: 2021/2022 RPM Base Residual Auction[64]

	$RSI_{1\ 1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
RTO	0.80	0.68	122	122
EMAAC	0.71	0.22	14	14
PSEG	0.20	0.01	5	5
ATSI	0.01	0.00	2	2
ComEd	0.08	0.02	5	5
BGE	0.23	0.00	3	3

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 2021/2022 RPM Base Residual Auction.[65] Market power mitigation measures are applied to Existing Generation Capacity

63 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.

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

65 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).

Resources such that the sell offer is set equal to the tariff defined offer cap when the Capacity Market Seller fails the market structure test for the auction, the submitted sell offer exceeds the tariff defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price.[66] 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 Intervals 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 2020/2021 and 2021/2022 RPM Base Residual Auctions. In all zones, the net CONE times B offer cap values increased from the 2020/2021 RPM Base Residual Auction, mainly due to lower net revenues for the 2015 through 2017 time period.

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.[67] 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.[68]

Effective for the 2018/2019 and subsequent Delivery Years, the ACR definition includes two additional components, Avoidable Fuel Availability Expenses (AFAE) and Capacity

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66 OATT Attachment DD § 6.5.

67 OATT Attachment DD § 6.8 (b).

68 OATT Attachment DD § 6.8 (a).

Performance Quantifiable Risk (CPQR).[69] AFAE is available for Capacity Performance Resources. AFAE is defined to include expenses related to fuel availability and delivery. CPQR is available for Capacity Performance Resources and, for the 2018/2019 and 2019/2020 Delivery Years, Base Capacity Resources. CPQR is defined to be the quantifiable and reasonably supported cost of mitigating the risks of nonperformance associated with submission of an offer.

The opportunity cost option allows Capacity Market Sellers to 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 6, 1,132 generation resources submitted Capacity Performance offers in the 2021/2022 RPM Base Residual Auction. The MMU calculated offer caps for eight generation resources that submitted Capacity Performance offers. Unit-specific ACR-based offer caps were calculated for eight generation resources (0.7 percent) including five generation resources (0.4 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 1,132 generation resources offered as Capacity Performance, 953 generation resources had the net CONE times B offer cap, zero generation resources had opportunity cost-based offer caps, 11 Planned Generation Capacity Resources had uncapped offers, 31 generation resources had uncapped planned uprates plus net CONE times B offer cap for the existing portion of the units, while the remaining 129 generation resources were price takers.

The APIR statistics are not included in this report, because the number of participants does not meet the minimum requirement defined in PJM's confidentiality rules. The fact that so few resources requested unit specific offer caps is further evidence that the net CONE times B offer cap exceeds competitive offers.

Market power mitigation measures are applied to MOPR Screened Generation Resources such that the sell offer is set equal to the MOPR Floor Offer Price when the submitted sell offer is less than the MOPR Floor Offer Price and an exception was not granted, or the sell offer is set equal to the agreed upon minimum level of sell offer when the sell offer is less than the agreed upon minimum level of sell offer based on a Unit-Specific Exception. As shown in Table 7, of the 7,276.0 ICAP MW of MOPR Unit-

[69] 151 FERC ¶ 61,208.

Specific Exception requests, requests for 4,344.0 ICAP MW were granted. Of the 301.8 MW offered for MOPR Screened Generation Resources, 127.6 MW cleared and 174.2 MW did not clear.

Tables for Offer Caps and Offer Floors

Table 5 Net CONE times B: 2020/2021 and 2021/2022 RPM Base Residual Auctions

	2020/2021					2021/2022					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	$367.97	$87.64	$280.33	0.79	$220.06	$364.78	$54.20	$310.57	0.79	$243.80	($3.19)	($33.44)	$30.24	0.00	$23.74
AEP	$365.52	$103.48	$262.03	0.79	$205.69	$364.43	$66.46	$297.97	0.79	$233.91	($1.09)	($37.02)	$35.94	0.00	$28.22
AP	$365.52	$135.36	$230.15	0.79	$180.67	$364.43	$86.33	$278.10	0.79	$218.31	($1.09)	($49.03)	$47.95	0.00	$37.64
ATSI	$365.52	$121.55	$243.96	0.79	$191.51	$364.43	$75.64	$288.79	0.79	$226.70	($1.09)	($45.92)	$44.83	0.00	$35.19
BGE	$374.61	$208.03	$166.58	0.79	$130.77	$386.17	$156.23	$229.94	0.79	$180.50	$11.56	($51.80)	$63.36	0.00	$49.73
ComEd	$365.52	$57.44	$308.07	0.79	$241.83	$364.43	$40.35	$324.08	0.79	$254.40	($1.09)	($17.10)	$16.01	0.00	$12.57
DAY	$365.52	$110.37	$255.14	0.79	$200.28	$364.43	$70.27	$294.15	0.79	$230.91	($1.09)	($40.10)	$39.01	0.00	$30.63
DEOK	$365.52	$101.67	$263.85	0.79	$207.12	$364.43	$70.05	$294.38	0.79	$231.09	($1.09)	($31.62)	$30.53	0.00	$23.97
DLCO	$365.52	$98.56	$266.96	0.79	$209.56	$364.43	$65.49	$298.94	0.79	$234.67	($1.09)	($33.07)	$31.98	0.00	$25.11
DPL	$367.97	$129.80	$238.17	0.79	$186.96	$364.78	$82.28	$282.50	0.79	$221.76	($3.19)	($47.52)	$44.33	0.00	$34.80
Dominion	$365.52	$88.29	$277.23	0.79	$217.63	$364.43	$66.16	$298.26	0.79	$234.13	($1.09)	($22.12)	$21.03	0.00	$16.50
EKPC	$365.52	$89.03	$276.49	0.79	$217.04	$364.43	$55.61	$308.82	0.79	$242.42	($1.09)	($33.42)	$32.33	0.00	$25.38
External	$368.44	$94.80	$273.64	0.79	$214.81	$370.71	$68.08	$302.63	0.79	$237.56	$2.27	($26.71)	$28.99	0.00	$22.75
JCPL	$367.97	$123.24	$244.73	0.79	$192.11	$364.78	$87.85	$276.92	0.79	$217.38	($3.19)	($35.39)	$32.19	0.00	$25.27
Met-Ed	$365.66	$117.20	$248.45	0.79	$195.03	$367.46	$92.64	$274.82	0.79	$215.73	$1.81	($24.56)	$26.37	0.00	$20.70
PECO	$367.97	$113.53	$254.44	0.79	$199.74	$364.78	$82.65	$282.13	0.79	$221.47	($3.19)	($30.88)	$27.69	0.00	$21.73
PENELEC	$365.66	$235.26	$130.40	0.79	$102.36	$367.46	$165.64	$201.82	0.79	$158.43	$1.81	($69.62)	$71.42	0.00	$56.07
PPL	$365.66	$115.95	$249.71	0.79	$196.02	$367.46	$84.45	$283.01	0.79	$222.16	$1.81	($31.49)	$33.30	0.00	$26.14
PSEG	$367.97	$81.28	$286.69	0.79	$225.05	$364.78	$53.64	$311.13	0.79	$244.24	($3.19)	($27.64)	$24.44	0.00	$19.19
Pepco	$374.61	$163.01	$211.60	0.79	$166.11	$386.17	$117.56	$268.61	0.79	$210.86	$11.56	($45.44)	$57.01	0.00	$44.75
RECO	$367.97	$85.67	$282.30	0.79	$221.61	$364.78	$56.32	$308.45	0.79	$242.13	($3.19)	($29.35)	$26.15	0.00	$20.52

Table 6 ACR statistics: 2021/2022 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)	5	0.4%
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	953	84.2%
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	31	2.7%
Uncapped planned uprates and price taker	0	0.0%
Uncapped planned generation resources	11	1.0%
Existing generation resources as price takers	129	11.4%
Total Generation Capacity Resources offered	1,132	100.0%

Table 7 MOPR statistics: 2021/2022 RPM Base Residual Auction

	Number of Requests	ICAP (MW)			UCAP (MW)	
	(Company-Plant Level)	Requested	Granted	Offered	Offered	Cleared
Unit-Specific Exception for resources	8	6,605.0	3,673.0	0.0	0.0	0.0
Unit-Specific Exception for uprates	15	671.0	671.0	131.3	127.6	127.6
Other MOPR Screened Generation Resources	0	0.0	0.0	177.5	174.2	0.0
Total	23	7,276.0	4,344.0	308.8	301.8	127.6

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 intervals (A) in the delivery year. [70]

The competitive offer of a Capacity Performance resource is also based on a market seller's expectations of system level variables during the delivery year: the number of performance assessment intervals (PAI) in a delivery year (H) where the resource is located; the level of performance required to meet its capacity obligation during those performance assessment intervals, measured as the average Balancing Ratio (B); and the level of the bonus performance payment rate (CPBR) compared to the nonperformance charge rate (PPR). This is because in the Capacity Performance pay for performance capacity model, the total capacity revenues earned by a resource are the sum of revenues earned in the forward capacity auctions and additional bonus revenues earned (or charges forfeited) during the delivery year when the resources are required to perform. The level of the bonus performance payment rate depends on the level of underperforming MW net of the underperforming MW excused by PJM during performance assessment intervals for reasons defined in the PJM OATT.[71]

Attachment B explains the derivation of the competitive offer of a Capacity Performance resource. The competitive offer of a resource is the larger of the opportunity cost of taking on a CP obligation (the default offer cap), or a unit specific offer cap that is based on its net ACR. The default offer cap is based on the opportunity cost of taking on a CP obligation when the resource could have earned enough revenues by staying as an energy only resource and earned enough bonus revenues to cover its avoidable costs. If the resource's avoidable costs are higher than what it expects to earn as bonuses during performance assessment intervals in the delivery year, its competitive offer is its net ACR adjusted with any bonuses or nonperformance charges it may incur during the delivery year. The default offer cap defined in the PJM tariff, net CONE times the average Balancing Ratio, is based on a number of assumptions:

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70 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.

71 OATT Attachment DD § 10A (d).

1. The net ACR of a resource is less than its expected energy only bonuses[72]:

$$\mathrm{ACR} \leq \frac{1}{12} \times \sum_{\mathrm{i}=1}^{\mathrm{H}} (\mathrm{CPBR_i} \times \mathrm{A_i})$$

$$\text{or ACR} \leq \frac{(\mathrm{CPBR} \times \mathrm{H} \times \bar{\mathrm{A}})}{12}$$

2. The expected number of performance assessment intervals equals360. (H = 30 hours times 12 intervals per hour)
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 intervals ($\bar{A}$)

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. The recent history of a very low number of emergency actions in PJM reflect the improvements to generator performance with the capacity performance design and the reduction in pool wide outage rates because of new units in the system and retirements of old units, the upward biased peak load forecasts used in RPM, and the high reserve margins in capacity.[73] [74] Given these developments, the assumption that there would be 30 hours of emergency actions in a year that would trigger performance assessment intervals is unsupported.

The competitive offer calculation of a market seller whose assumptions are different from the assumptions used in the current default offer cap is illustrated in an example.

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72 H is the expected number of performance intervals in a delivery year and CPBR is the bonus payment rate in $ per MWh. The conversion factor of 12 is the number of five minute intervals in each hour.

73 PJM experienced zero emergency events since April 2014, that would have triggered a PAI in an area that at least encompasses a PJM transmission zone. See "Balancing Ratio Determination Issue", at 12 <http://www.pjm.com/-/media/committees-groups/committees/mic/20180404/20180404-item-10b1-balancing-ratio-determination-solution-options.ashx> (April 4, 2018).

74 See *2018 Quarterly State of the Market Report for PJM: January through June*, Vol. 2, Section 5, Capacity, Table 5-7.

The example uses the net CONE and average balancing ratio value used for the default offer cap published by PJM for the 2021/2022 BRA.[75]

Example Competitive Offer Calculation

Consider two resources in the AEP Zone with different avoidable costs, but otherwise similar assumptions:

- Resource X with a net ACR of $50,000 per ICAP MW per year, or $136.99 per ICAP MW per day.
- Resource Y with a net ACR of $10,000 per ICAP MW per year, or $27.40 per ICAP MW per day.
- Expected average performance ($\bar{A}$) of 75 percent during performance assessment intervals.
- Expected number of performance assessment intervals, H, is 60 (5 hours).
- Expected average balancing ratio ($\bar{B}$) during performance assessment intervals is 78.5 percent.
- Expectation 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).

Resource X

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

Energy only bonus revenues = $(\text{CPBR} \times \text{H} \times \bar{\text{A}})/12$

Using a bonus performance rate of 0.8 times the nonperformance charge rate for the AEP zone, CPBR ($ per MWh) = $3,625.30 × 0.8 = $2,900.24 per MWh

Energy only bonus revenues = 2,900.24 ($/MWh) × 60 (intervals/year) × 0.75 /12 (intervals per hour)

= $10,875.90 per MW–year

[75] *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>.

The net ACR of the resource ($50,000 per MW-year) is greater than its expected energy only bonus revenues ($10,875.90 per MW-year). This is primarily because the lower number of performance assessment intervals creates fewer opportunities to earn bonuses. We refer to such resources as a 'High ACR' resource. The competitive offer of such a resource is:

$$p = \mathrm{ACR} + \mathrm{PPR} \times \mathrm{H} \times (\overline{\mathrm{B}} - \overline{\mathrm{A}})/12$$

In other words, the competitive offer is the sum of the resource's avoidable costs (ACR) plus any additional nonperformance charges it may incur due to nonperformance in the energy market during PAIs in the delivery year ($\mathrm{PPR} \times \mathrm{H} \times (\overline{\mathrm{B}} - \overline{\mathrm{A}})/12$). 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:

$$p = \$50{,}000 + \$\,3{,}625.30 \times 60 \times (0.785 - 0.75)/12$$

p = $50,634.43 per MW-year or $138.72 per MW-day

Resource Y

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

Energy only bonus revenues = $(\mathrm{CPBR} \times \mathrm{H} \times \overline{\mathrm{A}})/12$

Using a bonus performance rate of 0.8 times the nonperformance charge rate for the AEP zone, CPBR ($ per MWh) = $3,625.30 × 0.8 = $2,900.24 per MWh

Energy only bonus revenues = 2,900.24 ($/MWh) × 60 (intervals/year) × 0.75 /12 (intervals per hour)

= $10,875.90 per MW–year

The net ACR of the resource ($10,000 per MW-year) is lower than its expected energy only bonus revenues ($10,875.90 per MW-year). We refer to such resources as a 'Low ACR' resource. For such a resource to take on a capacity performance obligation, the minimum offer is the opportunity cost of doing so instead of staying on as an energy only resource. The competitive offer of such a resource is:

$$p = (\mathrm{CPBR} \times \mathrm{H} \times \overline{\mathrm{A}})/12 + (\mathrm{PPR} \times \mathrm{H} \times (\overline{\mathrm{B}} - \overline{\mathrm{A}}))/12$$

In other words, the competitive offer is the sum of the bonus revenues it would have earned as an energy only resource ($(\mathrm{CPBR} \times \mathrm{H} \times \overline{\mathrm{A}})/12$) plus any additional nonperformance charges it expects to pay as a CP resource ($(\mathrm{PPR} \times \mathrm{H} \times (\overline{\mathrm{B}} - \overline{\mathrm{A}}))/12$).

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:

$$p = (\$2{,}900.24 \times 60 \times 0.75)/12 + (\$3{,}625.30 \times 60 \times (0.785 - 0.75))/12$$

p = $11,510.33 per MW-year or $31.54 per MW-day

In comparison, the current default offer cap for the AEP zone, net CONE times B is:

Default offer cap = $85,375 per MW-year or $233.91 per MW-day

This example illustrates how, when a market seller's expectation on two variables 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, and the expected number of performance assessment intervals is 60), the competitive offers of resources across a range of avoidable costs are lower than the current default offer cap. This means that the default offer cap overstates the competitive offer for most resources. These resources are 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: resource availability (A) and balancing ratio (B). These expectations can lead to competitive offers below net CONE times B, the default offer cap. The observed 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 intervals (H) will be less than 360; (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.

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 interval. Such a transaction allows the underperforming resource to avoid paying nonperformance charges by adjusting its expected performance after a performance assessment interval. 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 1,132 generation resources in the 2021/2022 RPM Base Residual Auction, compared to 1,114 generation resources offered in the 2020/2021 RPM Base Residual Auction, a net increase of 18 generation resources. This was a result of 40 additional generation resources offered offset by 22 fewer generation resources offered.

The 40 additional generation resources offered consisted of 17 new resources (325.5 MW), 16 resources that were unoffered in the 2020/2021 BRA (370.8 MW), and seven resources that were previously entirely FRR committed (72.2 MW).[76]

The 17 new Generation Capacity Resources consisted of 12 solar resources (237.8 MW), three wind resources (65.7 MW), and three additional resources (22.0 MW). [77]

The 22 fewer generation resources offered consisted of nine deactivated resources (436.5 MW), five external resources not offered (610.3 MW), three intermittent resources not offered (5.3 MW), two Planned Generation Capacity Resources not offered (160.4 MW), two fewer resources resulting from aggregation of RPM resources, and one additional resource fully committed to FRR (23.2 MW). Table 8 shows Generation Capacity Resources for which deactivation requests have been submitted which affected supply between the 2020/2021 BRA and the 2021/2022 BRA.

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

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

Table 8 Generation Capacity Resource deactivations

Resource Name	LDA	ICAP (MW)	Date Deactivation Notice Submitted	Projected or Actual Deactivation Date
HARRISBURG 4	PPL	14.0	19-Aug-16	17-Nov-16
ROANOKE VALLEY 1	RTO	165.0	01-Dec-16	01-Mar-17
ROANOKE VALLEY 2	RTO	44.0	01-Dec-16	01-Mar-17
SPRUANCE 1 RICH 1-2	RTO	115.5	18-Apr-17	12-Jan-19
COLVER NUG	MAAC	110.0	22-Nov-17	01-Sep-20
BRUNNER ISLAND DIESELS	PPL	7.5	27-Nov-17	25-Feb-18
DIXON LEE LF	ComEd	3.6	06-Dec-17	10-Jan-18
EVERGREEN	MAAC	25.0	02-Feb-18	01-May-18
MORRIS COGEN	ComEd	1.9	16-Feb-18	31-May-18

RTO Market Results

Total Offers

Table 9 shows total RTO offer data for the 2021/2022 RPM Base Residual Auction. All MW values stated in the RTO section include all nested LDAs.[78] [79] As shown in Table 14, total internal RTO unforced capacity (UCAP), excluding generation winter capacity, increased 3,962.0 MW (2.0 percent) from 200,728.4 MW in the 2020/2021 RPM BRA to 204,690.4 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. As shown in Table 14, the 3,962.0 MW increase in internal capacity was a result of net generation capacity modifications (cap mods) (2,467.0 MW), net DR capacity changes (1,055.9 MW), net EE modifications (594.4 MW), the EFORd effect due to higher sell offer EFORds (-164.6 MW), and the DR and EE effect due to a higher Load Management UCAP conversion factor (9.3 MW).[80]

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78 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.

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

80 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

As shown in Table 16, total internal RTO unforced winter capacity for November through April increased 253.1 MW from 825.2 MW in the 2020/2021 BRA to 1,078.3 MW in the 2021/2022 BRA. The 253.1 MW increase in winter capacity was a result of net generation winter capacity modifications (253.1 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 2021/2022 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.[81] 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.[82] Otherwise the owner must take an outage, as appropriate, if the owner cannot provide energy consistent with the ICAP of the unit. Capacity modifications, DR plan changes, and EE plan changes were the result of owner reevaluation of the capabilities of their generation, DR and EE, at least partially in response to the incentives and penalties contained in RPM as modified by CP changes.

After accounting for generation winter capacity, for FRR committed resources and for imports, total RPM capacity was 196,434.6 MW compared to 192,723.4 MW in the

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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 2020/2021 BRA, this conversion factor was 1.0892. For the 2021/2022 BRA, this conversion factor was 1.0898. 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.

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

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

2020/2021 RPM Base Residual Auction.[83] Generation winter capacity increased by 125.5 MW, FRR volumes decreased by 102.8 MW, and imports decreased by 479.1 MW.[84] Of the 4,911.6 MW of imports, 441.2 MW were committed to an FRR capacity plan and 4,470.4 MW were offered in the auction, of which 4,051.8 MW cleared. Of the cleared imports, 1,909.9 MW (51.6 percent) were from MISO. RPM capacity was reduced by exports of 1,295.0 MW, an increase of 1.7 MW from the 2020/2021 RPM Base Residual Auction. Of total exports, 670.3 MW (51.8 percent) were to NYISO, 547.6 MW (42.3 percent) were to MISO, and 77.1 MW (6.0 percent) were to Duke Energy Carolinas.

In addition, RPM capacity was reduced by (3,005.3) MW of Planned Generation Capacity Resources which were not subject to the RPM must offer requirement, by (1,397.6) MW of intermittent resources and (574.9) MW of capacity storage resources which were not subject to the CP must offer requirement, and by (3,017.5) MW which were excused from the RPM must offer requirement. The excused Existing Generation Capacity Resources were the result of plans for retirement (2,568.7 MW), the resource being reasonably expected to be physically incapable of satisfying the requirements of a Capacity Performance Resource (233.3 MW), the resource being considered existing for purposes of the RPM must offer requirement and mitigation only because it cleared an RPM Auction in a prior delivery year but is unable to achieve full commercial operation prior to the delivery year (141.5 MW), and significant physical operational restrictions (74.0 MW).[85] Subtracting 16.1 MW of FRR optional volumes not offered, an increase of 16.1 MW from the 2020/2021 RPM Base Residual Auction, 894.1 MW of DR and EE not offered, and 249.3 MW of unoffered generation winter capacity resulted in 185,984.8 MW that were available to be offered in the RPM Auction, an increase of 3,903.5 MW from the 2020/2021 RPM Base Residual Auction.[86] [87] After accounting for these factors, 437.8 MW were not offered and unexcused in the RPM Auction.

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83 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.

84 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.

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

86 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

Offered MW increased 3,465.8 MW from 182,081.2 MW to 185,547.0 MW, while the overall RTO Reliability Requirement adjusted for FRR obligations, from which the demand curve is developed, decreased 1,194.5 MW from 154,355.3 MW to 153,160.8 MW from the 2020/2021 RPM Base Residual Auction. 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.[88] The 1,194.5 MW decrease in the RTO Reliability Requirement adjusted for FRR obligations from the 2020/2021 RPM Base Residual Auction was a result of a 1,289.1 MW decrease in the RTO Reliability Requirement not adjusted for FRR offset by a 94.6 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 1,267.6 MW from the 2020/2021 RPM Base Residual Auction to 152,647.4 MW. The 1,289.1 MW decrease in the RTO Reliability Requirement was a result of a (1,380.7) MW decrease in the forecast peak load in UCAP terms holding the FPR constant at the 2020/2021 level offset by a 91.6 MW increase attributable to the change in the FPR. The increase in the FPR from the 2020/2021 RPM Base Residual Auction is a result of a decrease in the Pool Wide Average EFORd offset by a decrease in the IRM.

Table 17 shows the installed and offered generation capacity for the top five owners. The total installed capacity (203,896.0 MW) includes all Generation Capacity Resources that qualified as PJM Capacity Resources for the 2021/2022 RPM Base Residual Auction (198,147.3 ICAP MW), annual equivalent MW quantity for generation winter capacity (534.7 ICAP MW), and external resources offered or committed to an FRR plan (5,214.0 ICAP MW).

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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.

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

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

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.[89] As shown in Table 12, the preliminary Net Load Price is $140.53 per MW-day in the RTO.

As shown in Table 10 and Table 11, the 160,795.3 MW of cleared and make whole generation and DR for the entire RTO, resulted in a reserve margin of 22.0 percent and a net excess of 8,190.3 MW over the reliability requirement adjusted for FRR and PRD of 152,605.0 MW (Installed Reserve Margin (IRM) of 15.8 percent).[90] [91] [92] [93] Net excess decreased 1,461.2 MW from the net excess of 9,651.5 MW in the 2020/2021 RPM Base Residual Auction.[94] 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 21.1 percent and a net excess of 7,431.8 MW over the reliability requirement adjusted for FRR and PRD of 152,605.0 MW. As shown in Figure 1, the downward sloping VRR demand curve resulted in a clearing price for Capacity Performance Resources of $140.00 per MW-day.

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

90 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.

91 The IRM decreased from 16.6 percent in the 2020/2021 RPM Base Residual Auction to 15.8 percent in the 2021/2022 RPM Base Residual Auction.

92 The 22.0 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.

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

94 The net excess calculation for the 2020/2021 RPM Base Residual Auction reported in the *Analysis of 2020/2021 RPM Base Residual Auction* has been revised.

Capacity market sellers are allowed to offer up to 10 sell offer segments for a resource and, for annual resources, specify a minimum MW quantity for every segment. The capacity market rules do not require the segments to be aligned with the physical operating attributes of the underlying capacity resource. In a competitive capacity market, there is no valid economic reason for capacity market sellers to specify a minimum MW quantity greater than 0 MW (inflexible sell offer segment) when offering a resource in multiple segments. A valid economic argument could be made for specifying a minimum MW quantity greater than 0 MW if the resource were offered as a single segment, representing one unit. The MMU recommends that capacity market sellers be required to request the use of minimum MW quantities greater than 0 MW (inflexible sell offer segments) and that the requests should only be permitted for defined physical reasons.

If the market clears on a nonflexible sell offer segment, a sell offer that specifies a minimum block MW value greater than zero, the Capacity Market Seller will be assigned 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.[95] 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.[96] [97] The market results in the 2021/2022 BRA 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.[98] [99] 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

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95 OATT Attachment DD § 5.14 (b).

96 OATT Attachment DD § 5.12 (a).

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

98 OATT Attachment DD § 5.14 (c) (2).

99 OATT Attachment DD § 6.8 (a).

awarded a make whole payment.[100] The market results in the 2021/2022 BRA did not include make whole MW or payments related to NEPA or Multi-Year Pricing Option.

The market results in the 2021/2022 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 18 shows offered and cleared MW by LDA, resource type, and season in the 2021/2022 RPM Base Residual Auction. Of the 171,249.8 MW of generation offers, 170,841.5 MW were for the annual season. Of the 11,494.0 MW of DR offers, 11,094.6 MW were for the annual season. Of the 2,803.2 MW of EE offers, 2,649.0 MW were for the annual season.

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

Table 20 shows the offered MW by resource type, offer/product type, and price range as percent of net CONE times B in the 2021/2022 RPM Base Residual Auction. Capacity Performance generation offers between 50 percent of net CONE times B and greater than 100 percent times net CONE times B increased by 7,888.2 MW from the 2020/2021 RPM Base Residual Auction.

Table 21 shows cleared MW by zone and fuel source. Of the 171,249.8 MW offered for generation resources, 149,997.6 MW cleared (87.6 percent). Of the 163,627.3 cleared MW in the entire RTO, 26,343.7 MW (16.1 percent) cleared in Dominion, followed by 22,358.1

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

MW (13.7 percent) in ComEd and 16,810.7 MW (10.3 percent) in AEP. Of the 149,997.6 cleared MW for generation resources in the entire RTO, 75,946.7 MW (50.6 percent) were gas resources, followed by 41,193.6 MW (27.5 percent) from coal resources and 19,917.9 MW (13.3 percent) from nuclear resources. Cleared MW from nuclear resources decreased 7,473.1 from the 2020/2021 RPM Base Residual Auction while cleared MW from DR and EE resources increased 4,293.4 MW from the 2020/2021 RPM Base Residual Auction.

The 21,919.7 MW uncleared MW in the entire RTO were the result of offer prices which exceeded the clearing prices. Of the 21,919.7 uncleared MW in the entire RTO, 74.9 MW were EE offers, 592.4 MW were DR offers, and the remaining 21,252.3 MW were generation offers.[101] Table 22 presents details on the generation offers that did not clear. Of the 21,252.3 MW of uncleared generation offers, 10,656.0 MW (50.1 percent) were for generation resources greater than 40 years old, and 10,596.3 MW (49.9 percent) were for generation resources less than or equal to 40 years old.

Table 23 shows the auction results for the prior two Delivery Years for the generation resources that did not clear some or all MW in the 2021/2022 BRA. Of the 269 generation resources that did not clear 21,252.3 MW in the 2021/2022 BRA, 137 of those generation resources did not clear 7,894.2 MW in RPM Auctions for the 2020/2021 Delivery Year. Of those 137 generation resources that did not clear MW in RPM Auctions for the 2021/2022 and 2020/2021 Delivery Years, 79 of those generation resources did not clear 4,711.5 MW in RPM Auctions for the 2019/2020 Delivery Year. Thus, 7,894.2 MW of capacity did not clear in two sequential auctions, but 4,711.5 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

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

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 2021/2022 RPM Base Residual Auction, EMAAC had 4,352.6 MW of CTRs with a total value of $40,877,295, PSEG had 4,990.5 MW of CTRs with a total value of $70,238,159, ATSI had 6,402.8 MW of CTRs with a total value of $73,219,252, ComEd had 1,527.9 MW of CTRs with a total value of $30,978,820, and BGE had 5,125.6 MW of CTRs with a total value of $112,812,971.

EMAAC had 40.0 MW of customer funded ICTRs with a total value of $375,658, PSEG had 41.0 MW of customer funded ICTRs with a total value of $577,050, BGE had 65.7 MW of customer funded ICTRs with a total value of $6,734,907, and COMED had 1,097.0 MW of customer funded ICTRs with a total value of $22,242,498.

EMAAC had 948.0 MW of ICTRs due to Incremental Rights-Eligible Required Transmission Enhancements with a value of $8,903,095. PSEG had 499.4 MW of ICTRs due to Incremental Rights-Eligible Required Transmission Enhancements with a value of $7,605,806. BGE had 306.0 MW of ICTRs due to Incremental Rights-Eligible Required Transmission Enhancements with a value of $8,180,931.

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

[102] "PJM Manual 14B: PJM Region Transmission Planning Process, Attachment C: PJM Deliverability Testing Methods," Rev. 41 (April 19, 2018) at 66. Manual 14B indicates that all "electrically cohesive load areas" are tested.

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.[103]

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.[104] 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."[105] 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.

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

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103 "PJM Manual 18: PJM Capacity Market," Rev. 40 (Feb. 22, 2018) at 24.

104 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.

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

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 24 shows the CETL and CETO values used in the 2021/2022 study compared to the 2020/2021 values. The CETL values for the ComEd and PSEG North LDAs changed significantly. The ComEd CETL increased due to "two baseline 345 kV transmission reconductoring projects in AEP (b2776 and b2777) as well as two baseline 345 kV transmission upgrades in COMED (b2930 and b2931) that were not included in the 2020/2021 BRA CETL power flow study."[106] The PSEG and PSEG North CETL decreased due to load deliverability rules approved by the PJM Markets & Reliability Committee (MRC), offset by the conversion of the HTP merchant transmission project's firm transmission withdrawal rights to nonfirm transmission withdrawal rights. Under the new rules, the transactions that are not secured with firm transmission rights are excluded from CETL studies. The PSEG CETL also decreased due to the suspension of the ISA for the Poseidon merchant transmission project.

PJM appears to recognize that it is not appropriate to include assumptions of any emergency imports, which are equivalent to assuming capacity imports from NYISO in the CETL studies. Prior to the 2021/2022 BRA, PJM included capacity imports and exports secured with both firm and nonfirm transmission in the CETL studies. Starting with the 2021/2022 BRA, PJM included only capacity imports and exports secured with firm transmission in the CETL studies. For the 2021/2022 BRA, all imports and exports secured with firm transmission that were approved and confirmed by PJM regardless of their approval status from the neighboring regions were included in CETL studies despite the fact that they were not and could not be capacity imports. PJM has made rule changes such that starting with the 2022/2023 BRA only those imports and exports secured with firm transmission that were approved and confirmed by all relevant

[106] See PJM "2021/2022 RPM Base Residual Auction Planning Period Parameters" <http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-rpm-bra-planning-parameters-report.ashx?la=en> (February 1, 2018).

entities will be included in the CETL cases.[107] The MMU recommends that PJM not include any capacity imports, even those secured with firm transmission service, from neighboring regions in the CETL analyses. The imports are not capacity imports. Treating imports as a source of capacity, directly analogous to an import of capacity from within PJM, overstates the supply of capacity and suppresses the capacity price compared to the competitive level. In addition, the imports, despite firm reservation, are not guaranteed to perform under all conditions to meet PJM's capacity market obligations. If Transmission Loading Relief 5a or 5b is initiated, the transactions secured by firm transmission service could also be curtailed.[108] The imports from neighboring regions are not substitutes for PJM's internal capacity resources and should not be treated as substitutes.

Table 25 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 PSEG 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.[109] The information that resulted in a reduction in the CETL values was available prior to the 2020/2021 BRA and the proposed CETL values should have been calculated prior to the 2020/2021 BRA and implemented in the 2020/2021 BRA.

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.

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

108 Additional details regarding the TLR procedure can be found in NERC. "*Standard IRO-006-4 – Reliability Coordination – Transmission Loading Relief*" (October 23, 2007).

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

There were five locationally binding constraints in the 2021/2022 BRA which resulted in demand clearing in a locationally constrained LDA which did not clear in the RTO market or in contiguous or parent LDAs and which cleared at a higher price than in contiguous or parent LDAs. The result was to shift the demand curve in the RTO market to the left along the upwardly sloping supply curve and to reduce the price in the RTO market. The price impact is the result both of the size of the shift of the demand curve and the slope of the supply curve. The larger the shift in the demand curve and the steeper the slope of the supply curve, the greater the price impact.

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.

Impact of ComEd CETL (Scenario 1)

The ComEd CETL for the 2021/2022 RPM Base Residual Auction was 1,510.0 MW higher than the 2020/2021 ComEd CETL level, an increase of 37.2 percent. Table 26 shows the results if the 2020/2021 CETL value for ComEd had been used in the 2021/2022 RPM Base Residual Auction and everything else had remained the same. The results of the scenario show that the ComEd price for the 2021/2022 RPM Base Residual Auction was higher than it would have been if the CETL had remained at the lower 2020/2021 CETL value. This counter intuitive price impact was a result of the interaction of the supply offers and the demand curve.

All binding constraints would have remained the same except that the DEOK LDA is also binding. The RTO clearing price would have decreased to $112.75 per MW-day, and the clearing quantity would have increased to 164,508.9 MW. The clearing quantity of seasonal capacity would have remained the same at 715.5 MW. The ATSI clearing price would have remained the same at $171.33 per MW-day, and the clearing quantity would have remained the same at 8,007.3 MW. The clearing quantity of seasonal capacity for satisfying ATSI's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have remained the same at $165.73 per MW-day, and the clearing quantity would have remained the same at 29,288.5 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement remained the same at 1.0 MW. The PSEG clearing price would remained the same at $204.29 per MW-day, and the clearing quantity would have remained the same at 5,367.6 MW. The clearing quantity of seasonal capacity for satisfying PSEG's reliability requirement remained the same at 1.0 MW. The BGE clearing price would have decreased to $180.50 per MW-day, and the clearing quantity would have increased to 1,959.6 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement remained the same at 0 MW. The ComEd clearing price would have decreased to $189.10 per MW-day, and the clearing quantity would have increased to 23,901.3 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement remained the same at 274.5 MW. The DEOK clearing price would have decreased to $128.47 per MW-day and the clearing quantity would have decreased to 2,636.3 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 2021/2022 RPM Base Residual Auction were $9,300,877,106. If the 2020/2021 CETL value for ComEd had been used in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $8,320,327,063, a decrease of $980,550,043, or 10.5 percent, compared to the actual results. From another perspective, the use of the 2021/2022 CETL value for ComEd resulted in a 11.8 percent increase in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been using the 2020/2021 CETL value for ComEd.

Impact of PSEG CETL Adjustment (Scenario 2)

PJM introduced updates to the PJM Region Transmission Planning Process and corrections to the CETL calculations in August 2017. The planning process updates stem from the termination of the ConEd Wheel Agreement. The updates included changes to the PJM NYISO PAR flows and PJM will no longer assume nonfirm import capacity from outside PJM is available when determining the CETL values for MAAC, EMAAC, PSEG, and PSEG North.[110] Table 25 shows the CETL values for MAAC, EMAAC, PSEG, and PSEG North for the 2020/2021 BRA and the 2021/2022 BRA, and the proposed CETL values from August 2017.

The 2021/2022 CETL value for MAAC is 4,019 which is 199 MW less than the 2020/2021 MAAC CETL value and 901 MW greater than the August 2017 value. The 2021/2022 CETL value for EMAAC is 9,000 which is 200 MW greater than the 2020/2021 EMAAC CETL value and 700 MW greater than the August 2017 value. The 2021/2022 CETL value for PSEG is 6,902 which is 1,099 MW less than the 2020/2021 MAAC CETL value and 428 MW greater than the August 2017 value. The 2021/2022 CETL value for PSEG North is 3,180 which is 1,084 MW less than the 2020/2021 MAAC CETL value and 225 MW greater than the August 2017 value.

PJM included power flows associated with capacity imports and exports secured with firm transmission from neighboring regions in calculating CETL values between LDAs.

110 See "M14B Updates," presented at August 10, 2017, meeting of Planning Committee.

To approximate the impact of power flows associated with imports from New York ISO, a sensitivity with a 200.0 MW reduction in the CETL value for PSEG LDA was used.

Table 27 shows the results if the PSEG CETL value was reduced by 200.0 MW in the 2021/2022 RPM Base Residual Auction and everything else had remained the same. All binding constraints would have remained the same. The RTO clearing price would have remained the same at $140.00 per MW-day and the clearing quantity would have remained the same at 163,627.3 MW. The clearing quantity of seasonal capacity would have remained the same at 715.5 MW. The ATSI clearing price would have remained the same at $171.33 per MW-day, and the clearing quantity would have remained the same at 8,007.3 MW. The clearing quantity of seasonal capacity for satisfying ATSI's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have decreased to $165.47 per MW-day, and the clearing quantity would have increased to 29,290.5 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 1.0 MW. The PSEG clearing price would have increased to $206.58 per MW-day, and the clearing quantity would have increased to 5,562.2 MW. The clearing quantity of seasonal capacity for satisfying PSEG's reliability requirement would have remained the same at 1.0 MW. The BGE clearing price would have remained the same at $200.30 per MW-day, and the clearing quantity would have remained the same at 1,937.7 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have remained the same at $195.55 per MW-day, and the clearing quantity would have remained the same at 22,358.1 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have remained the same at 274.5 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If the PSEG CETL value was reduced by 200.0 MW in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $9,306,030,179, an increase of $5,153,073, or 0.1 percent, compared to the actual results. From another perspective, the use of the 2021/2022 CETL value for PSEG LDA resulted in a 0.1 percent decrease in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been had the CETL value for PSEG LDA been reduced by 200.0 MW in the 2021/2022 RPM Base Residual Auction.

Impact of the Forecast Peak Load (Scenario 3)

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. The Third IA is the last auction prior to the beginning of the delivery year, and the peak load forecast for the Third IA provides the best indicator of the capacity needed to meet the reliability criterion. For the five delivery years from 2014/2015 through 2018/2019, the peak load forecast for the Third IA has been on average 5.8 percent lower than the peak load forecast used in the corresponding BRA.

Table 28 shows the results if the peak load forecast had been reduced by 5.8 percent in the 2021/2022 RPM Base Residual Auction and everything else had remained the same. All binding constraints would have remained the same except that the DEOK LDA is also binding. The RTO clearing price would have decreased to $80.00 per MW-day, and the clearing quantity would have decreased to 155,349.8 MW. The amount of cleared seasonal capacity would have decreased to 623.5 MW. The ATSI clearing price would have increased to $226.40 per MW-day, and the clearing quantity would have decreased to 6,889.1 MW. The clearing quantity of seasonal capacity for satisfying ATSI's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have decreased to $139.46 per MW-day, and the clearing quantity would have decreased to 27,310.0 MW. The clearing quantity for seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 1.0 MW. The PSEG clearing price would have decreased to $160.00 per MW-day, and the clearing quantity would have decreased to 4,776.5 MW. The clearing quantity for seasonal capacity for satisfying PSEG's reliability requirement would have remained the same at 1.0 MW. The BGE clearing price would have decreased to $178.77 per MW-day, and the clearing quantity would have decreased to 1,492.6 MW. The clearing quantity for seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have increased to $198.48 per MW-day, and the clearing quantity would have decreased to 20,772.7 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have remained the same at 274.5 MW. The DEOK clearing price would have decreased to $107.23 per MW-day and the clearing quantity would have decreased to 2,284.4 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 2021/2022 RPM Base Residual Auction were $9,300,877,106. If the peak load forecast for the 2021/2022 RPM Base Residual Auction had been 5.8 percent lower and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $6,510,513,224, a decrease of $2,790,363,882, or 30.0 percent, compared to the actual results. From another perspective, using PJM's peak load forecast for the 2021/2022 Base Residual Auction resulted in a 42.9 percent increase in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what revenues would have been using a load forecast that is 5.8 percent below the PJM peak load forecast. (Scenario 3)

Impact of Rightward Shift of the VRR Curve (Scenario 4)

Beginning with the 2018/2019 RPM Base Residual Auction, PJM has included a one percent rightward shift in the VRR curve to mitigate certain low probability risks. The shift was recommended by the Brattle Group to lower the probability of under procuring capacity in the event of a supply or demand shock, or underestimating net CONE.[111] PJM provided additional details regarding the shift to the Commission, basing the need for the VRR curve shift on uncertainty of supply due to the Mercury and Air Toxic Standards (MATS), the vacating of Order 745, the EPA's Greenhouse Gas Rule, and advances in combined cycle generation.[112] The Commission approved the change noting "PJM appropriately accounted for this modeling inadequacy and the underlying potential for supply shifts with a more conservative VRR Curve, i.e., with a VRR Curve that will result in the procurement of additional capacity."[113]

Table 29 shows the results of the 2021/2022 RPM Base Residual Auction had the VRR curve not included a one percent rightward shift and everything else had remained the same. All binding constraints would have remained the same. The RTO clearing price would have decreased to $129.43 per MW-day, and the clearing quantity would have decreased to 162,646.5 MW. The amount of cleared seasonal capacity would have remained the same at 715.5 MW. The ATSI clearing price would have decreased to $145.00 per MW-day, and the clearing quantity would have decreased to 7,963.5 MW. The clearing quantity of seasonal capacity for satisfying ATSI's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have decreased to $165.00 per MW-day, and the clearing quantity would have decreased to 28,983.4 MW. The clearing quantity for seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 1.0 MW. The PSEG clearing price would have decreased to $194.47 per MW-day, and the clearing quantity would have decreased to 5,291.5 MW. The clearing quantity for seasonal capacity for satisfying PSEG's reliability requirement would have remained the same at 1.0 MW. The BGE clearing price would have decreased to $178.77 per MW-day, and the clearing quantity would have decreased to 1,895.2 MW. The clearing quantity for seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have decreased to $184.04 per MW-day, and the clearing

111 See PJM "Third Triennial Review of PJM's Variable Resource Requirement Curve" <http://www.pjm.com/-/media/library/reports-notices/reliability-pricing-model/20140515-brattle-2014-pjm-vrr-curve-report.ashx?la=en> (May 15, 2014) at 68.

112 149 FERC ¶ 61,183 at P 25 (2014).

113 Ibid at P. 52.

quantity would have decreased to 22,191.9 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have remained the same at 274.5 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If the VRR curve for the 2021/2022 RPM Base Residual Auction had not included a one percent shift to the right and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $8,648,601,896, a decrease of $652,275,210, or 7.0 percent, compared to the actual results. From another perspective, shifting the VRR curve to the right by one percent for the 2021/2022 Base Residual Auction resulted in a 7.5 percent increase in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what revenues would have been had the VRR curve not been shifted. (Scenario 4)

Composition of the Steeply Sloped Portion of the Supply Curve

Table 30 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 6.6 percent of the offers greater than $35.00 per MW-day compared to 6.2 percent in the 2020/2021 RPM Base Residual Auction. Offers for coal fired units made up 30.8 percent of the offers greater than $35.00 per MW-day compared to 35.0 percent in the 2020/2021 RPM Base Residual Auction. Offers for nuclear units made up 19.9 percent of the offers greater than $35.00 per MW-day compared to 10.1 percent in the 2020/2021 RPM Base Residual Auction.

Demand Side Resources in RPM

There are two categories of demand side products included in the RPM market design for the 2021/2022 BRA:[114] [115]

[114] 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.

[115] 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.

- **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.[116] 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.[117]

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:[118] [119]

- **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.

- **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

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

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

118 134 FERC ¶ 61,066 (2011).

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

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:[120] [121]

- **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**
  - **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

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[120] 151 FERC ¶ 61,208.

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

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 31 shows offered and cleared capacity from Demand Resources and Energy Efficiency Resources in the 2021/2022 RPM Base Residual Auction compared to the 2020/2021 RPM Base Residual Auction. Offers for DR increased from 9,113.0 MW in the 2020/2021 BRA to 11,494.0 MW in the 2021/2022 BRA, an increase of 2,380.9 MW or 26.1 percent. Offers for EE increased from 2,042.4 MW in the 2020/2021 BRA to 2,803.2 MW in the 2021/2022 BRA, an increase of 760.7 MW or 37.2 percent.

Impact of All DR and EE (Scenario 5)

Table 32 shows the results if there were no offers for DR or EE in the 2021/2022 RPM Base Residual Auction and everything else had remained the same. The ATSI and the PSEG constraints would have been binding. The RTO clearing price would have increased to $189.11 per MW-day, and the clearing quantity would have decreased to 158,125.4 MW. The clearing quantity of seasonal capacity would have decreased to 106.2 MW. The ATSI clearing price would have increased to $216.83 per MW-day, and the clearing quantity would have decreased to 7,595.6 MW. The clearing quantity of seasonal capacity for satisfying ATSI's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have increased to $189.11 per MW-day, and the clearing quantity would have decreased to 28,481.8 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have decreased to 0 MW. The PSEG clearing price would have increased to $207.08 per MW-day, and the clearing quantity would have decreased to 4,983.6 MW. The clearing quantity of seasonal capacity for satisfying PSEG's reliability requirement would have decreased to 0 MW. The BGE clearing price would have decreased to $189.11 per MW-day, and the clearing quantity would have increased to 2,839.3 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have decreased to $189.11 per MW-day, and the clearing quantity would have decreased to 21,719.1 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have decreased to 0 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If there were no offers for DR or EE in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $11,030,339,776, an increase of $1,729,462,670, or 18.6 percent, compared to the actual results. From another perspective, the inclusion of Demand Resources and Energy Efficiency resources resulted in a 15.7 percent reduction in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been without any Demand Resources or Energy Efficiency resources.

Impact of All EE (Scenario 6)

Table 33 shows the results if there were no offers for EE and the EE add back MW were removed in the 2021/2022 RPM Base Residual Auction and everything else had remained the same. All binding constraints would have remained the same, except that the DEOK constraint would have also been binding. The RTO clearing price would have decreased to $127.28 per MW-day, and the clearing quantity would have decreased to 160,125.8 MW. The clearing quantity of seasonal resources would have remained the same at 715.5 MW. The ATSI clearing price would have decreased to $145.00 per MW-day, and the clearing quantity would have decreased to 7,843.6 MW. The clearing quantity of seasonal capacity for satisfying ATSI's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have decreased to $165.00 per MW-day, and the clearing quantity would have decreased to 28,361.8 MW. The clearing quantity of seasonal resources for satisfying EMAAC's reliability requirement would have remained the same at 1.0 MW. The PSEG clearing price would have decreased to $179.16 per MW-day, and the clearing quantity would have decreased to 5,049.6 MW. The clearing quantity of seasonal resources for satisfying PSEG's reliability requirement would have remained the same at 1.0 MW. The BGE clearing price would have decreased to $191.18 per MW-day, and the clearing quantity would have decreased to 1,834.1 MW. The clearing quantity of seasonal resources for satisfying BGE's reliability requirement would have remained the same at 0 MW. The ComEd clearing price decreased to $189.10 per MW-day, and the clearing quantity would have decreased to 21,548.2 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have decreased to 172.2 MW. The DEOK clearing price would have decreased to $128.47 per MW-day, and the clearing quantity would have decreased to 2,512.9 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 2021/2022 RPM Base Residual Auction were $9,300,877,106. If there were no offers for EE and the EE add back MW were removed in the 2021/2022 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $8,450,275,422, a decrease of $850,601,684, or 9.1 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 10.1 percent increase in RPM revenues for the 2021/2022 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.

Impact of Annual DR and EE (Scenario 7)

Table 34 shows the results if there were no offers for Annual DR or Annual EE in the 2021/2022 RPM Base Residual Auction and everything else had remained the same. The

ATSI and the PSEG constraints would have been binding. The RTO clearing price would have increased to $189.10 per MW-day, and the clearing quantity would have decreased to 158,398.2 MW. The clearing quantity of seasonal capacity would have remained the same at 715.5 MW. The ATSI clearing price would have increased to $216.83 per MW-day, and the clearing quantity would have decreased to 7,614.6 MW. The clearing quantity of seasonal capacity for satisfying ATSI's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have increased to $189.10 per MW-day, and the clearing quantity would have decreased to 28,483.7 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 1.0 MW. The PSEG clearing price would have increased to $207.08 per MW-day, and the clearing quantity would have decreased to 4,985.5 MW. The clearing quantity of seasonal capacity for satisfying PSEG's reliability requirement would have remained the same at 1.0 MW. The BGE clearing price would have decreased to $189.10 per MW-day, and the clearing quantity would have increased to 2,839.3 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have decreased to $189.10 per MW-day, and the clearing quantity would have decreased to 21,637.2 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have remained the same at 274.5 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If there were no offers for Annual DR or Annual EE in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $11,048,633,706, an increase of $1,747,756,600, or 18.8 percent, compared to the actual results. From another perspective, the inclusion of Annual Demand Resources and Annual Energy Efficiency resources resulted in a 15.8 percent reduction in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been without any Annual Demand Resources or Annual Energy Efficiency resources.

Impact of Seasonal DR and Seasonal EE (Scenario 8)

Table 35 shows the results if there were no offers for Seasonal DR or Seasonal EE in the 2021/2022 RPM Base Residual Auction and everything else had remained the same. All binding constraints would have remained the same. The RTO clearing price would have remained the same at $140.00 per MW-day, and the clearing quantity would have decreased to 163,222.5 MW. The clearing quantity of seasonal capacity would have decreased to 106.2 MW. The ATSI clearing price would have decreased to $166.26 per MW-day, and the clearing quantity would have decreased to 8,005.8 MW. The clearing quantity of seasonal capacity for satisfying ATSI's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have decreased to $165.47 per MW-day, and the clearing quantity would have decreased to 29,229.3 MW.

The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have decreased to 0.5 MW. The PSEG clearing price would have decreased to $198.45 per MW-day, and the clearing quantity would have decreased to 5,356.0 MW. The clearing quantity of seasonal capacity for satisfying PSEG's reliability requirement would have decreased to 0.5 MW. The BGE clearing price would have decreased to $198.69 per MW-day, and the clearing quantity would have remained the same at 1,937.7 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have decreased to $190.79 per MW-day, and the clearing quantity would have decreased to 22,255.9 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have decreased to 0 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If there were no offers for Seasonal DR or Seasonal EE in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $9,207,711,533, a decrease of $93,165,573, or 1.0 percent, compared to the actual results. From another perspective, the inclusion of Seasonal Demand Resources and Seasonal Energy Efficiency resources resulted in a 1.0 percent increase in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been without any Seasonal Demand Resources or Seasonal Energy Efficiency resources.

The results show that the inclusion of additional Seasonal DR and Seasonal EE caused price increases in some LDAs and a higher RPM market revenue total. One factor leading to this counter intuitive result is that the EE add back MW for Seasonal Energy Efficiency adjustment to the VRR curve is larger than the amount of Seasonal Energy Efficiency offers, and therefore removing the Seasonal Energy Efficiency resources had a larger impact on demand than supply. The interaction of the supply offers and the demand curve also contributed to the counter intuitive result.

Impact of Seasonal Capacity (Scenario 9)

Table 36 shows the results if there were no offers for Seasonal products (Demand Resources, Energy Efficiency Resources, and Generation Resources) in the 2021/2022 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 $142.49 per MW-day, and the clearing quantity would have decreased to 163,142.0 MW. The clearing quantity of seasonal capacity would have decreased to 0 MW. The ATSI clearing price would have decreased to $166.26 per MW-day, and the clearing quantity would have decreased to 8,005.8 MW. The clearing quantity of seasonal capacity for satisfying ATSI's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have decreased to $165.47 per MW-day, and the clearing quantity would have decreased to 29,229.3 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have decreased to 0 MW. The PSEG clearing price would have decreased to $198.66 per MW-day, and the clearing quantity would have decreased to 5,355.5 MW. The clearing quantity of seasonal capacity for satisfying PSEG's reliability requirement would have decreased to 0 MW. The BGE clearing price would have decreased to $198.69 per MW-day, and the clearing quantity would have remained the same at 1,937.7 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have decreased to $190.79 per MW-day, and the clearing quantity would have decreased to 22,255.9 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have decreased to 0 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If there were no offers for Seasonal products in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $9,296,441,218, a decrease of $4,435,888, or 0.0 percent, compared to the actual results. From another perspective, the inclusion of Seasonal resources resulted in a 0.0 percent increase in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been without any seasonal resources.

The results show that the inclusion of seasonal offers caused price increases in some LDAs and a higher RPM market revenue total. One factor leading to this counter intuitive result is that the EE add back MW for Seasonal Energy Efficiency adjustment to the VRR curve is larger than the amount of Seasonal Energy Efficiency offers, and therefore removing the Seasonal Energy Efficiency resources had a larger impact on demand than supply. The interaction of the supply offers and the demand curve also contributed to the result.

Impact of DR, EE, and Seasonal Capacity (Scenario 10)

Table 37 shows the results if there were no offers for Seasonal products as well as no offers for Annual DR or Annual EE in the 2021/2022 RPM Base Residual Auction and everything else had remained the same. The ATSI and the PSEG constraints would have been binding. The RTO clearing price would have increased to $189.12 per MW-day, and the clearing quantity would have decreased to 158,125.1 MW. The clearing quantity of seasonal capacity would have decreased to 0.0 MW. The ATSI clearing price would have increased to $216.83 per MW-day, and the clearing quantity would have decreased to 7,595.6 MW. The clearing quantity of seasonal capacity for satisfying ATSI's reliability requirement would have remained the same at 0.0 MW. The EMAAC clearing price would have increased to $189.12 per MW-day, and the clearing quantity would have decreased to 28,481.8 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have decreased to 0.0 MW. The PSEG clearing price would have increased to $207.08 per MW-day, and the clearing quantity would have decreased to 4,983.6 MW. The clearing quantity of seasonal capacity for satisfying PSEG's reliability requirement would have decreased to 0.0 MW. The BGE clearing price would have decreased to $189.12 per MW-day, and the clearing quantity would have increased to 2,839.3 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0.0 MW. The ComEd clearing price would have decreased to $189.12 per MW-day, and the clearing quantity would have decreased to 21,825.0 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have decreased to 0.0 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If there were no offers for Seasonal products or demand side products in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $11,031,353,576, an increase of $1,730,476,470, or 18.6 percent, compared to the actual results. From another perspective, the inclusion of Seasonal resources, DR and EE resources resulted in a 15.7 percent decrease in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been without any Seasonal, DR, or EE resources.

The results show that the inclusion of seasonal offers, Annual DR, and Annual EE caused price increases in some LDAs. One factor leading to this counter intuitive result is that the EE add back MW adjustment to the VRR curve is larger than the amount of Energy Efficiency offers, and therefore removing the Energy Efficiency resources had a larger impact on demand than supply. The interaction of the supply offers and the demand curve also contributed to the result.

Impact of Winter Resources (Scenario 11)

Table 38 shows the results if offers from winter resources were reduced by 50 percent in the 2021/2022 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 $141.31 per MW-day, and the clearing quantity would have decreased to 163,584.9 MW. The clearing quantity of seasonal capacity would have decreased to 358.9 MW. The ATSI clearing price would have remained the same at $171.33 per MW-day, and the clearing quantity would have remained the same at 8,007.3 MW. The clearing quantity of seasonal capacity for satisfying ATSI's reliability requirement would have remained the same at 0.0 MW. The EMAAC clearing price would have remained the same at $165.73 per MW-day, and the clearing quantity would have remained the same at 29,288.5 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have decreased to 0.5 MW. The PSEG clearing price would have increased to $204.50 per MW-day, and the clearing quantity would have decreased to 5,367.1 MW. The clearing quantity of seasonal capacity for satisfying

PSEG's reliability requirement would have decreased to 0.5 MW. The BGE clearing price would have remained the same at $200.30 per MW-day, and the clearing quantity would have remained the same at 1,937.7 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0.0 MW. The ComEd clearing price would have decreased to $184.04 per MW-day, and the clearing quantity would have increased to 22,417.4 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have decreased to 137.7 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If offers from Winter resources were reduced by 50 percent in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $9,271,942,523, a decrease of $28,934,583, or 0.3 percent, compared to the actual results. From another perspective, the inclusion of all offers from winter resources resulted in a 0.3 percent increase in RPM revenues for the 2021/2022 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 (Scenario 12)

Table 39 shows the results if Seasonal offers were only matched with complementary Seasonal offers within the same LDA in the 2021/2022 RPM Base Residual Auction and everything else had remained the same. All binding constraints would have remained the same. All LDA clearing prices and clearing amounts would have remained the same and total RPM market revenues would have remained the same at $9,300,877,106.

In the 2021/2022 RPM Base Residual Auction, the proportion of low priced offers for summer in the rest of the RTO, the lowest common parent for all LDAs, substantially increased from the 2020/2021 RPM Base Residual Auction. Restricting the matching of complementary seasonal products to the LDA in which they are located means that a resource that did not clear for a lower LDA such as PSEG could not be matched with a complementary seasonal product in a higher LDA such as rest of the RTO. However, the availability of similarly lower priced offers located in the rest of RTO resulted in no difference in clearing quantities and prices when the seasonal matching was restricted to be within the same LDA where the resources were physically located.

Capacity Imports

Generation external to the PJM region is eligible to be offered into an RPM auction if it meets specific requirements.[122] [123] 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.[124]

Planned External Generation Capacity Resources are eligible to be offered into an RPM Auction if they meet specific requirements.[125] [126] Planned External Generation Capacity Resources are proposed Generation Capacity Resources, or a proposed increase in the capability of an Existing Generation Capacity Resource, that is located outside the PJM region; participates in the generation interconnection process of a balancing authority external to PJM; is scheduled to be physically and electrically interconnected to the transmission facilities of such balancing authority on or before the first day of the delivery year for which the resource is to be committed to satisfy the reliability

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

[123] "PJM Manual 18: PJM Capacity Market," Rev. 40 (Feb. 22, 2018) at 62-65 & 89-90.

[124] OATT, Schedule 1, Section 1.10.1A.

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

[126] "PJM Manual 18: PJM Capacity Market," Rev. 40 (Feb. 22, 2018) at 66-68.

requirements of the PJM Region; and is in full commercial operation prior to the first day of the delivery year.[127] 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.[128]

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.[129] 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.[130]

Effective May 9, 2017, enhanced pseudo tie requirements for external generation capacity resources were implemented, including a transition period with deliverability requirements for existing pseudo tie resources that has previously cleared an RPM auction.[131] The rule changes include defining coordination with other Balancing Authorities when conducting pseudo tie studies, establishing an electrical distance requirement, establishing a market-to-market flowgate test to establish limits on the number of coordinated flowgates PJM must add in order to accommodate a new pseudo-tie, a model consistency requirement, the requirement for the capacity market

[127] 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).

[128] 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).

[129] 147 FERC ¶ 61,060 (2014).

[130] 151 FERC ¶ 61,208 (2015).

[131] 161 FERC ¶ 61,197 (2017).

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

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.

Table 40 shows the MW quantity of imports offered and cleared in the 2007/2008 through 2021/2022 RPM Base Residual Auctions. The highest level of offered (7,493.7 MW) and cleared (7,482.7 MW) imports occurred in the 2016/2017 RPM BRA, which was prior to the implementation of the CIL rules. Of the 4,470.4 MW of imports offered in the 2021/2022 RPM BRA, 4,051.8 MW (90.6 percent) cleared.

Impact of Imports (Scenario 13, Scenario 14, Scenario 15, Scenario 16)

Reduction by 25 Percent

Table 41 shows the results if import offers for external generation resources in the 2021/2022 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 $149.47 per MW-day, and the clearing quantity would have decreased to 163,320.8 MW. The clearing quantity of seasonal capacity would have remained the same at 715.5 MW. The ATSI clearing price would have remained the same at $171.33 per MW-day, and the clearing quantity would have remained the same at 8,007.3 MW. The clearing quantity of seasonal capacity for satisfying ATSI's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have remained the same at $165.73 per MW-day, and the clearing quantity would have remained the same at 29,288.5 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 1.0 MW. The PSEG clearing price would have remained the same at $204.29 per MW-day, and the clearing quantity would have remained the same at 5,367.6 MW. The clearing quantity of seasonal capacity for satisfying PSEG's reliability requirement would have remained the same at 1.0 MW. The BGE clearing price would have remained the same at $200.30 per MW-day, and the clearing quantity would have remained the same at 1,937.7 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW. The

ComEd clearing price would have decreased to $189.01 per MW-day, and the clearing quantity would have increased to 22,391.8 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have remained the same at 274.5 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If offers for external generation were reduced by 25 percent and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $9,589,433,567, an increase of $288,556,461, or 3.1 percent, compared to the actual results. From another perspective, the inclusion of all offers for external generation resources resulted in a 3.0 percent reduction in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been if offers for external generation had been reduced by 25 percent.[132]

Reduction by 75 Percent

Table 41 shows the results if import offers for external generation resources in the 2021/2022 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 EMAAC import limit would not have been binding. The RTO clearing price would have increased to $170.00 per MW-day, and the clearing quantity would have decreased to 162,656.6 MW. The clearing quantity of seasonal capacity would have remained the same at 715.5 MW. The ATSI clearing price would have increased to $171.33 per MW-day, and the clearing quantity would have remained the same at 8,007.3 MW. The clearing quantity of seasonal capacity for satisfying ATSI's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have increased to $170.00 per MW-day, and the clearing quantity would have increased to 29,318.8 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 1.0 MW. The PSEG clearing price would have remained the same at $204.29 per MW-day, and the clearing quantity would have remained the same at 5,367.6 MW. The clearing quantity of seasonal capacity for satisfying PSEG's reliability requirement would have remained the same at 1.0 MW. The BGE clearing price would have remained the same at $200.30 per MW-day, and the clearing quantity would have remained the same at 1,937.7 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have decreased to $189.01 per MW-day, and the clearing quantity would have increased to 22,391.8 MW.

[132] 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.

The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have remained the same at 274.5 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If offers for external generation were reduced by 75 percent and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $10,350,916,800, an increase of $1,050,039,694, or 11.3 percent, compared to the actual results. From another perspective, the inclusion of all offers for external generation resources resulted in a 10.1 percent reduction in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been if offers for external generation had been reduced by 75 percent.

Reduction by 100 Percent

Table 41 shows the results if import offers for external generation resources in the 2021/2022 RPM Base Residual Auction had been reduced by 100 percent and everything else had remained the same. All binding constraints would have remained the same, except that the ATSI import limit and the EMAAC import limit would not have been binding. The RTO clearing price would have increased to $172.64 per MW-day, and the clearing quantity would have decreased to 162,571.1 MW. The clearing quantity of seasonal capacity would have remained the same at 715.5 MW. The ATSI clearing price would have increased to $172.64 per MW-day, and the clearing quantity would have remained the same at 8,007.3 MW. The clearing quantity of seasonal capacity for satisfying ATSI's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have increased to $172.64 per MW-day, and the clearing quantity would have increased to 29,394.5 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 1.0 MW. The PSEG clearing price would have remained the same at $204.29 per MW-day, and the clearing quantity would have remained the same at 5,367.6 MW. The clearing quantity of seasonal capacity for satisfying PSEG's reliability requirement would have remained the same at 1.0 MW. The BGE clearing price would have remained the same at $200.30 per MW-day, and the clearing quantity would have remained the same at 1,937.7 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have decreased to $184.05 per MW-day, and the clearing quantity would have increased to 22,417.3 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have remained the same at 274.5 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If offers for external generation were reduced by 100 percent and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual

Auction would have been $10,427,509,062, an increase of $1,126,631,956, or 12.1 percent, compared to the actual results. From another perspective, the inclusion of all offers for external generation resources resulted in a 10.8 percent reduction in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been if offers for external generation had been reduced by 100 percent.

Impact of All DR, Seasonal Resources, and Capacity Imports (Scenario 17)

Table 42 shows the results if import offers for external generation resources had been reduced by 100 percent, there were no offers for DR or EE and no Seasonal resources in the 2021/2022 RPM Base Residual Auction and everything else had remained the same. The ATSI import limit would have been the only binding constraint. The RTO clearing price would have increased to $208.16 per MW-day, and the clearing quantity would have decreased to 157,509.1 MW. The clearing quantity of seasonal capacity would have decreased to 0 MW. The ATSI clearing price would have increased to $216.83 per MW-day, and the clearing quantity would have decreased to 7,595.6 MW. The clearing quantity of seasonal capacity for satisfying ATSI's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have increased to $208.16 per MW-day, and the clearing quantity would have increased to 29,638.6 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have decreased to 0 MW. The PSEG clearing price would have increased to $208.16 per MW-day, and the clearing quantity would have decreased to 5,127.4 MW. The clearing quantity of seasonal capacity for satisfying PSEG's reliability requirement would have decreased to 0 MW. The BGE clearing price would have increased to $208.16 per MW-day, and the clearing quantity would have increased to 2,839.3 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have increased to $208.16 per MW-day, and the clearing quantity would have increased to 22,707.1 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have decreased to 0 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If offers for external generation were reduced by 100 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 2021/2022 RPM Base Residual Auction would have been $11,997,162,266, an increase of $2,696,285,160, or 29.0 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 22.5 percent reduction in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been if offers for external generation had been reduced by 100 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 (Scenario 18)

PJM adjusts the VRR curve by adding the EE add back MW to the reliability requirement for each LDA. The EE add back MW is determined by PJM after a review of the EE measurement and verification plans.[133] If the ratio of the EE add back MW to cleared EE MW in the BRA exceeds a predetermined threshold, then PJM adjusts the EE add back MW and reruns the auction clearing a second and final time. For the 2021/2022 RPM Base Residual Auction, PJM cleared 2,832.0 MW of EE and the EE add back MW was equal to 3,912.9 for the aggregate RTO LDA. The resulting ratio, 1.38167373, did not exceed the threshold ratio of 1.606739475. Even though the threshold was not exceeded, the EE add back MW exceeded the EE cleared MW by 1,080.9 MW. Increasing demand due to the EE add back implementation had a significant impact on 2021/2022 RPM BRA results. 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 2021/2022 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 $132.68 per MW-day, and the clearing quantity would have decreased to 162,803.4 MW. The clearing quantity of Seasonal capacity would have remained the same at 715.5 MW. The ATSI clearing price would have decreased to $145.00 per MW-day, and the clearing quantity would have decreased to 7,985.5 MW. The clearing quantity of Seasonal capacity for satisfying ATSI's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have decreased to $165.00 per MW-day, and the clearing quantity would have decreased to 28,945.5 MW. The clearing quantity of Seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 1.0 MW. The PSEG clearing price would have decreased to $179.58 per MW-day, and the clearing quantity would have decreased to 5,269.3 MW. The clearing quantity of Seasonal capacity for satisfying PSEG's reliability requirement would have remained the same at 1.0 MW. The BGE clearing price would have decreased to $191.18 per MW-day, and the clearing quantity would have remained the same at 1,937.7 MW. The clearing quantity of Seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have decreased to $189.10 per MW-day, and the clearing quantity would have decreased to 22,312.5 MW. The clearing quantity of Seasonal capacity for satisfying ComEd's reliability requirement would have remained the same at 274.5 MW.

133 "PJM Manual 18: PJM Capacity Market," Rev. 40 (Feb. 22, 2018) at 32-34.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. 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 2021/2022 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $8,797,549,143, a decrease of $503,327,963, or 5.4 percent, compared to the actual results. From another perspective, the inconsistency between the EE cleared MW and the adjustment to the demand with the EE add back MW, resulted in a 5.7 percent increase in RPM revenues for the 2021/2022 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 (Scenario 19)

Table 44 shows the results if there were no offers for PRD in the 2021/2022 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 $142.60 per MW-day, and the clearing quantity would have increased to 164,099.0 MW. The clearing quantity of seasonal capacity would have remained the same at 715.5 MW. The ATSI clearing price would have remained the same at $171.33 per MW-day, and the clearing quantity would have remained the same at 8,007.3 MW. The clearing quantity of seasonal capacity for satisfying ATSI's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have increased to $172.33 per MW-day, and the clearing quantity would have increased to 29,318.8 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 1.0 MW. The PSEG clearing price would have remained the same at $204.29 per MW-day, and the clearing quantity would have remained the same at 5,367.6 MW. The clearing quantity of seasonal capacity for satisfying PSEG's reliability requirement would have remained the same at 1.0 MW. The BGE clearing price would have decreased to $180.50 per MW-day, and the clearing quantity would have increased to 2,221.2 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have decreased to $189.01 per MW-day, and the clearing quantity would have increased to 22,391.8 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have remained the same at 274.5 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If there were no offers for PRD in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $9,424,270,494, an increase of $123,393,388, or 1.3 percent, compared to the actual results. From another perspective, the inclusion of PRD resulted in a 1.3 percent reduction in RPM revenues for the

2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been without any PRD.

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

Impact of Nuclear Offers (Scenario 20)

Nuclear offer behavior changed in the 2021/2022 RPM Base Residual Auction compared to prior auctions. More nuclear capacity was offered at higher sell offer prices and fewer nuclear MW cleared.[134] (See Table 21, Table 22, and Table 30) To define an upper bound on the impact of nuclear offers, a scenario setting all nuclear offers to $0 per MW-day was analyzed. The MMU does not assert that a $0 per MW-day sell offer was a competitive offer for all nuclear resources.

Table 46 shows the results of the 2021/2022 RPM Base Residual Auction had all nuclear offers been replaced with $0 per MW-day and everything else had remained the same. The EMAAC, PSEG, and BGE import constraints would have remained binding and the DEOK import constraint would have been binding. The ATSI and ComEd import constraints would not be binding. The RTO clearing price would have decreased to $71.48 per MW-day, and the clearing quantity would have increased to 165,844.3 MW. The clearing quantity of seasonal capacity would have decreased to 587.6 MW. The ATSI clearing price would have decreased to $71.48 per MW-day, and the clearing quantity would have increased to 8,603.4 MW. The clearing quantity of seasonal capacity for satisfying ATSI's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have decreased to $125.94 per MW-day, and the clearing quantity would have increased to 29,598.6 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 1.0 MW. The PSEG clearing price would have remained the same at $204.29 per MW-day, and the clearing quantity would have remained the same at 5,367.6 MW. The clearing quantity of seasonal capacity for satisfying PSEG's reliability requirement would have remained the same at 1.0 MW. The BGE clearing price would have remained the same at $200.30 per MW-day, and the clearing quantity would have remained the same at 1,937.7 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have decreased to $71.48 per MW-day, and the clearing quantity would have increased to 24,499.4 MW. The clearing quantity of seasonal

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

capacity for satisfying ComEd's reliability requirement would have decreased to 154.4 MW. The DEOK clearing price would have decreased to $128.47 per MW-day, and the clearing quantity would have decreased to 2,636.3 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 2021/2022 RPM Base Residual Auction were $9,300,877,106. If all nuclear offers were replaced by $0 per MW-day in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $5,215,048,770, a decrease of $4,085,828,337, or 43.9 percent, compared to the actual results. From another perspective, nuclear offers at levels exceeding $0 per MW-day resulted in a 78.3 percent increase in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been had all nuclear offers been at $0 per MW-day.

Noncompetitive Offers (Scenario 21)

The MMU identified noncompetitive offers that had a significant impact on the 2021/2022 RPM Base Residual Auction results.

Some participants' offers were above the competitive level. The MMU recognizes that these market participants followed the capacity market rules by offering at less than the stated offer cap of Net CONE times B. But Net CONE times B is not a competitive offer when the expected number of performance assessment intervals is zero or a very small number and the non-performance charge rate is defined as Net CONE/30. Under these circumstances, a competitive offer, under the logic defined in PJM's capacity performance filing, is net ACR. That is the way in which most market participants offered in this and prior capacity performance auctions.

The FERC approved PJM tariff defines the offer cap as Net CONE times B, rather than including the full logic supporting the definition of the offer cap under the capacity performance paradigm. If the tariff had defined the offer cap consistent with PJM's filing in the capacity performance matter, the offer cap would have been net ACR rather than Net CONE times B.

The PJM tariff defines the balancing ratio (B) used in the default offer cap as the average of balancing ratios during the actual performance assessment intervals that occurred during the three calendar years preceding the auction.[135] PJM did not experience any

[135] OATT Attachment DD § 6.4(a).

performance assessment intervals during the three year period that preceded the 2021/2022 RPM Base Residual Auction and the balancing ratio calculation was not feasible. PJM resolved the balancing ratio issue by changing the tariff to state that the balancing ratio for the 2021/2022 RPM Base Residual Auction would equal the balancing ratio value used for the 2020/2021 RPM Base Residual Auction.[136] PJM did not propose any updates to the nonperformance charge rate or the default offer cap definition of net CONE times B. In doing so, PJM continued to assume an expected 30 hours, or 360 intervals, of PAIs for the 2021/2022 delivery year. This assumption is not consistent with the recent history of emergency actions in the PJM energy market. The correct way to account for the lack of performance assessment intervals during the three year history would have been to recognize that this means that unit specific net ACR is the offer cap under the capacity performance construct. This would have been consistent with a market participant having an expectation of a very low number of performance assessment intervals. This would have been consistent with the competitive offer calculation logic that PJM filed in response to a deficiency letter issued by the Commission in the Capacity Performance docket.[137]

Table 47 shows the results if the noncompetitive offers identified by the MMU had been capped at net ACR for the 2021/2022 RPM Base Residual Auction. All binding constraints would have remained the same except that the BGE import constraint would not have been binding and the DEOK import constraint would have been binding. The RTO clearing price would have decreased to $124.40 per MW-day, and the clearing quantity would have increased to 164,132.1 MW. The clearing quantity of seasonal capacity would have remained the same at 715.5 MW. The ATSI clearing price would have decreased to $169.65 per MW-day, and the clearing quantity would have increased to 8,013.1 MW. The clearing quantity of seasonal capacity for satisfying ATSI's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have decreased to $155.93 per MW-day, and the clearing quantity would have increased to 29,364.9 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 1.0 MW. The PSEG clearing price would have remained the same at $204.29 per MW-day, and the clearing quantity would have remained the same at 5,367.6 MW. The clearing quantity of seasonal capacity for satisfying PSEG's reliability requirement would have remained the same at 1.0 MW. The BGE clearing price would have decreased to $124.40 per MW-day,

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136 *See* PJM. "Reliability Pricing Model Offer Cap Tariff Revision for 2018 Base Residual Auction," Docket No. ER18-262 (November 7, 2017).

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

and the clearing quantity would have increased to 2,492.0 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have decreased to $130.04 per MW-day, and the clearing quantity would have increased to 22,695.5 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have remained the same at 274.5 MW. The DEOK clearing price would have decreased to $128.47 per MW-day, and the clearing quantity would have decreased to 2,636.3 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 2021/2022 RPM Base Residual Auction were $9,300,877,106. If the identified noncompetitive offers had been capped at net ACR in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $8,070,050,631, a decrease of $1,230,826,475, or 13.2 percent, compared to the actual results. From another perspective, the noncompetitive offers resulted in a 15.3 percent increase in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been had the noncompetitive offers been capped at net ACR.

Tables and Figures for RTO Market

Table 9 RTO offer statistics: 2021/2022 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	198,147.3	189,028.5		
DR capacity	11,641.3	12,686.7		
EE capacity	2,728.9	2,975.2		
Generation winter capacity	534.7	534.7		
Total internal RTO capacity	213,052.2	205,225.1		
FRR	(14,578.3)	(13,702.1)		
Imports	5,214.0	4,911.6		
RPM capacity	203,687.9	196,434.6		
Exports	(1,319.8)	(1,295.0)		
FRR optional	(17.3)	(16.1)		
Excused Existing Generation Capacity Resources	(4,110.3)	(3,017.5)		
Unoffered Planned Generation Capacity Resources	(3,141.2)	(3,005.3)		
Unoffered Intermittent Resources	(1,482.8)	(1,397.6)		
Unoffered Capacity Storage Resources	(580.9)	(574.9)		
Unoffered generation winter capacity	(249.3)	(249.3)		
Unoffered DR and EE	(812.4)	(894.1)		
Available	191,973.9	185,984.8	100.0%	100.0%
Generation offered	178,410.1	171,249.8	92.9%	92.1%
DR offered	10,551.3	11,494.0	5.5%	6.2%
EE offered	2,574.6	2,803.2	1.3%	1.5%
Total offered	191,536.1	185,547.0	99.8%	99.8%
Unoffered Existing Generation Capacity Resources	437.8	437.8	0.2%	0.2%

Table 10 Reserve margin: 2021/2022 RPM Base Residual Auction

	Reserve Margin Calculation	
Forecast peak load	152,647.4	A
FRR peak load	12,107.1	B
PRD	510.0	C
IRM	15.8%	D
Pool-wide average EFORd	5.89%	E
Cleared UCAP (generation and DR)	160,795.3	F
Cleared ICAP (generation and DR)	170,858.9	G=F/(1-E)
RPM peak load	140,030.3	H=A-B-C
Reserve margin	22.0%	J=(G/H)-1
Reserve cleared in excess of IRM	6.2%	J-D

Table 11 Net excess: 2021/2022 RPM Base Residual Auction

	UCAP (MW)						
	RTO	EMAAC	PSEG	ATSI	ComEd	BGE	
Cleared generation and DR plus make whole	160,795.3	28,671.5	5,127.5	7,859.1	21,587.6	1,833.3	A
CETL	NA	9,000.0	6,902.0	8,439.0	5,574.0	6,005.0	B
Reliability requirement	166,355.1	35,994.0	11,501.0	15,598.0	26,112.0	7,910.0	C
FRR peak load	12,107.1	0.0	0.0	0.0	0.0	0.0	D
PRD	510.0	75.0	0.0	0.0	0.0	240.0	E
FPR	1.0898	1.0898	1.0898	1.0898	1.0898	1.0898	F
Reliability requirement adjusted for FRR and PRD	152,605.0	35,912.3	11,501.0	15,598.0	26,112.0	7,648.4	G=C-D*F-E*F
Net excess/(deficit)	8,190.3	1,759.2	528.5	700.1	1,049.6	189.9	A+B-G

Table 12 Net load prices: 2021/2022 RPM Base Residual Auction

	$ per MW-day					
	RTO	EMAAC	PSEG	ATSI	ComEd	BGE
Resource clearing price	$140.00	$165.73	$204.29	$171.33	$195.55	$200.30
Preliminary zonal capacity price	$140.02	$165.75	$204.31	$171.35	$195.57	$200.32
Adjusted preliminary zonal capacity price	$140.53	$166.31	$204.92	$171.86	$196.08	$203.19
Base zonal CTR credit rate	$0.00	$3.23	$20.88	$13.87	$3.40	$41.57
Preliminary net load price	$140.53	$163.08	$184.03	$157.99	$192.69	$161.62

Table 13 Capacity modifications (ICAP): 2021/2022 RPM Base Residual Auction[138]

	ICAP (MW)					
	RTO	EMAAC	PSEG	ATSI	ComEd	BGE
Generation increases	3,403.8	110.4	38.4	24.7	178.7	0.0
Generation decreases	(1,093.2)	(32.5)	(0.6)	(40.7)	(20.8)	0.0
Capacity modifications net increase/(decrease)	2,310.6	77.9	37.8	(16.0)	157.9	0.0
DR increases	2,271.3	262.4	75.0	350.6	199.3	5.6
DR decreases	(1,303.0)	(230.4)	(42.6)	(323.7)	(118.7)	(100.6)
DR net increase/(decrease)	968.3	32.0	32.4	26.9	80.6	(95.0)
EE increases	1,827.1	495.8	196.4	146.4	239.2	30.5
EE decreases	(1,283.0)	(240.5)	(66.6)	(48.3)	(267.2)	(80.6)
EE modifications increase/(decrease)	544.1	255.3	129.8	98.1	(28.0)	(50.1)
Net internal capacity increase/(decrease)	3,823.0	365.2	200.0	109.0	210.5	(145.1)

138 Only cap mods that had a start date on or before June 1, 2021 and DR and EE plans for the 2021/2022 RPM Base Residual Auction are included.

Table 14 Capacity modifications (UCAP): 2021/2022 RPM Base Residual Auction

	UCAP (MW)					
	RTO	EMAAC	PSEG	ATSI	ComEd	BGE
Generation increases	3,335.0	106.8	35.3	58.3	178.0	0.0
Generation decreases	(868.0)	(27.3)	(0.6)	(39.4)	(20.2)	0.0
Capacity modifications net increase/(decrease)	2,467.0	79.5	34.7	18.9	157.8	0.0
DR increases	2,474.3	286.0	81.7	381.9	217.1	6.1
DR decreases	(1,418.4)	(250.4)	(46.3)	(352.5)	(129.3)	(109.7)
DR net increase/(decrease)	1,055.9	35.6	35.4	29.4	87.8	(103.6)
EE increases	1,990.3	540.2	214.2	159.5	260.4	33.2
EE decreases	(1,395.9)	(261.0)	(72.4)	(52.5)	(291.1)	(87.9)
EE modifications increase/(decrease)	594.4	279.2	141.8	107.0	(30.7)	(54.7)
Net capacity/DR/EE modifications increase/(decrease)	4,117.3	394.3	211.9	155.3	214.9	(158.3)
EFORd effect	(164.6)	226.8	34.2	(235.7)	118.4	55.5
DR and EE effect	9.3	1.1	0.3	1.0	1.8	0.5
Net internal capacity increase/(decrease)	3,962.0	622.2	246.4	(79.4)	335.1	(102.3)

Table 15 Winter capacity modifications (ICAP): 2021/2022 RPM Base Residual Auction

	ICAP (MW)					
	RTO	EMAAC	PSEG	ATSI	ComEd	BGE
Generation increases	359.6	0.0	0.0	0.0	179.9	0.0
Generation decreases	(106.5)	0.0	0.0	0.0	(67.4)	0.0
Capacity modifications net increase/(decrease)	253.1	0.0	0.0	0.0	112.5	0.0
DR increases	0.0	0.0	0.0	0.0	0.0	0.0
DR decreases	0.0	0.0	0.0	0.0	0.0	0.0
DR net increase/(decrease)	0.0	0.0	0.0	0.0	0.0	0.0
EE increases	0.0	0.0	0.0	0.0	0.0	0.0
EE decreases	0.0	0.0	0.0	0.0	0.0	0.0
EE modifications increase/(decrease)	0.0	0.0	0.0	0.0	0.0	0.0
Net internal capacity increase/(decrease)	253.1	0.0	0.0	0.0	112.5	0.0

Table 16 Winter capacity modifications (UCAP): 2021/2022 RPM Base Residual Auction

	UCAP (MW)					
	RTO	EMAAC	PSEG	ATSI	ComEd	BGE
Generation increases	359.6	0.0	0.0	0.0	179.9	0.0
Generation decreases	(106.5)	0.0	0.0	0.0	(67.4)	0.0
Capacity modifications net increase/(decrease)	253.1	0.0	0.0	0.0	112.5	0.0
DR increases	0.0	0.0	0.0	0.0	0.0	0.0
DR decreases	0.0	0.0	0.0	0.0	0.0	0.0
DR net increase/(decrease)	0.0	0.0	0.0	0.0	0.0	0.0
EE increases	0.0	0.0	0.0	0.0	0.0	0.0
EE decreases	0.0	0.0	0.0	0.0	0.0	0.0
EE modifications increase/(decrease)	0.0	0.0	0.0	0.0	0.0	0.0
Net capacity/DR/EE modifications increase/(decrease)	253.1	0.0	0.0	0.0	112.5	0.0
EFORd effect	0.0	0.0	0.0	0.0	0.0	0.0
DR and EE effect	0.0	0.0	0.0	0.0	0.0	0.0
Net internal capacity increase/(decrease)	253.1	0.0	0.0	0.0	112.5	0.0

Table 17 Installed and offered generation capacity by parent company: 2021/2022 RPM Base Residual Auction

Parent Company	ICAP (MW)	Percent of Total ICAP	Offered ICAP (MW)	Percent of Total Offered ICAP
Dominion Resources, Inc.	22,866.2	11.2%	22,797.5	12.8%
Exelon Corporation	22,353.0	11.0%	21,337.1	12.0%
American Electric Power Company, Inc.	16,922.3	8.3%	3,039.1	1.7%
NRG Energy, Inc.	15,339.0	7.5%	15,300.6	8.6%
FirstEnergy Corp.	14,857.0	7.3%	13,696.9	7.7%

Table 18 Offered and cleared capacity by LDA, resource type, and season type: 2021/2022 RPM Base Residual Auction

		Offered UCAP (MW)			Cleared UCAP (MW)		
LDA	Resource Type	Annual	Summer	Winter	Annual	Summer	Winter
RTO	GEN	170,841.5	53.5	354.8	149,615.6	27.2	354.8
RTO	DR	11,094.6	399.4	0.0	10,673.5	228.0	0.0
RTO	EE	2,649.0	154.2	0.0	2,622.7	105.5	0.0
EMAAC	GEN	29,931.3	2.9	0.5	27,377.9	0.9	0.5
EMAAC	DR	1,320.9	68.7	0.0	1,315.8	31.8	0.0
EMAAC	EE	605.7	21.5	0.0	593.8	11.7	0.0
PSEG	GEN	5,300.5	1.2	0.5	4,727.9	0.0	0.5
PSEG	DR	408.3	7.6	0.0	407.9	0.0	0.0
PSEG	EE	241.8	8.8	0.0	230.8	4.7	0.0
ATSI	GEN	10,663.6	0.0	0.0	6,723.0	0.0	0.0
ATSI	DR	1,221.2	0.0	0.0	1,142.4	0.0	0.0
ATSI	EE	141.9	5.7	0.0	141.9	3.2	0.0
ComEd	GEN	24,790.1	0.0	136.1	19,589.8	0.0	136.1
ComEd	DR	1,906.0	86.8	0.0	1,837.3	80.9	0.0
ComEd	EE	669.3	59.6	0.0	656.5	57.5	0.0
BGE	GEN	2,989.5	0.0	0.0	1,639.3	0.0	0.0
BGE	DR	216.8	76.9	0.0	194.8	42.4	0.0
BGE	EE	103.6	0.7	0.0	103.6	0.4	0.0

Table 19 Weighted average sell offer prices by LDA, resource type, and season type: 2021/2022 RPM Base Residual Auction

LDA	Resource Type	Weighted-Average ($ per MW-day UCAP) Annual	Summer	Winter
RTO	GEN	$53.21	$5.03	$62.11
RTO	DR	$39.15	$9.55	
RTO	EE	$40.51	$3.54	
EMAAC	GEN	$56.82	$58.77	$60.00
EMAAC	DR	$44.27	$12.25	
EMAAC	EE	$72.73	$1.50	
PSEG	GEN	$83.40	$139.58	$60.00
PSEG	DR	$40.45	$70.23	
PSEG	EE	$91.49	$3.69	
ATSI	GEN	$107.34		
ATSI	DR	$42.79		
ATSI	EE	$2.54	$0.00	
ComEd	GEN	$80.40		$32.14
ComEd	DR	$43.68	$2.83	
ComEd	EE	$17.44	$0.00	
BGE	GEN	$157.57		
BGE	DR	$52.06	$0.00	
BGE	EE	$0.14	$0.00	

Table 20 Offered capacity by resource type, season type and price range as percent of net CONE times B: 2021/2022 RPM Base Residual Auction[139]

	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	17,981.2	123,381.1	29,479.2	49.4	3.2	1.0	112.8	167.5	74.5
DR	530.3	9,792.0	772.3	350.6	48.8	0.0	0.0	0.0	0.0
EE	1,192.1	1,239.3	217.6	146.6	7.3	0.3	0.0	0.0	0.0

139 Data aggregated based on PJM confidentiality rules.

Table 21 Cleared MW by zone and resource type/fuel source: 2021/2022 RPM Base Residual Auction[140]

	Cleared UCAP (MW)										
Zone	DR	EE	Coal	Gas	Hydro	Nuclear	Oil	Solar	Solid Waste	Wind	Total
AECO	83.4	40.6	453.2	1,049.3	0.0	0.0	22.9	12.3	0.0	0.0	1,661.7
AEP	1,680.4	164.8	5,032.2	9,496.9	52.3	93.0	0.0	0.0	43.3	247.8	16,810.7
AP	1,019.4	54.2	4,859.4	3,943.7	123.8	0.0	0.0	8.5	0.0	127.1	10,136.1
ATSI	1,142.4	145.1	2,103.8	4,205.5	0.0	0.0	413.7	0.0	0.0	0.0	8,010.5
BGE	237.2	104.0	1,158.7	227.5	0.0	1,687.3	198.1	0.0	55.0	0.0	3,667.8
ComEd	1,918.2	714.0	4,850.9	9,024.8	0.0	5,164.7	210.8	0.0	0.0	474.7	22,358.1
DAY	227.7	59.5	0.0	1,317.3	0.0	0.0	32.9	0.0	0.0	0.0	1,637.4
DEOK	201.8	89.1	1,721.8	584.9	109.0	0.0	39.5	0.0	0.0	0.0	2,746.1
DLCO	135.4	27.6	508.5	199.7	0.0	0.0	9.7	0.0	0.0	0.0	880.9
Dominion	1,136.1	559.2	3,774.0	12,674.1	3,115.4	3,523.3	992.7	348.0	153.4	67.5	26,343.7
DPL	233.8	47.1	396.5	4,056.1	0.0	0.0	644.6	90.5	0.0	0.0	5,468.6
EKPC	159.4	0.0	1,648.1	1,233.3	131.2	0.0	0.0	0.0	0.0	0.0	3,172.0
External	0.0	0.0	2,981.2	338.8	633.4	98.4	0.0	0.0	0.0	0.0	4,051.8
JCPL	170.3	176.8	0.0	2,900.5	278.0	0.0	199.9	59.0	0.0	0.0	3,784.5
Met-Ed	360.4	21.4	113.5	2,497.3	16.0	0.0	282.9	0.0	50.1	0.0	3,341.6
PECO	446.4	98.0	0.0	4,145.2	597.0	4,430.6	787.5	0.0	98.3	0.0	10,603.0
PENELEC	364.5	17.5	5,993.1	2,122.4	539.7	0.0	52.9	0.0	40.4	93.1	9,223.6
Pepco	286.2	98.9	2,297.3	3,548.3	0.0	0.0	268.9	0.0	46.5	0.0	6,546.1
PPL	684.7	67.6	3,301.4	7,837.0	625.7	2,491.1	294.7	7.6	8.5	50.3	15,368.6
PSEG	407.9	235.5	0.0	4,544.1	3.0	2,429.5	0.0	17.3	164.0	0.0	7,801.3
RECO	5.8	7.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13.4
Total	10,901.5	2,728.2	41,193.6	75,946.7	6,224.5	19,917.9	4,451.7	543.2	659.5	1,060.5	163,627.3

140 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 22 Uncleared generation offers by technology type and age: 2021/2022 RPM Base Residual Auction[141] [142]

	Uncleared UCAP (MW)		
Technology Type	Less Than or Equal to 40 Years Old	Greater than 40 Years Old	Total
Coal Fired	1,684.9	4,321.9	6,006.8
Combined cycle	1,310.1	0.0	1,310.1
Combustion turbine	636.2	219.5	855.7
Nuclear	6,821.4	3,821.3	10,642.7
Oil or gas steam	0.0	1,801.9	1,801.9
Other	143.7	491.4	635.1
Total	10,596.3	10,656.0	21,252.3

Table 23 Uncleared generation resources in multiple auctions[143] [144]

	2021/2022		2020/2021 Results for Same Set of Resources		2019/2020 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	6,006.8	64	4,370.0	38	2,300.3	27
Combined cycle	1,310.1	48	751.9	10	229.9	8
Combustion turbine	855.7	83	827.7	59	496.9	31
Other	13,079.7	74	1,944.6	30	1,684.4	13
Total	21,252.3	269	7,894.2	137	4,711.5	79

141 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 2021/2022 BRA, waste coal resources are included in the coal fired category.

142 Data aggregated based on PJM confidentiality rules.

143 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 2021/2022 BRA, waste coal resources are included in the coal fired category.

144 Data aggregated based on PJM confidentiality rules.

Table 24 PJM LDA CETL and CETO values: 2020/2021 and 2021/2022 RPM Base Residual Auctions

	2020/2021			2021/2022			Change			
							CETO		CETL	
LDA	CETO	CETL	CETL to CETO Ratio	CETO	CETL	CETL to CETO Ratio	MW	Percent	MW	Percent
MAAC	(7,000.0)	4,218.0	(60%)	(8,870.0)	4,019.0	(45%)	(1,870.0)	27%	(199.0)	(5%)
EMAAC	3,650.0	8,800.0	241%	2,500.0	9,000.0	360%	(1,150.0)	(32%)	200.0	2%
SWMAAC	2,900.0	9,802.0	338%	2,870.0	9,082.0	316%	(30.0)	(1%)	(720.0)	(7%)
PSEG	5,900.0	8,001.0	136%	5,620.0	6,902.0	123%	(280.0)	(5%)	(1,099.0)	(14%)
PSEG North	2,620.0	4,264.0	163%	2,410.0	3,180.0	132%	(210.0)	(8%)	(1,084.0)	(25%)
DPL South	1,230.0	1,872.0	152%	1,080.0	1,624.0	150%	(150.0)	(12%)	(248.0)	(13%)
Pepco	1,540.0	7,625.0	495%	1,550.0	6,915.0	446%	10.0	1%	(710.0)	(9%)
ATSI	4,660.0	9,889.0	212%	6,020.0	8,439.0	140%	1,360.0	29%	(1,450.0)	(15%)
ATSI Cleveland	3,540.0	5,605.0	158%	4,100.0	5,256.0	128%	560.0	16%	(349.0)	(6%)
ComEd	640.0	4,064.0	635%	(640.0)	5,574.0	(871%)	(1,280.0)	(200%)	1,510.0	37%
BGE	4,410.0	6,244.0	142%	4,470.0	6,005.0	134%	60.0	1%	(239.0)	(4%)
PPL	(1,010.0)	7,084.0	(701%)	(850.0)	6,609.0	(778%)	160.0	(16%)	(475.0)	(7%)
DAY	2,550.0	3,401.0	133%	2,480.0	3,502.0	141%	(70.0)	(3%)	101.0	3%
DEOK	3,650.0	5,072.0	139%	3,110.0	4,959.0	159%	(540.0)	(15%)	(113.0)	(2%)

Table 25 Changes to PJM LDA CETL values

LDA	CETL Values 2020/2021 BRA	Proposed CETL Values (August 2017)	CETL Values 2021/2022 BRA
MAAC	4,218	3,118	4,019
EMAAC	8,800	8,300	9,000
SWMAAC	9,802		9,082
PSEG	8,001	6,474	6,902
PSEG North	4,264	2,955	3,180
DPL South	1,872		1,624
PEPCO	7,625		6,915
ATSI	9,889		8,439
ATSI-Cleveland	5,605		5,256
ComEd	4,064		5,574
BGE	6,244		6,005
PPL	7,084		6,609
DAY	3,401		3,502
DEOK	5,072		4,959

Table 26 Impact of ComEd CETL change: 2021/2022 RPM Base Residual Auction

Scenario 1

		Actual Auction Results		ComEd CETL	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$140.00	162,911.8	$112.75	163,793.4
	Summer	$140.00	715.5	$112.75	715.5
	Winter	$140.00	715.5	$112.75	715.5
RTO Total			163,627.3		164,508.9
ATSI	Annual	$171.33	8,007.3	$171.33	8,007.3
	Summer	$171.33	6.3	$171.33	8.7
	Winter	$171.33	0.0	$171.33	0.0
ATSI Total			8,007.3		8,007.3
EMAAC	Annual	$165.73	29,287.5	$165.73	29,287.5
	Summer	$165.73	88.0	$165.73	20.4
	Winter	$165.73	1.0	$165.73	1.0
EMAAC Total			29,288.5		29,288.5
PSEG	Annual	$204.29	5,366.6	$204.29	5,366.6
	Summer	$204.29	9.3	$204.29	9.7
	Winter	$204.29	1.0	$204.29	1.0
PSEG Total			5,367.6		5,367.6
BGE	Annual	$200.30	1,937.7	$180.50	1,959.6
	Summer	$200.30	85.0	$180.50	153.1
	Winter	$200.30	0.0	$180.50	0.0
BGE Total			1,937.7		1,959.6
ComEd	Annual	$195.55	22,083.6	$189.10	23,630.8
	Summer	$195.55	274.5	$189.10	274.5
	Winter	$195.55	274.5	$189.10	274.5
ComEd Total			22,358.1		23,905.3
DEOK	Annual	$140.00	2,733.3	$128.47	2,636.3
	Summer	$140.00	25.4	$128.47	44.7
	Winter	$140.00	0.0	$128.47	0.0
DEOK Total			2,733.3		2,636.3

Table 27 Impact of PSEG CETL adjustment: 2021/2022 RPM Base Residual Auction Scenario 2

		Actual Auction Results		PSEG CETL Adjustment	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$140.00	162,911.8	$140.00	162,911.8
	Summer	$140.00	715.5	$140.00	715.5
	Winter	$140.00	715.5	$140.00	715.5
RTO Total			163,627.3		163,627.3
ATSI	Annual	$171.33	8,007.3	$171.33	8,007.3
	Summer	$171.33	6.3	$171.33	6.3
	Winter	$171.33	0.0	$171.33	0.0
ATSI Total			8,007.3		8,007.3
EMAAC	Annual	$165.73	29,287.5	$165.47	29,289.5
	Summer	$165.73	88.0	$165.47	88.2
	Winter	$165.73	1.0	$165.47	1.0
EMAAC Total			29,288.5		29,290.5
PSEG	Annual	$204.29	5,366.6	$206.58	5,561.2
	Summer	$204.29	9.3	$206.58	9.3
	Winter	$204.29	1.0	$206.58	1.0
PSEG Total			5,367.6		5,562.2
BGE	Annual	$200.30	1,937.7	$200.30	1,937.7
	Summer	$200.30	85.0	$200.30	85.0
	Winter	$200.30	0.0	$200.30	0.0
BGE Total			1,937.7		1,937.7
ComEd	Annual	$195.55	22,083.6	$195.55	22,083.6
	Summer	$195.55	274.5	$195.55	274.5
	Winter	$195.55	274.5	$195.55	274.5
ComEd Total			22,358.1		22,358.1

Table 28 Impact of load forecast reduction: 2021/2022 RPM Base Residual Auction Scenario 3

		Actual Auction Results		Reduce Load Forecast by 5.8 percent	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$140.00	162,911.8	$80.00	154,726.3
	Summer	$140.00	715.5	$80.00	623.5
	Winter	$140.00	715.5	$80.00	623.5
RTO Total			163,627.3		155,349.8
ATSI	Annual	$171.33	8,007.3	$226.40	6,889.1
	Summer	$171.33	6.3	$226.40	5.4
	Winter	$171.33	0.0	$226.40	0.0
ATSI Total			8,007.3		6,889.1
EMAAC	Annual	$165.73	29,287.5	$139.46	27,309.0
	Summer	$165.73	88.0	$139.46	10.3
	Winter	$165.73	1.0	$139.46	1.0
EMAAC Total			29,288.5		27,310.0
PSEG	Annual	$204.29	5,366.6	$160.00	4,775.5
	Summer	$204.29	9.3	$160.00	5.3
	Winter	$204.29	1.0	$160.00	1.0
PSEG Total			5,367.6		4,776.5
BGE	Annual	$200.30	1,937.7	$178.77	1,492.6
	Summer	$200.30	85.0	$178.77	110.8
	Winter	$200.30	0.0	$178.77	0.0
BGE Total			1,937.7		1,492.6
ComEd	Annual	$195.55	22,083.6	$198.48	20,498.2
	Summer	$195.55	274.5	$198.48	274.5
	Winter	$195.55	274.5	$198.48	274.5
ComEd Total			22,358.1		20,772.7
DEOK	Annual	$140.00	2,733.3	$107.23	2,284.4
	Summer	$140.00	25.4	$107.23	0.0
	Winter	$140.00	0.0	$107.23	0.0
DEOK Total			2,733.3		2,284.4

Table 29 Impact of one percent rightward shift in the VRR curve: 2021/2022 RPM Base Residual Auction

Scenario 4

		Actual Auction Results		Impact of 1.0 percent VRR shift	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$140.00	162,911.8	$129.43	161,931.0
	Summer	$140.00	715.5	$129.43	715.5
	Winter	$140.00	715.5	$129.43	715.5
RTO Total			163,627.3		162,646.5
ATSI	Annual	$171.33	8,007.3	$145.00	7,963.5
	Summer	$171.33	6.3	$145.00	6.3
	Winter	$171.33	0.0	$145.00	0.0
ATSI Total			8,007.3		7,963.5
EMAAC	Annual	$165.73	29,287.5	$165.00	28,982.4
	Summer	$165.73	88.0	$165.00	88.2
	Winter	$165.73	1.0	$165.00	1.0
EMAAC Total			29,288.5		28,983.4
PSEG	Annual	$204.29	5,366.6	$194.47	5,290.5
	Summer	$204.29	9.3	$194.47	9.3
	Winter	$204.29	1.0	$194.47	1.0
PSEG Total			5,367.6		5,291.5
BGE	Annual	$200.30	1,937.7	$178.77	1,895.2
	Summer	$200.30	85.0	$178.77	85.0
	Winter	$200.30	0.0	$178.77	0.0
BGE Total			1,937.7		1,895.2
ComEd	Annual	$195.55	22,083.6	$184.04	21,917.4
	Summer	$195.55	274.5	$184.04	274.5
	Winter	$195.55	274.5	$184.04	274.5
ComEd Total			22,358.1		22,191.9

Table 30 Offers greater than $35.00 per MW-day in total RTO supply curve: 2021/2022 RPM Base Residual Auction[145] [146]

Technology/Resource Type	Offered UCAP (MW)	Percent of Offers
Coal fired	23,157.3	30.8%
Nuclear	14,987.2	19.9%
Combined cycle	13,586.8	18.1%
Combustion turbine	8,508.6	11.3%
Oil or gas steam	7,297.5	9.7%
Demand Resource	3,824.8	5.1%
Hydro	1,890.8	2.5%
Energy Efficiency Resource	1,123.1	1.5%
Wind	419.4	0.6%
Other generation	235.7	0.3%
Solar	202.7	0.3%
Total	75,234.0	100.0%

145 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 2021/2022 BRA, waste coal resources are included in the coal fired category.

146 Data aggregated based on PJM confidentiality rules.

Table 31 DR and EE statistics by LDA: 2020/2021 and 2021/2022 RPM Base Residual Auctions

		2020/2021 BRA			2021/2022 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	8,373.2	9,113.0	7,677.1	10,551.3	11,494.0	10,901.5	2,178.1	26.0%	2,380.9	26.1%	3,224.4	42.0%
RTO	EE	1,877.7	2,042.4	1,659.2	2,574.6	2,803.2	2,728.2	696.9	37.1%	760.7	37.2%	1,069.0	64.4%
MAAC	DR	2,807.8	3,054.4	2,606.4	3,213.4	3,498.6	3,280.7	405.6	14.4%	444.2	14.5%	674.2	25.9%
MAAC	EE	590.0	641.0	526.9	871.6	948.2	914.8	281.6	47.7%	307.2	47.9%	387.9	73.6%
EMAAC	DR	1,097.5	1,193.3	1,085.7	1,276.1	1,389.6	1,347.6	178.6	16.3%	196.2	16.4%	261.9	24.1%
EMAAC	EE	289.5	314.0	288.7	576.5	627.2	605.5	287.0	99.1%	313.2	99.8%	316.8	109.7%
SWMAAC	DR	520.4	566.2	395.0	584.4	635.8	523.4	64.0	12.3%	69.6	12.3%	128.5	32.5%
SWMAAC	EE	199.1	216.8	179.8	189.2	206.1	202.9	(9.8)	(4.9%)	(10.7)	(4.9%)	23.1	12.8%
DPL South	DR	71.1	77.2	72.6	64.3	70.0	66.3	(6.8)	(9.5%)	(7.2)	(9.3%)	(6.3)	(8.7%)
DPL South	EE	7.9	8.6	8.6	13.5	14.5	13.6	5.6	70.9%	5.9	68.6%	5.0	58.1%
PSEG	DR	311.6	338.9	325.9	381.7	415.9	407.9	70.1	22.5%	76.9	22.7%	82.0	25.2%
PSEG	EE	94.5	102.5	92.8	230.0	250.6	235.5	135.5	143.4%	148.0	144.4%	142.7	153.7%
PSEG North	DR	132.9	144.3	141.4	178.5	194.5	188.6	45.7	34.4%	50.2	34.8%	47.2	33.4%
PSEG North	EE	18.9	20.4	17.9	70.3	76.6	71.6	51.5	272.7%	56.3	276.1%	53.7	300.1%
Pepco	DR	235.0	255.7	183.9	314.3	342.1	286.2	79.3	33.7%	86.5	33.8%	102.3	55.6%
Pepco	EE	73.3	79.7	60.8	93.5	101.8	98.9	20.2	27.6%	22.1	27.8%	38.1	62.7%
ATSI	DR	735.8	800.6	688.6	1,120.8	1,221.2	1,142.4	385.0	52.3%	420.6	52.5%	453.8	65.9%
ATSI	EE	45.9	49.8	32.5	135.5	147.6	145.1	89.6	195.0%	97.9	196.6%	112.6	346.3%
ATSI Cleveland	DR	184.6	200.9	168.9	263.6	287.2	272.8	79.0	42.8%	86.3	42.9%	103.9	61.5%
ATSI Cleveland	EE	0.4	0.4	0.4	33.2	36.2	36.2	32.8	8,187.6%	35.8	8,937.6%	35.8	8,937.6%
ComEd	DR	1,485.2	1,617.4	1,469.8	1,828.7	1,992.8	1,918.2	343.5	23.1%	375.4	23.2%	448.5	30.5%
ComEd	EE	665.6	724.7	671.2	668.9	728.9	714.0	3.3	0.5%	4.2	0.6%	42.8	6.4%
BGE	DR	285.4	310.5	211.0	270.1	293.7	237.2	(15.3)	(5.4%)	(16.8)	(5.4%)	26.2	12.4%
BGE	EE	125.8	137.1	119.1	95.8	104.3	104.0	(30.0)	(23.9%)	(32.8)	(23.9%)	(15.0)	(12.6%)
PPL	DR	604.6	658.4	579.9	672.9	732.8	684.7	68.3	11.3%	74.4	11.3%	104.8	18.1%
PPL	EE	49.8	54.2	34.0	66.8	72.6	67.6	17.0	34.1%	18.4	33.9%	33.6	99.1%
DAY	DR	189.2	205.8	164.5	215.9	235.0	227.7	26.7	14.1%	29.2	14.2%	63.2	38.4%
DAY	EE	43.7	47.4	32.9	62.0	67.2	59.5	18.4	42.1%	19.9	41.9%	26.6	81.0%
DEOK	DR	157.0	170.3	145.7	196.8	214.0	201.8	39.8	25.3%	43.7	25.7%	56.1	38.5%
DEOK	EE	61.1	66.4	65.6	82.2	89.6	89.1	21.1	34.6%	23.2	35.0%	23.5	35.9%

Table 32 Impact of demand side products: 2021/2022 RPM Base Residual Auction Scenario 5

		Actual Auction Results		No Offers for DR or EE	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$140.00	162,911.8	$189.11	158,019.2
	Summer	$140.00	715.5	$189.11	106.2
	Winter	$140.00	715.5	$189.11	106.2
RTO Total			163,627.3		158,125.4
ATSI	Annual	$171.33	8,007.3	$216.83	7,595.6
	Summer	$171.33	6.3	$216.83	0.0
	Winter	$171.33	0.0	$216.83	0.0
ATSI Total			8,007.3		7,595.6
EMAAC	Annual	$165.73	29,287.5	$189.11	28,481.8
	Summer	$165.73	88.0	$189.11	5.7
	Winter	$165.73	1.0	$189.11	0.0
EMAAC Total			29,288.5		28,481.8
PSEG	Annual	$204.29	5,366.6	$207.08	4,983.6
	Summer	$204.29	9.3	$207.08	2.4
	Winter	$204.29	1.0	$207.08	0.0
PSEG Total			5,367.6		4,983.6
BGE	Annual	$200.30	1,937.7	$189.11	2,839.3
	Summer	$200.30	85.0	$189.11	0.0
	Winter	$200.30	0.0	$189.11	0.0
BGE Total			1,937.7		2,839.3
ComEd	Annual	$195.55	22,083.6	$189.11	21,719.1
	Summer	$195.55	274.5	$189.11	0.0
	Winter	$195.55	274.5	$189.11	96.8
ComEd Total			22,358.1		21,719.1

Table 33 Impact of EE resources: 2021/2022 RPM Base Residual Auction

Scenario 6

		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	$140.00	162,911.8	$127.28	159,410.3
	Summer	$140.00	715.5	$127.28	715.5
	Winter	$140.00	715.5	$127.28	715.5
RTO Total			163,627.3		160,125.8
ATSI	Annual	$171.33	8,007.3	$145.00	7,843.6
	Summer	$171.33	6.3	$145.00	0.0
	Winter	$171.33	0.0	$145.00	0.0
ATSI Total			8,007.3		7,843.6
EMAAC	Annual	$165.73	29,287.5	$165.00	28,360.8
	Summer	$165.73	88.0	$165.00	117.3
	Winter	$165.73	1.0	$165.00	1.0
EMAAC Total			29,288.5		28,361.8
PSEG	Annual	$204.29	5,366.6	$179.16	5,048.6
	Summer	$204.29	9.3	$179.16	1.0
	Winter	$204.29	1.0	$179.16	1.0
PSEG Total			5,367.6		5,049.6
BGE	Annual	$200.30	1,937.7	$191.18	1,834.1
	Summer	$200.30	85.0	$191.18	152.6
	Winter	$200.30	0.0	$191.18	0.0
BGE Total			1,937.7		1,834.1
ComEd	Annual	$195.55	22,083.6	$189.10	21,376.0
	Summer	$195.55	274.5	$189.10	172.2
	Winter	$195.55	274.5	$189.10	274.5
ComEd Total			22,358.1		21,548.2
DEOK	Annual	$140.00	2,733.3	$128.47	2,512.9
	Summer	$140.00	25.4	$128.47	43.6
	Winter	$140.00	0.0	$128.47	0.0
DEOK Total			2,733.3		2,512.9

Table 34 Impact of annual demand side products: 2021/2022 RPM Base Residual Auction

Scenario 7

		Actual Auction Results		No Offers for Annual DR and Annual EE	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$140.00	162,911.8	$189.10	157,682.7
	Summer	$140.00	715.5	$189.10	715.5
	Winter	$140.00	715.5	$189.10	715.5
RTO Total			163,627.3		158,398.2
ATSI	Annual	$171.33	8,007.3	$216.83	7,614.6
	Summer	$171.33	6.3	$216.83	6.3
	Winter	$171.33	0.0	$216.83	0.0
ATSI Total			8,007.3		7,614.6
EMAAC	Annual	$165.73	29,287.5	$189.10	28,482.7
	Summer	$165.73	88.0	$189.10	86.9
	Winter	$165.73	1.0	$189.10	1.0
EMAAC Total			29,288.5		28,483.7
PSEG	Annual	$204.29	5,366.6	$207.08	4,984.5
	Summer	$204.29	9.3	$207.08	7.8
	Winter	$204.29	1.0	$207.08	1.0
PSEG Total			5,367.6		4,985.5
BGE	Annual	$200.30	1,937.7	$189.10	2,839.3
	Summer	$200.30	85.0	$189.10	85.3
	Winter	$200.30	0.0	$189.10	0.0
BGE Total			1,937.7		2,839.3
ComEd	Annual	$195.55	22,083.6	$189.10	21,362.7
	Summer	$195.55	274.5	$189.10	274.5
	Winter	$195.55	274.5	$189.10	274.5
ComEd Total			22,358.1		21,637.2

Table 35 Impact of seasonal demand side products: 2021/2022 RPM Base Residual Auction

Scenario 8

		Actual Auction Results		No Offers for Seasonal DR and Seasonal EE	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$140.00	162,911.8	$140.00	163,116.3
	Summer	$140.00	715.5	$140.00	106.2
	Winter	$140.00	715.5	$140.00	106.2
RTO Total			163,627.3		163,222.5
ATSI	Annual	$171.33	8,007.3	$166.26	8,005.8
	Summer	$171.33	6.3	$166.26	0.0
	Winter	$171.33	0.0	$166.26	0.0
ATSI Total			8,007.3		8,005.8
EMAAC	Annual	$165.73	29,287.5	$165.47	29,228.8
	Summer	$165.73	88.0	$165.47	5.7
	Winter	$165.73	1.0	$165.47	0.5
EMAAC Total			29,288.5		29,229.3
PSEG	Annual	$204.29	5,366.6	$198.45	5,355.5
	Summer	$204.29	9.3	$198.45	2.4
	Winter	$204.29	1.0	$198.45	0.5
PSEG Total			5,367.6		5,356.0
BGE	Annual	$200.30	1,937.7	$198.69	1,937.7
	Summer	$200.30	85.0	$198.69	0.0
	Winter	$200.30	0.0	$198.69	0.0
BGE Total			1,937.7		1,937.7
ComEd	Annual	$195.55	22,083.6	$190.79	22,255.9
	Summer	$195.55	274.5	$190.79	0.0
	Winter	$195.55	274.5	$190.79	94.9
ComEd Total			22,358.1		22,255.9

Table 36 Impact of seasonal products: 2021/2022 RPM Base Residual Auction Scenario 9

		Actual Auction Results		Annual Only	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$140.00	162,911.8	$142.49	163,142.0
	Summer	$140.00	715.5	$142.49	0.0
	Winter	$140.00	715.5	$142.49	0.0
RTO Total			163,627.3		163,142.0
ATSI	Annual	$171.33	8,007.3	$166.26	8,005.8
	Summer	$171.33	6.3	$166.26	0.0
	Winter	$171.33	0.0	$166.26	0.0
ATSI Total			8,007.3		8,005.8
EMAAC	Annual	$165.73	29,287.5	$165.47	29,229.3
	Summer	$165.73	88.0	$165.47	0.0
	Winter	$165.73	1.0	$165.47	0.0
EMAAC Total			29,288.5		29,229.3
PSEG	Annual	$204.29	5,366.6	$198.66	5,355.5
	Summer	$204.29	9.3	$198.66	0.0
	Winter	$204.29	1.0	$198.66	0.0
PSEG Total			5,367.6		5,355.5
BGE	Annual	$200.30	1,937.7	$198.69	1,937.7
	Summer	$200.30	85.0	$198.69	0.0
	Winter	$200.30	0.0	$198.69	0.0
BGE Total			1,937.7		1,937.7
ComEd	Annual	$195.55	22,083.6	$190.79	22,255.9
	Summer	$195.55	274.5	$190.79	0.0
	Winter	$195.55	274.5	$190.79	0.0
ComEd Total			22,358.1		22,255.9

Table 37 Impact of demand side and seasonal products: 2021/2022 RPM Base Residual Auction

Scenario 10

		Actual Auction Results		Annual Generation Offers Only	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$140.00	162,911.8	$189.12	158,125.1
	Summer	$140.00	715.5	$189.12	0.0
	Winter	$140.00	715.5	$189.12	0.0
RTO Total			163,627.3		158,125.1
ATSI	Annual	$171.33	8,007.3	$216.83	7,595.6
	Summer	$171.33	6.3	$216.83	0.0
	Winter	$171.33	0.0	$216.83	0.0
ATSI Total			8,007.3		7,595.6
EMAAC	Annual	$165.73	29,287.5	$189.12	28,481.8
	Summer	$165.73	88.0	$189.12	0.0
	Winter	$165.73	1.0	$189.12	0.0
EMAAC Total			29,288.5		28,481.8
PSEG	Annual	$204.29	5,366.6	$207.08	4,983.6
	Summer	$204.29	9.3	$207.08	0.0
	Winter	$204.29	1.0	$207.08	0.0
PSEG Total			5,367.6		4,983.6
BGE	Annual	$200.30	1,937.7	$189.12	2,839.3
	Summer	$200.30	85.0	$189.12	0.0
	Winter	$200.30	0.0	$189.12	0.0
BGE Total			1,937.7		2,839.3
ComEd	Annual	$195.55	22,083.6	$189.12	21,825.0
	Summer	$195.55	274.5	$189.12	0.0
	Winter	$195.55	274.5	$189.12	0.0
ComEd Total			22,358.1		21,825.0

Table 38 Impact of winter resources: 2021/2022 RPM Base Residual Auction

Scenario 11

		Actual Auction Results		Reduce Winter Offers by 50 Percent	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$140.00	162,911.8	$141.31	163,226.0
	Summer	$140.00	715.5	$141.31	358.9
	Winter	$140.00	715.5	$141.31	358.9
RTO Total			163,627.3		163,584.9
ATSI	Annual	$171.33	8,007.3	$171.33	8,007.3
	Summer	$171.33	6.3	$171.33	3.0
	Winter	$171.33	0.0	$171.33	0.0
ATSI Total			8,007.3		8,007.3
EMAAC	Annual	$165.73	29,287.5	$165.73	29,288.0
	Summer	$165.73	88.0	$165.73	39.9
	Winter	$165.73	1.0	$165.73	0.5
EMAAC Total			29,288.5		29,288.5
PSEG	Annual	$204.29	5,366.6	$204.50	5,366.6
	Summer	$204.29	9.3	$204.50	1.8
	Winter	$204.29	1.0	$204.50	0.5
PSEG Total			5,367.6		5,367.1
BGE	Annual	$200.30	1,937.7	$200.30	1,937.7
	Summer	$200.30	85.0	$200.30	41.1
	Winter	$200.30	0.0	$200.30	0.0
BGE Total			1,937.7		1,937.7
ComEd	Annual	$195.55	22,083.6	$184.04	22,279.7
	Summer	$195.55	274.5	$184.04	137.7
	Winter	$195.55	274.5	$184.04	137.7
ComEd Total			22,358.1		22,417.4

Table 39 Impact of seasonal matching across LDAs: 2021/2022 RPM Base Residual Auction

Scenario 12

		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	$140.00	162,911.8	$140.00	162,911.8
	Summer	$140.00	715.5	$140.00	715.5
	Winter	$140.00	715.5	$140.00	715.5
RTO Total			163,627.3		163,627.3
ATSI	Annual	$171.33	8,007.3	$171.33	8,007.3
	Summer	$171.33	6.3	$171.33	6.3
	Winter	$171.33	0.0	$171.33	0.0
ATSI Total			8,007.3		8,007.3
EMAAC	Annual	$165.73	29,287.5	$165.73	29,287.5
	Summer	$165.73	88.0	$165.73	88.0
	Winter	$165.73	1.0	$165.73	1.0
EMAAC Total			29,288.5		29,288.5
PSEG	Annual	$204.29	5,366.6	$204.29	5,366.6
	Summer	$204.29	9.3	$204.29	9.3
	Winter	$204.29	1.0	$204.29	1.0
PSEG Total			5,367.6		5,367.6
BGE	Annual	$200.30	1,937.7	$200.30	1,937.7
	Summer	$200.30	85.0	$200.30	85.0
	Winter	$200.30	0.0	$200.30	0.0
BGE Total			1,937.7		1,937.7
ComEd	Annual	$195.55	22,083.6	$195.55	22,083.6
	Summer	$195.55	274.5	$195.55	274.5
	Winter	$195.55	274.5	$195.55	274.5
ComEd Total			22,358.1		22,358.1

Table 40 RPM imports: 2007/2008 through 2021/2022 RPM Base Residual Auctions

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

Table 41 Impact of capacity imports: 2021/2022 RPM Base Residual Auction

Scenario 13, Scenario 14, Scenario 15, Scenario 16

		Actual Auction Results		Reduce Imports 25 percent		Reduce Imports 50 percent		Reduce Imports 75 percent		Reduce Imports 100 percent	
LDA	Product Type	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)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$140.00	162,911.8	$149.47	162,605.3	$160.80	162,238.8	$170.00	161,941.1	$172.64	161,855.6
	Summer	$140.00	715.5	$149.47	715.5	$160.80	715.5	$170.00	715.5	$172.64	715.5
	Winter	$140.00	715.5	$149.47	715.5	$160.80	715.5	$170.00	715.5	$172.64	715.5
RTO Total			163,627.3		163,320.8		162,954.3		162,656.6		162,571.1
ATSI	Annual	$171.33	8,007.3	$171.33	8,007.3	$171.33	8,007.3	$171.33	8,007.3	$172.64	8,007.3
	Summer	$171.33	6.3	$171.33	6.3	$171.33	6.3	$171.33	6.4	$172.64	6.3
	Winter	$171.33	0.0	$171.33	0.0	$171.33	0.0	$171.33	0.0	$172.64	0.0
ATSI Total			8,007.3		8,007.3		8,007.3		8,007.3		8,007.3
EMAAC	Annual	$165.73	29,287.5	$165.73	29,287.5	$165.73	29,287.5	$170.00	29,317.8	$172.64	29,393.5
	Summer	$165.73	88.0	$165.73	87.9	$165.73	87.9	$170.00	83.6	$172.64	87.9
	Winter	$165.73	1.0	$165.73	1.0	$165.73	1.0	$170.00	1.0	$172.64	1.0
EMAAC Total			29,288.5		29,288.5		29,288.5		29,318.8		29,394.5
PSEG	Annual	$204.29	5,366.6	$204.29	5,366.6	$204.29	5,366.6	$204.29	5,366.6	$204.29	5,366.6
	Summer	$204.29	9.3	$204.29	9.3	$204.29	9.3	$204.29	3.6	$204.29	9.3
	Winter	$204.29	1.0	$204.29	1.0	$204.29	1.0	$204.29	1.0	$204.29	1.0
PSEG Total			5,367.6		5,367.6		5,367.6		5,367.6		5,367.6
BGE	Annual	$200.30	1,937.7	$200.30	1,937.7	$200.30	1,937.7	$200.30	1,937.7	$200.30	1,937.7
	Summer	$200.30	85.0	$200.30	84.6	$200.30	84.6	$200.30	86.1	$200.30	84.6
	Winter	$200.30	0.0	$200.30	0.0	$200.30	0.0	$200.30	0.0	$200.30	0.0
BGE Total			1,937.7		1,937.7		1,937.7		1,937.7		1,937.7
ComEd	Annual	$195.55	22,083.6	$189.01	22,117.3	$189.01	22,117.3	$189.01	22,117.3	$184.05	22,142.8
	Summer	$195.55	274.5	$189.01	274.5	$189.01	274.5	$189.01	274.5	$184.05	274.5
	Winter	$195.55	274.5	$189.01	274.5	$189.01	274.5	$189.01	274.5	$184.05	274.5
ComEd Total			22,358.1		22,391.8		22,391.8		22,391.8		22,417.3

Table 42 Impact of demand side and seasonal products, and capacity imports: 2021/2022 RPM Base Residual Auction

Scenario 17

		Actual Auction Results		Annual Generation Only, No DR and Reduce Imports 100 pct	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$140.00	162,911.8	$208.16	157,509.1
	Summer	$140.00	715.5	$208.16	0.0
	Winter	$140.00	715.5	$208.16	0.0
RTO Total			163,627.3		157,509.1
ATSI	Annual	$171.33	8,007.3	$216.83	7,595.6
	Summer	$171.33	6.3	$216.83	0.0
	Winter	$171.33	0.0	$216.83	0.0
ATSI Total			8,007.3		7,595.6
EMAAC	Annual	$165.73	29,287.5	$208.16	29,638.6
	Summer	$165.73	88.0	$208.16	0.0
	Winter	$165.73	1.0	$208.16	0.0
EMAAC Total			29,288.5		29,638.6
PSEG	Annual	$204.29	5,366.6	$208.16	5,127.4
	Summer	$204.29	9.3	$208.16	0.0
	Winter	$204.29	1.0	$208.16	0.0
PSEG Total			5,367.6		5,127.4
BGE	Annual	$200.30	1,937.7	$208.16	2,839.3
	Summer	$200.30	85.0	$208.16	0.0
	Winter	$200.30	0.0	$208.16	0.0
BGE Total			1,937.7		2,839.3
ComEd	Annual	$195.55	22,083.6	$208.16	22,707.1
	Summer	$195.55	274.5	$208.16	0.0
	Winter	$195.55	274.5	$208.16	0.0
ComEd Total			22,358.1		22,707.1

Table 43 Impact of inconsistency between EE cleared MW and EE add back MW: 2021/2022 RPM Base Residual Auction

Scenario 18

		Actual Auction Results		EE Add Back Equal to Cleared EE	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$140.00	162,911.8	$132.68	162,087.9
	Summer	$140.00	715.5	$132.68	715.5
	Winter	$140.00	715.5	$132.68	715.5
RTO Total			163,627.3		162,803.4
ATSI	Annual	$171.33	8,007.3	$145.00	7,985.5
	Summer	$171.33	6.3	$145.00	11.4
	Winter	$171.33	0.0	$145.00	0.0
ATSI Total			8,007.3		7,985.5
EMAAC	Annual	$165.73	29,287.5	$165.00	28,944.5
	Summer	$165.73	88.0	$165.00	22.6
	Winter	$165.73	1.0	$165.00	1.0
EMAAC Total			29,288.5		28,945.5
PSEG	Annual	$204.29	5,366.6	$179.58	5,268.3
	Summer	$204.29	9.3	$179.58	6.7
	Winter	$204.29	1.0	$179.58	1.0
PSEG Total			5,367.6		5,269.3
BGE	Annual	$200.30	1,937.7	$191.18	1,937.7
	Summer	$200.30	85.0	$191.18	153.1
	Winter	$200.30	0.0	$191.18	0.0
BGE Total			1,937.7		1,937.7
ComEd	Annual	$195.55	22,083.6	$189.10	22,038.0
	Summer	$195.55	274.5	$189.10	274.5
	Winter	$195.55	274.5	$189.10	274.5
ComEd Total			22,358.1		22,312.5

Table 44 Impact of price responsive demand (PRD): 2021/2022 RPM Base Residual Auction

Scenario 19

		Actual Auction Results		No PRD Offers	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$140.00	162,911.8	$142.60	163,383.5
	Summer	$140.00	715.5	$142.60	715.5
	Winter	$140.00	715.5	$142.60	715.5
RTO Total			163,627.3		164,099.0
ATSI	Annual	$171.33	8,007.3	$171.33	8,007.3
	Summer	$171.33	6.3	$171.33	5.4
	Winter	$171.33	0.0	$171.33	0.0
ATSI Total			8,007.3		8,007.3
EMAAC	Annual	$165.73	29,287.5	$172.33	29,317.8
	Summer	$165.73	88.0	$172.33	10.4
	Winter	$165.73	1.0	$172.33	1.0
EMAAC Total			29,288.5		29,318.8
PSEG	Annual	$204.29	5,366.6	$204.29	5,366.6
	Summer	$204.29	9.3	$204.29	3.2
	Winter	$204.29	1.0	$204.29	1.0
PSEG Total			5,367.6		5,367.6
BGE	Annual	$200.30	1,937.7	$180.50	2,221.2
	Summer	$200.30	85.0	$180.50	152.6
	Winter	$200.30	0.0	$180.50	0.0
BGE Total			1,937.7		2,221.2
ComEd	Annual	$195.55	22,083.6	$189.01	22,117.3
	Summer	$195.55	274.5	$189.01	274.5
	Winter	$195.55	274.5	$189.01	274.5
ComEd Total			22,358.1		22,391.8

Table 45 Peak load forecast history[147] [148]

	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		16.5%	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	152,407.9		(3.3%)	(4.5%)	(5.6%)	
Installed Reverve Margin		15.7%	16.50%	16.70%	16.1%		5.1%	6.4%	2.5%	
Pool Wide EFORd		6.35%	6.58%	6.59%	6.07%		3.6%	3.8%	(4.4%)	
Forecast Pool Requirement		1.0835	1.0883	1.0901	1.0905		0.4%	0.6%	0.6%	
Reliability Requirement		174,896.8	169,928.4	168,071.5	166,200.8		(2.8%)	(3.9%)	(5.0%)	
Forecast Peak Load	2017/2018	164,478.8	160,092.2	154,377.3	153,230.1	145,635.9	(2.7%)	(6.1%)	(6.8%)	(11.5%)
Installed Reverve Margin		15.7%	15.70%	16.50%	16.60%		0.0%	5.1%	5.7%	
Pool Wide EFORd		5.65%	5.70%	5.93%	5.94%		0.9%	5.0%	5.1%	
Forecast Pool Requirement		1.0916	1.0911	1.0959	1.0967		(0.0%)	0.4%	0.5%	
Reliability Requirement		179,545.1	174,676.6	169,182.1	168,047.5		(2.7%)	(5.8%)	(6.4%)	
Forecast Peak Load	2016/2017	165,412.0	162,749.7	158,193.0	152,356.6	152,176.9	(1.6%)	(4.4%)	(7.9%)	(8.0%)
Installed Reverve Margin		15.6%	15.70%	15.50%	16.40%		0.6%	(0.6%)	5.1%	
Pool Wide EFORd		5.69%	5.64%	5.66%	5.91%		(0.9%)	(0.5%)	3.9%	
Forecast Pool Requirement		1.0902	1.0917	1.0896	1.0952		0.1%	(0.1%)	0.5%	
Reliability Requirement		180,332.2	177,673.8	172,367.1	166,860.9		(1.5%)	(4.4%)	(7.5%)	
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		15.4%	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		15.3%	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		15.3%	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%)	

147 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, Third IA), 2018/2019 (First IA, Second IA, Third IA), 2019/2020 (BRA, First IA), 2020/2021 BRA, 2021/2022 BRA.

148 The data have 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 the 2013/2014, 2014/2015, and 2015/2016 Delivery Years are affected.

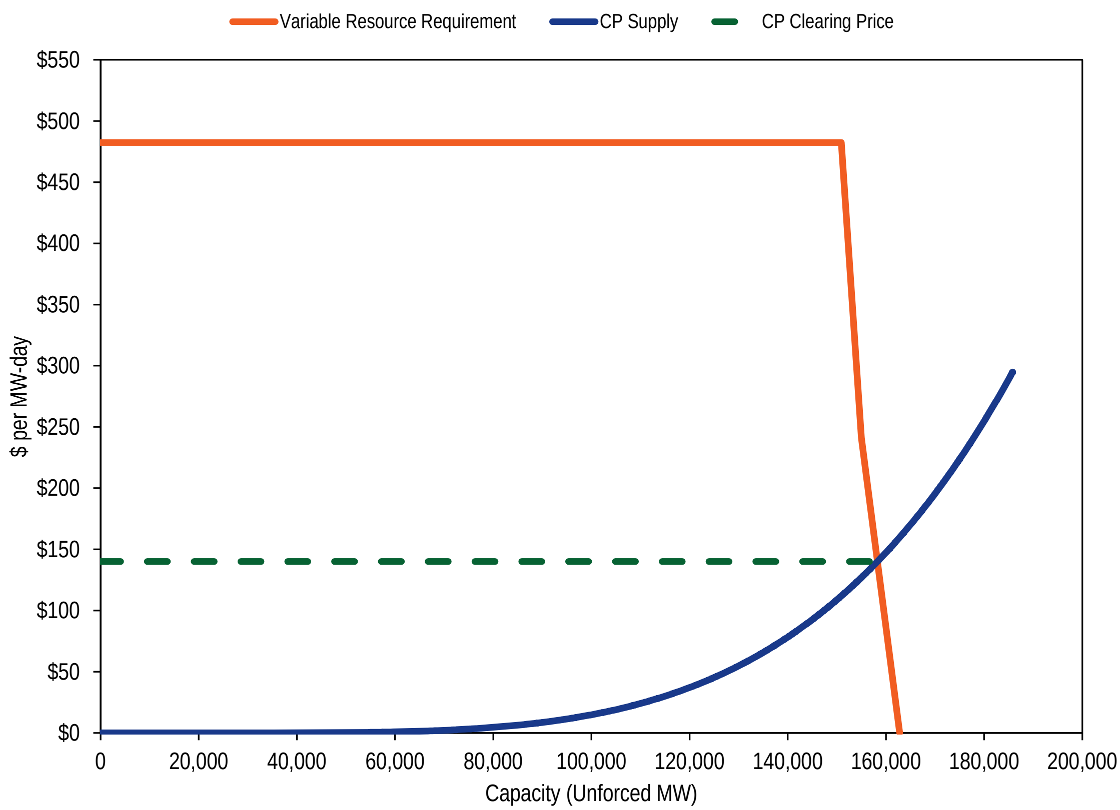
Table 46 Nuclear offers set to $0 per MW-day: 2021/2022 RPM Base Residual Auction Scenario 20

		Actual Auction Results		All Nuclear Offers at $0 per MW-day	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$140.00	162,911.8	$71.48	165,256.7
	Summer	$140.00	715.5	$71.48	587.6
	Winter	$140.00	715.5	$71.48	587.6
RTO Total			163,627.3		165,844.3
ATSI	Annual	$171.33	8,007.3	$71.48	8,603.4
	Summer	$171.33	6.3	$71.48	6.2
	Winter	$171.33	0.0	$71.48	0.0
ATSI Total			8,007.3		8,603.4
EMAAC	Annual	$165.73	29,287.5	$125.94	29,597.6
	Summer	$165.73	88.0	$125.94	86.7
	Winter	$165.73	1.0	$125.94	1.0
EMAAC Total			29,288.5		29,598.6
PSEG	Annual	$204.29	5,366.6	$204.29	5,366.6
	Summer	$204.29	9.3	$204.29	9.2
	Winter	$204.29	1.0	$204.29	1.0
PSEG Total			5,367.6		5,367.6
BGE	Annual	$200.30	1,937.7	$200.30	1,937.7
	Summer	$200.30	85.0	$200.30	83.5
	Winter	$200.30	0.0	$200.30	0.0
BGE Total			1,937.7		1,937.7
ComEd	Annual	$195.55	22,083.6	$71.48	24,345.0
	Summer	$195.55	274.5	$71.48	154.4
	Winter	$195.55	274.5	$71.48	268.2
ComEd Total			22,358.1		24,499.4
DEOK	Annual	$140.00	2,733.3	$128.47	2,636.3
	Summer	$140.00	25.4	$128.47	24.9
	Winter	$140.00	0.0	$128.47	0.0
DEOK Total			2,733.3		2,636.3

Table 47 Impact of noncompetitive offers: 2021/2022 RPM Base Residual Auction Scenario 21

		Actual Auction Results		Noncompetitive Offers capped at net ACR	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$140.00	162,911.8	$124.40	163,416.6
	Summer	$140.00	715.5	$124.40	715.5
	Winter	$140.00	715.5	$124.40	715.5
RTO Total			163,627.3		164,132.1
ATSI	Annual	$171.33	8,007.3	$169.65	8,013.1
	Summer	$171.33	6.3	$169.65	6.3
	Winter	$171.33	0.0	$169.65	0.0
ATSI Total			8,007.3		8,013.1
EMAAC	Annual	$165.73	29,287.5	$155.93	29,363.9
	Summer	$165.73	88.0	$155.93	87.9
	Winter	$165.73	1.0	$155.93	1.0
EMAAC Total			29,288.5		29,364.9
PSEG	Annual	$204.29	5,366.6	$204.29	5,366.6
	Summer	$204.29	9.3	$204.29	9.3
	Winter	$204.29	1.0	$204.29	1.0
PSEG Total			5,367.6		5,367.6
BGE	Annual	$200.30	1,937.7	$124.40	2,492.0
	Summer	$200.30	85.0	$124.40	84.6
	Winter	$200.30	0.0	$124.40	0.0
BGE Total			1,937.7		2,492.0
ComEd	Annual	$195.55	22,083.6	$130.04	22,421.0
	Summer	$195.55	274.5	$130.04	274.5
	Winter	$195.55	274.5	$130.04	274.5
ComEd Total			22,358.1		22,695.5
DEOK	Annual	$140.00	2,733.3	$128.47	2,636.3
	Summer	$140.00	25.4	$128.47	25.2
	Winter	$140.00	0.0	$128.47	0.0
DEOK Total			2,733.3		2,636.3

Figure 1 RTO market supply/demand curves: 2021/2022 RPM Base Residual Auction[149] [150]



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[149] 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.

[150] The VRR curve excludes incremental demand which cleared in EMAAC, PSEG, ATSI, ComEd, and BGE.

EMAAC LDA Market Results

Table 48 shows total EMAAC LDA offer data for the 2021/2022 RPM Base Residual Auction. Total internal EMAAC LDA unforced capacity, excluding generation winter capacity, of 33,795.6 MW includes all Generation Capacity Resources, Demand Resources, and Energy Efficiency Resources that qualified as PJM Capacity Resources, excludes external units, and also includes owners' modifications to ICAP ratings. As shown in Table 14, EMAAC LDA unforced internal capacity increased 622.2 MW from 33,173.4 MW in the 2020/2021 BRA as a result of net generation capacity modifications (79.5 MW), net DR modifications (35.6 MW), and net EE modifications (279.2 MW), the EFORd effect due to lower sell offer EFORds (226.8 MW), and the DR and EE effect due to a higher Load Management UCAP conversion factor (1.1 MW). As shown in Table 16, total internal EMAAC unforced winter capacity increased by 0.0 MW for November through April of the 2021/2022 Delivery Year.

All imports offered in the auction from areas external to PJM are modeled as supply in the rest of RTO.[151] Total internal EMAAC LDA capacity was reduced by FRR commitments of 0.0 MW, resulting in EMAAC LDA RPM capacity of 33,795.6 MW. RPM capacity was reduced by 670.3 MW of exports, 0.0 MW of FRR optional volumes not offered, 148.6 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 539.5 MW of intermittent resources and 322.8 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 (148.6 MW). Subtracting 162.9 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 31,951.5 MW.[152] 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 2021/2022 BRA. Of the 29,288.5 MW cleared in EMAAC LDA, 27,426.6 MW were cleared in the RTO before EMAAC LDA became constrained. Once the constraint was binding, based on the 9,000.0 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, 1,861.9 MW cleared, which resulted in a clearing price for Capacity Performance

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

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

Resources of $165.73 per MW-day, as shown in Figure 2. The clearing price was determined by the intersection of the incremental supply and VRR curve.

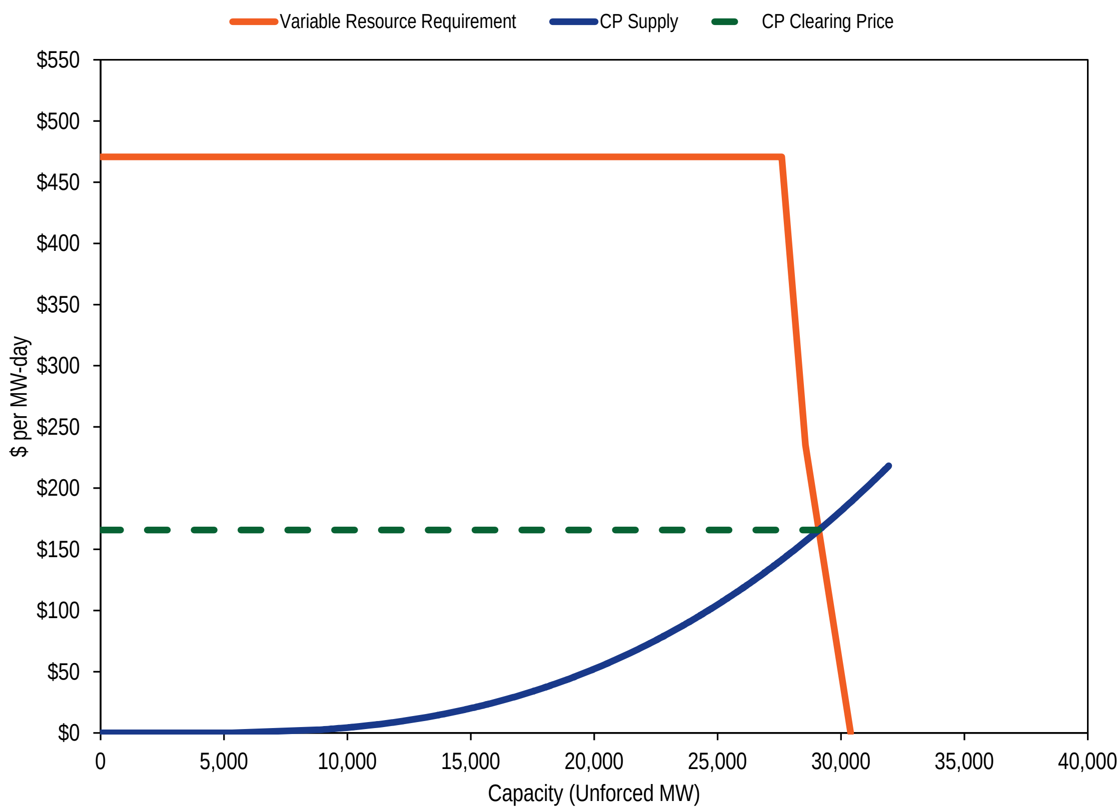
As shown in Table 11, the 28,671.5 MW of cleared and make whole generation and DR for EMAAC LDA and 9,000.0 MW CETL resulted in a net excess of 1,759.2 MW.

Table and Figure for EMAAC LDA

Table 48 EMAAC LDA offer statistics: 2021/2022 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	32,739.9	31,615.9		
DR capacity	1,403.6	1,529.8		
EE capacity	596.0	649.9		
Generation winter capacity	0.0	0.0		
Total internal EMAAC LDA capacity	34,739.5	33,795.6		
FRR	0.0	0.0		
Imports	0.0	0.0		
RPM capacity	34,739.5	33,795.6		
Exports	(674.0)	(670.3)		
FRR optional	0.0	0.0		
Excused Existing Generation Capacity Resources	(165.2)	(148.6)		
Unoffered Planned Generation Capacity Resources	0.0	0.0		
Unoffered Intermittent Resources	(545.7)	(539.5)		
Unoffered Capacity Storage Resources	(324.4)	(322.8)		
Unoffered generation winter capacity	0.0	0.0		
Unoffered DR and EE	(147.0)	(162.9)		
Available	32,883.2	31,951.5	100.0%	100.0%
Generation offered	31,030.6	29,934.7	94.4%	93.7%
DR offered	1,276.1	1,389.6	3.9%	4.3%
EE offered	576.5	627.2	1.8%	2.0%
Total offered	32,883.2	31,951.5	100.0%	100.0%
Unoffered Existing Generation Capacity Resources	0.0	0.0	0.0%	0.0%

Figure 2 EMAAC LDA market supply/demand curves: 2021/2022 RPM Base Residual Auction[153]



PSEG LDA Market Results

Table 49 shows total PSEG LDA offer data for the 2021/2022 RPM Base Residual Auction. Total internal PSEG LDA unforced capacity, excluding generation winter capacity, of 6,182.7 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 14, PSEG LDA unforced internal capacity increased 246.4 MW from 5,936.3 MW in the 2020/2021 BRA as a result of net generation capacity modifications (34.7 MW), net DR modifications (35.4 MW), and net EE modifications (141.8 MW), the EFORd effect due to lower sell offer EFORds (34.2 MW), and the DR and EE effect due to a higher Load Management UCAP conversion factor (0.3 MW). As shown in Table 16, total internal PSEG unforced winter capacity increased by 0.0 MW for November through April of the 2021/2022 Delivery Year.

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153 The VRR curve is reduced by the CETL and incremental demand which cleared in PSEG.

All imports offered in the auction from areas external to PJM are modeled as supply in the rest of RTO.[154] Total internal PSEG LDA capacity was reduced by FRR commitments of 0.0 MW, resulting in PSEG LDA RPM capacity of 6,182.7 MW. RPM capacity was reduced by 0.0 MW of exports, 0.0 MW of FRR optional volumes not offered, 148.6 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 46.2 MW of intermittent resources and 0.0 MW of capacity storage resources which were not subject to the CP must offer requirement. The excused Existing Generation Capacity Resources were the result of plans for retirement (148.6 MW). Subtracting 19.3 MW of DR and EE not offered and 0.0 MW of unoffered generation winter capacity resulted in available unforced capacity in PSEG LDA of 5,968.6 MW.[155] After accounting for these exceptions, all capacity resources in PSEG were offered in the RPM Auction.

The PSEG LDA import limit was a binding constraint in the 2021/2022 BRA. Of the 5,367.6 MW cleared in PSEG LDA, 4,750.1 MW were cleared in the RTO and an additional 352.4 MW were cleared in EMAAC before PSEG LDA became constrained. Once the constraint was binding, based on the 6,902.0 MW CETL value, only the incremental supply located in PSEG LDA was available to meet the incremental demand in the LDA. Of the incremental supply, 265.1 MW cleared, which resulted in a clearing price for Capacity Performance Resources of $204.29 per MW-day, as shown in Figure 3. The clearing price was determined by the intersection of the incremental supply and VRR curve.

As shown in Table 11, the 5,127.5 MW of cleared and make whole generation and DR for PSEG LDA and 6,902.0 MW CETL resulted in a net excess of 528.5 MW.

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

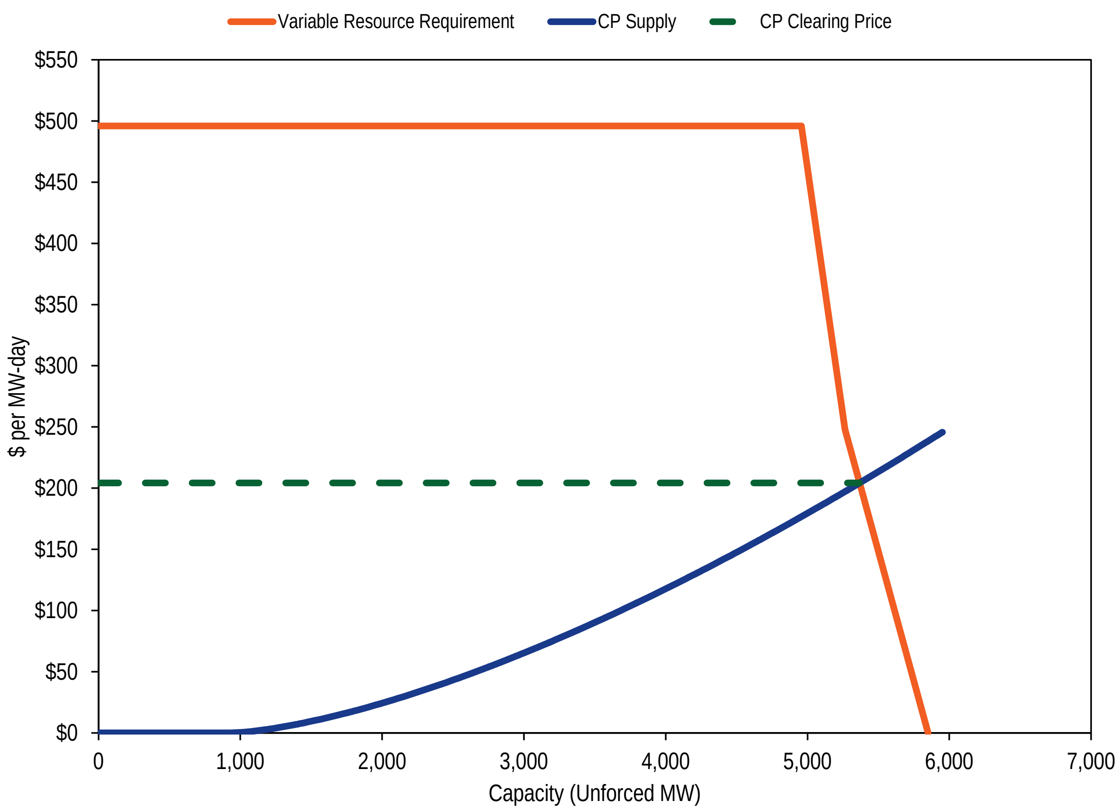
155 Unoffered DR and EE MW include PJM approved DR and EE plans that were not offered in the auction.

Table and Figure for PSEG LDA

Table 49 PSEG LDA offer statistics: 2021/2022 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	5,838.1	5,497.0		
DR capacity	390.9	426.1		
EE capacity	238.0	259.6		
Generation winter capacity	0.0	0.0		
Total internal PSEG LDA capacity	6,467.0	6,182.7		
FRR	0.0	0.0		
Imports	0.0	0.0		
RPM capacity	6,467.0	6,182.7		
Exports	0.0	0.0		
FRR optional	0.0	0.0		
Excused Existing Generation Capacity Resources	(165.2)	(148.6)		
Unoffered Planned Generation Capacity Resources	0.0	0.0		
Unoffered Intermittent Resources	(46.2)	(46.2)		
Unoffered Capacity Storage Resources	0.0	0.0		
Unoffered generation winter capacity	0.0	0.0		
Unoffered DR and EE	(17.2)	(19.3)		
Available	6,238.4	5,968.6	100.0%	100.0%
Generation offered	5,626.7	5,302.2	90.2%	88.8%
DR offered	381.7	415.9	6.1%	7.0%
EE offered	230.0	250.6	3.7%	4.2%
Total offered	6,238.4	5,968.6	100.0%	100.0%
Unoffered Existing Generation Capacity Resources	0.0	0.0	0.0%	0.0%

Figure 3 PSEG LDA market supply/demand curves: 2021/2022 RPM Base Residual Auction[156]



ATSI LDA Market Results

Table 50 shows total ATSI LDA offer data for the 2021/2022 RPM Base Residual Auction. Total internal ATSI LDA unforced capacity, excluding generation winter capacity, of 12,639.2 MW includes all Generation Capacity Resources, Demand Resources, and Energy Efficiency Resources that qualified as PJM Capacity Resources, excludes external units, and also includes owners' modifications to ICAP ratings. As shown in Table 14, ATSI LDA unforced internal capacity decreased 79.4 MW from 12,718.6 MW in the 2020/2021 BRA as a result of net generation capacity modifications (18.9 MW), net DR modifications (29.4 MW), and net EE modifications (107.0 MW), the EFORd effect due to higher sell offer EFORds (-235.7 MW), and the DR and EE effect due to a higher Load Management UCAP conversion factor (1.0 MW). As shown in Table 16, total internal ATSI unforced winter capacity increased by 0.0 MW for November through April of the 2021/2022 Delivery Year.

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156 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.[157] Total internal ATSI LDA capacity was reduced by FRR commitments of 0.0 MW, resulting in ATSI LDA RPM capacity of 12,639.2 MW. RPM capacity was reduced by 0.0 MW of exports, 0.0 MW of FRR optional volumes not offered, 554.4 MW excused from the RPM must offer requirement, 0.0 MW of Planned Generation Capacity Resources which were not subject to the RPM must offer requirement, and 0.0 MW of intermittent resources and 0.0 MW of capacity storage resources which were not subject to the CP must offer requirement. The excused Existing Generation Capacity Resources were the result of plans for retirement (551.9 MW) and the resource being reasonably expected to be physically incapable of satisfying the requirements of a Capacity Performance Resource (2.5 MW). Subtracting 52.4 MW of DR and EE not offered and 0.0 MW of unoffered generation winter capacity resulted in available unforced capacity in ATSI LDA of 12,032.4 MW.[158] After accounting for these exceptions, all capacity resources in ATSI were offered in the RPM Auction.

The ATSI LDA import limit was a binding constraint in the 2021/2022 BRA. Of the 8,007.3 MW cleared in ATSI LDA, 6,757.7 MW were cleared in the RTO before ATSI LDA became constrained. Once the constraint was binding, based on the 8,439.0 MW CETL value, only the incremental supply located in ATSI LDA was available to meet the incremental demand in the LDA. Of the incremental supply, 1,249.6 MW cleared, which resulted in a clearing price for Capacity Performance Resources of $171.33 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 11, the 7,859.1 MW of cleared and make whole generation and DR for ATSI LDA and 8,439.0 MW CETL resulted in a net excess of 700.1 MW.

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

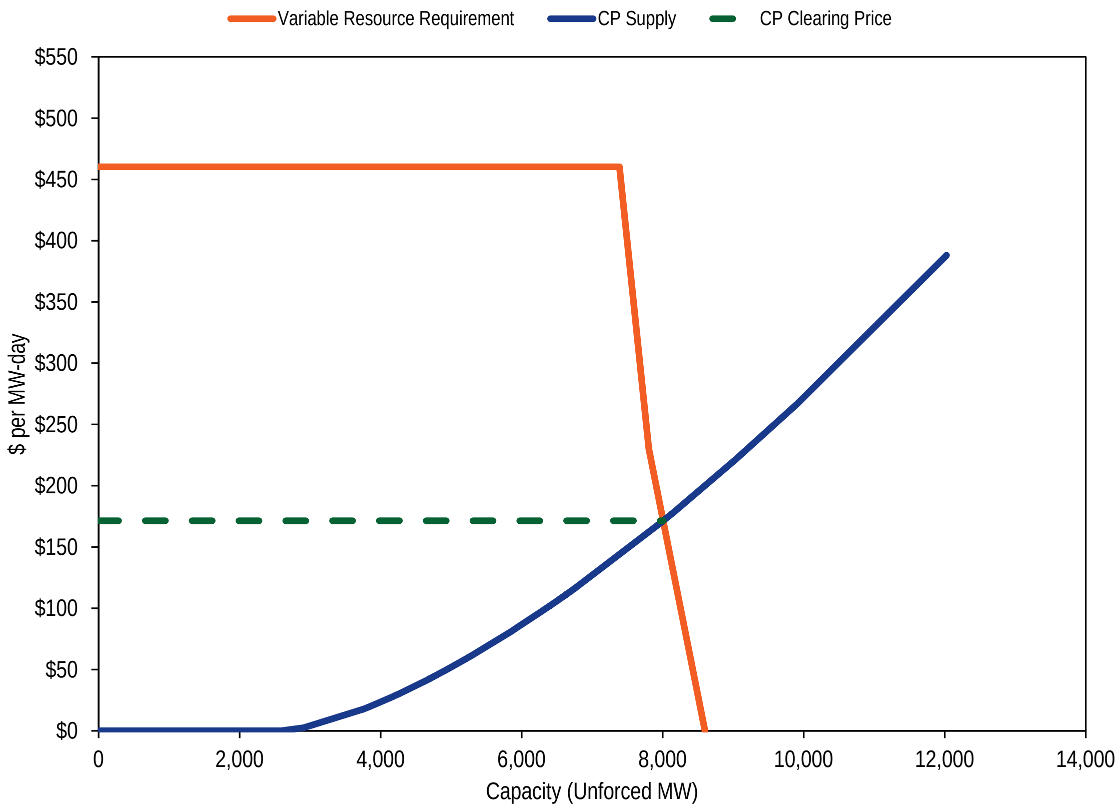
158 Unoffered DR and EE MW include PJM approved DR and EE plans that were not offered in the auction.

Table and Figure for ATSI LDA

Table 50 ATSI LDA offer statistics: 2021/2022 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	12,743.9	11,218.0		
DR capacity	1,150.2	1,253.4		
EE capacity	153.9	167.8		
Generation winter capacity	0.0	0.0		
Total internal ATSI LDA capacity	14,048.0	12,639.2		
FRR	0.0	0.0		
Imports	0.0	0.0		
RPM capacity	14,048.0	12,639.2		
Exports	0.0	0.0		
FRR optional	0.0	0.0		
Excused Existing Generation Capacity Resources	(778.5)	(554.4)		
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	(47.8)	(52.4)		
Available	13,221.7	12,032.4	100.0%	100.0%
Generation offered	11,965.4	10,663.6	90.5%	88.6%
DR offered	1,120.8	1,221.2	8.5%	10.1%
EE offered	135.5	147.6	1.0%	1.2%
Total offered	13,221.7	12,032.4	100.0%	100.0%
Unoffered Existing Generation Capacity Resources	0.0	0.0	0.0%	0.0%

Figure 4 ATSI LDA market supply/demand curves: 2021/2022 RPM Base Residual Auction[159]



ComEd LDA Market Results

Table 51 shows total ComEd LDA offer data for the 2021/2022 RPM Base Residual Auction. Total internal ComEd LDA unforced capacity, excluding generation winter capacity, of 28,585.9 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 14, ComEd LDA unforced internal capacity increased 335.1 MW from 28,250.8 MW in the 2020/2021 BRA as a result of net generation capacity modifications (157.8 MW), net DR modifications (87.8 MW), and net EE modifications (-30.7 MW), the EFORd effect due to lower sell offer EFORds (118.4 MW), and the DR and EE effect due to a higher Load Management UCAP conversion factor (1.8 MW). As shown in Table 16, total internal ComEd unforced winter capacity increased by 112.5 MW for November

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

through April of the 2021/2022 Delivery Year as a result of net generation winter capacity modifications (112.5 MW).

All imports offered in the auction from areas external to PJM are modeled as supply in the rest of RTO.[160] Total internal ComEd LDA capacity was reduced by FRR commitments of 14.7 MW, resulting in ComEd LDA RPM capacity of 28,750.3 MW. RPM capacity was reduced by 541.2 MW of exports, 0.0 MW of FRR optional volumes not offered, 141.5 MW excused from the RPM must offer requirement, 0.0 MW of Planned Generation Capacity Resources which were not subject to the RPM must offer requirement, and 187.0 MW of intermittent resources and 0.0 MW of capacity storage resources which were not subject to the CP must offer requirement. The excused Existing Generation Capacity Resources were the result of the resource being considered existing for purposes of the RPM must offer requirement and mitigation only because it cleared an RPM Auction in a prior delivery year but is unable to achieve full commercial operation prior to the delivery year (141.5 MW). Subtracting 158.6 MW of DR and EE not offered and 74.1 MW of unoffered generation winter capacity resulted in available unforced capacity in ComEd LDA of 27,648.0 MW.[161] 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 2021/2022 BRA. Of the 22,358.1 MW cleared in ComEd LDA, 20,624.6 MW were cleared in the RTO before ComEd LDA became constrained. Once the constraint was binding, based on the 5,574.0 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, 1,733.5 MW cleared, which resulted in a clearing price for Capacity Performance Resources of $195.55 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 11, the 21,587.6 MW of cleared and make whole generation and DR for ComEd LDA and 5,574.0 MW CETL resulted in a net excess of 1,049.6 MW.

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

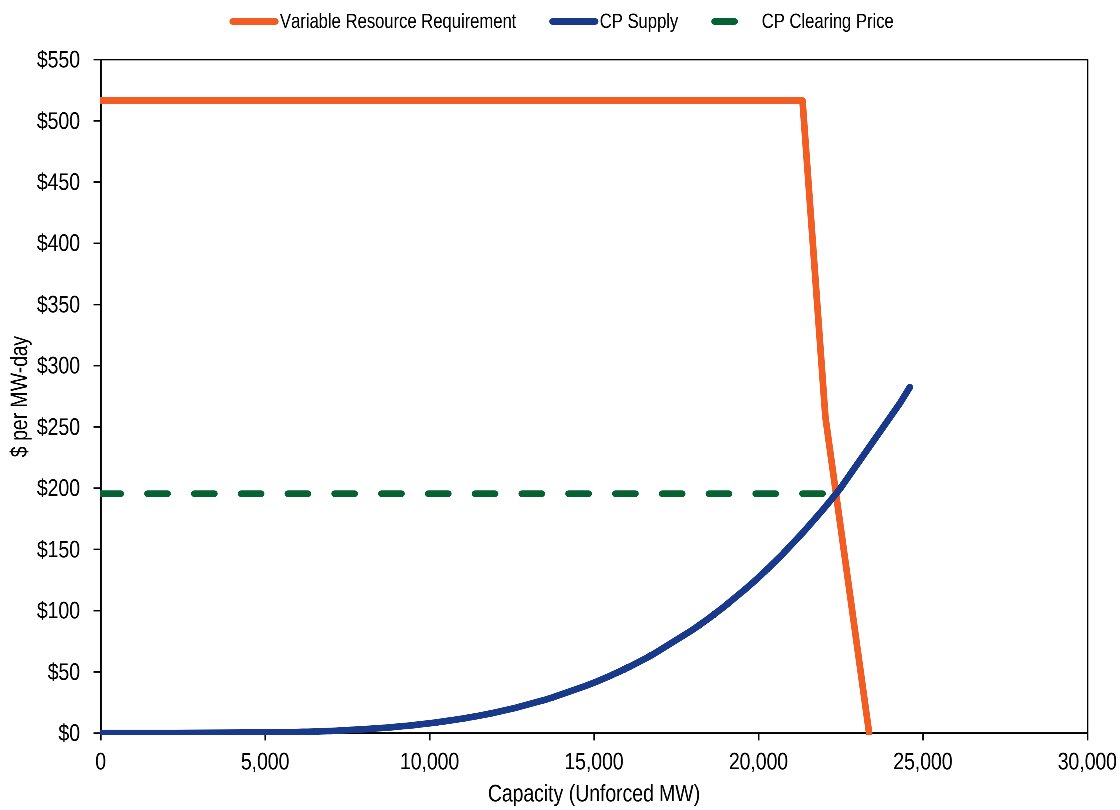
161 Unoffered DR and EE MW include PJM approved DR and EE plans that were not offered in the auction.

Table and Figure for ComEd LDA

Table 51 ComEd LDA offer statistics: 2021/2022 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	26,225.4	25,705.6		
DR capacity	1,920.1	2,092.7		
EE capacity	722.8	787.6		
Generation winter capacity	179.1	179.1		
Total internal ComEd LDA capacity	29,047.4	28,765.0		
FRR	(14.7)	(14.7)		
Imports	0.0	0.0		
RPM capacity	29,032.7	28,750.3		
Exports	(544.4)	(541.2)		
FRR optional	0.0	0.0		
Excused Existing Generation Capacity Resources	(157.0)	(141.5)		
Unoffered Planned Generation Capacity Resources	0.0	0.0		
Unoffered Intermittent Resources	(187.0)	(187.0)		
Unoffered Capacity Storage Resources	0.0	0.0		
Unoffered generation winter capacity	(74.1)	(74.1)		
Unoffered DR and EE	(145.2)	(158.6)		
Available	27,925.0	27,648.0	100.0%	100.0%
Generation offered	25,427.3	24,926.2	91.1%	90.2%
DR offered	1,828.7	1,992.8	6.5%	7.2%
EE offered	668.9	728.9	2.4%	2.6%
Total offered	27,925.0	27,648.0	100.0%	100.0%
Unoffered Existing Generation Capacity Resources	0.0	0.0	0.0%	0.0%

Figure 5 ComEd LDA market supply/demand curves: 2021/2022 RPM Base Residual Auction[162]



BGE LDA Market Results

Table 52 shows total BGE LDA offer data for the 2021/2022 RPM Base Residual Auction. Total internal BGE LDA unforced capacity, excluding generation winter capacity, of 3,838.2 MW includes all Generation Capacity Resources, Demand Resources, and Energy Efficiency Resources that qualified as PJM Capacity Resources, excludes external units, and also includes owners' modifications to ICAP ratings. As shown in Table 14, BGE LDA unforced internal capacity decreased 102.3 MW from 3,940.5 MW in the 2020/2021 BRA as a result of net generation capacity modifications (0.0 MW), net DR modifications (-103.6 MW), and net EE modifications (-54.7 MW), the EFORd effect due to lower sell offer EFORds (55.5 MW), and the DR and EE effect due to a higher Load Management UCAP conversion factor (0.5 MW). As shown in Table 16, total internal BGE unforced winter capacity increased by 0.0 MW for November through April of the 2021/2022 Delivery Year.

162 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.[163] Total internal BGE LDA capacity was reduced by FRR commitments of 0.0 MW, resulting in BGE LDA RPM capacity of 3,838.2 MW. RPM capacity was reduced by 0.0 MW of exports, 0.0 MW of FRR optional volumes not offered, 338.6 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 1.7 MW of intermittent resources and 0.0 MW of capacity storage resources which were not subject to the CP must offer requirement. Subtracting 110.4 MW of DR and EE not offered and 0.0 MW of unoffered generation winter capacity resulted in available unforced capacity in BGE LDA of 3,387.5 MW.[164] After accounting for these exceptions, all capacity resources in BGE LDA were offered in the RPM Auction.

The BGE LDA import limit was a binding constraint in the 2021/2022 BRA. Of the 1,937.7 MW cleared in BGE LDA, 915.0 MW were cleared in the RTO before BGE LDA became constrained. Once the constraint was binding, based on the 6,005.0 MW CETL value, only the incremental supply located in BGE LDA was available to meet the incremental demand in the LDA. Of the incremental supply, 1,022.7 MW cleared, which resulted in a clearing price for Capacity Performance Resources of $200.30 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 11, the 1,833.3 MW of cleared and make whole generation and DR for BGE LDA and 6,005.0 MW CETL resulted in a net excess of 189.9 MW.

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

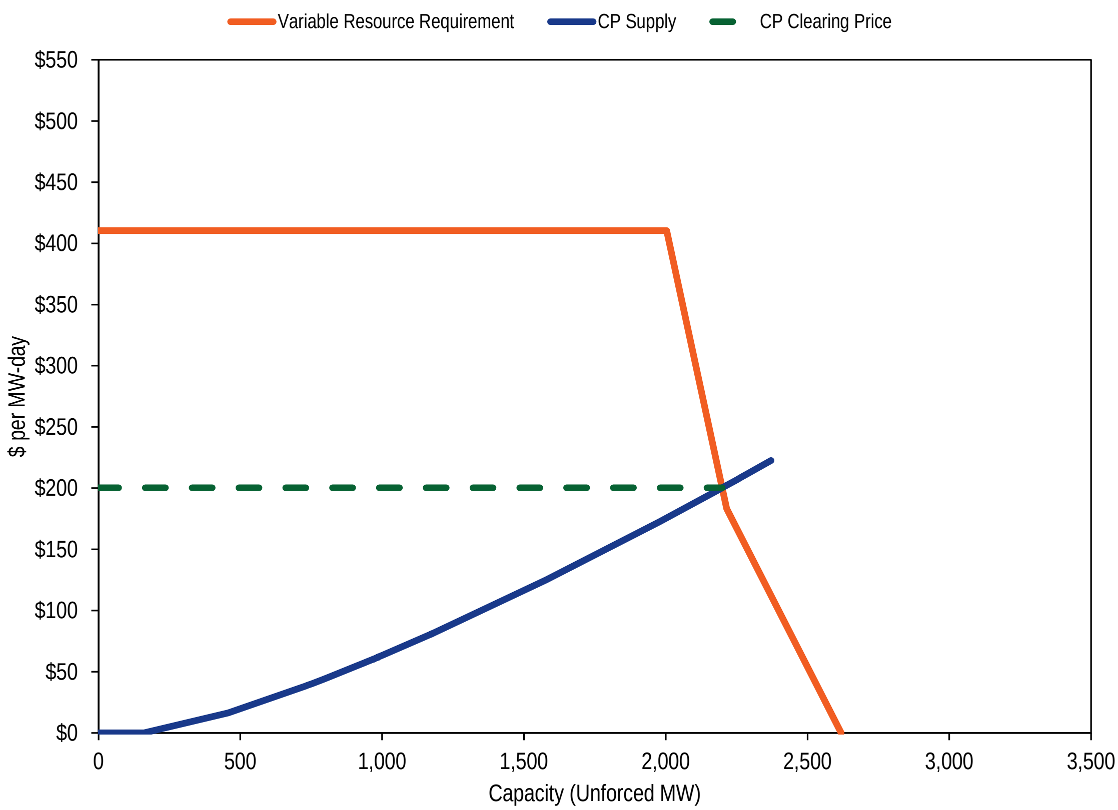
164 Unoffered DR and EE MW include PJM approved DR and EE plans that were not offered in the auction.

Table and Figure for BGE LDA

Table 52 BGE LDA offer statistics: 2021/2022 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	3,527.2	3,329.8		
DR capacity	370.0	403.3		
EE capacity	96.4	105.1		
Generation winter capacity	0.0	0.0		
Total internal BGE LDA capacity	3,993.6	3,838.2		
FRR	0.0	0.0		
Imports	0.0	0.0		
RPM capacity	3,993.6	3,838.2		
Exports	0.0	0.0		
FRR optional	0.0	0.0		
Excused Existing Generation Capacity Resources	(350.5)	(338.6)		
Unoffered Planned Generation Capacity Resources	0.0	0.0		
Unoffered Intermittent Resources	(4.0)	(1.7)		
Unoffered Capacity Storage Resources	0.0	0.0		
Unoffered generation winter capacity	0.0	0.0		
Unoffered DR and EE	(100.6)	(110.4)		
Available	3,538.5	3,387.5	100.0%	100.0%
Generation offered	3,172.7	2,989.5	89.7%	88.3%
DR offered	270.1	293.7	7.6%	8.7%
EE offered	95.8	104.3	2.7%	3.1%
Total offered	3,538.5	3,387.5	100.0%	100.0%
Unoffered Existing Generation Capacity Resources	0.0	0.0	0.0%	0.0%

Figure 6 BGE LDA market supply/demand curves: 2021/2022 RPM Base Residual Auction[165]



165 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.[166] 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

166 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 2021/2022 RPM Base Residual Auction conducted by PJM were replicated using the MMU's approach. The total MW cleared for every constrained nested LDA using the MMU's algorithm is identical to the corresponding total MW cleared under PJM's method. The total MW cleared for the entire RTO using the MMU's algorithm is identical to the total MW cleared under PJM's method. The clearing prices using the PJM's approach were identical to the clearing prices under MMU's method.

Recommendations for the RPM Market Clearing

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

Absent a fully nodal capacity market clearing process, the MMU recommends that PJM use non-nested model with all LDAs and specify VRR curves for each LDA. Each LDA requirement should be met with the capacity resources located within the LDA and exchanges from neighboring LDAs up to the transmission limit. LDAs should be allowed to price separate if that is the result of the LDA supply curves and the transmission constraints.

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

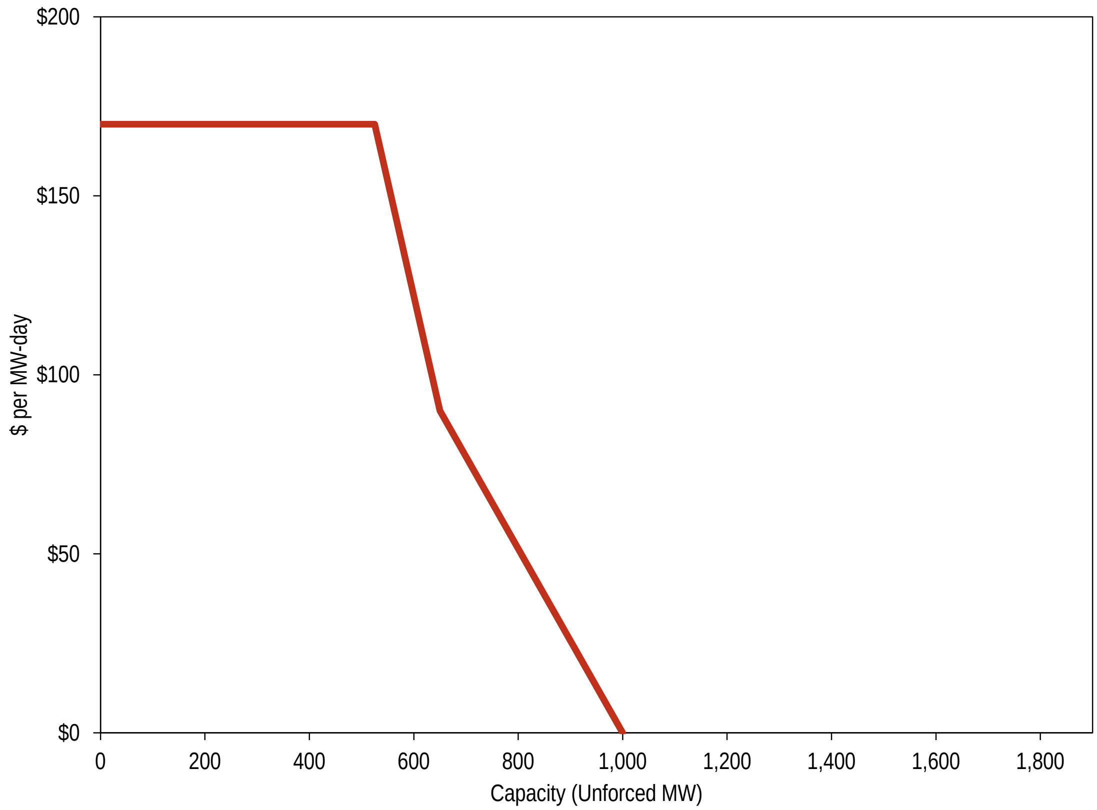
The MMU recommends improving the RPM solution method related to make whole payments. The MMU recommends changing the RPM solution method to explicitly incorporate the cost of make whole payments in the objective function.

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.[167]

Figure 7 Variable resource requirement curve: child LDA



[167] 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

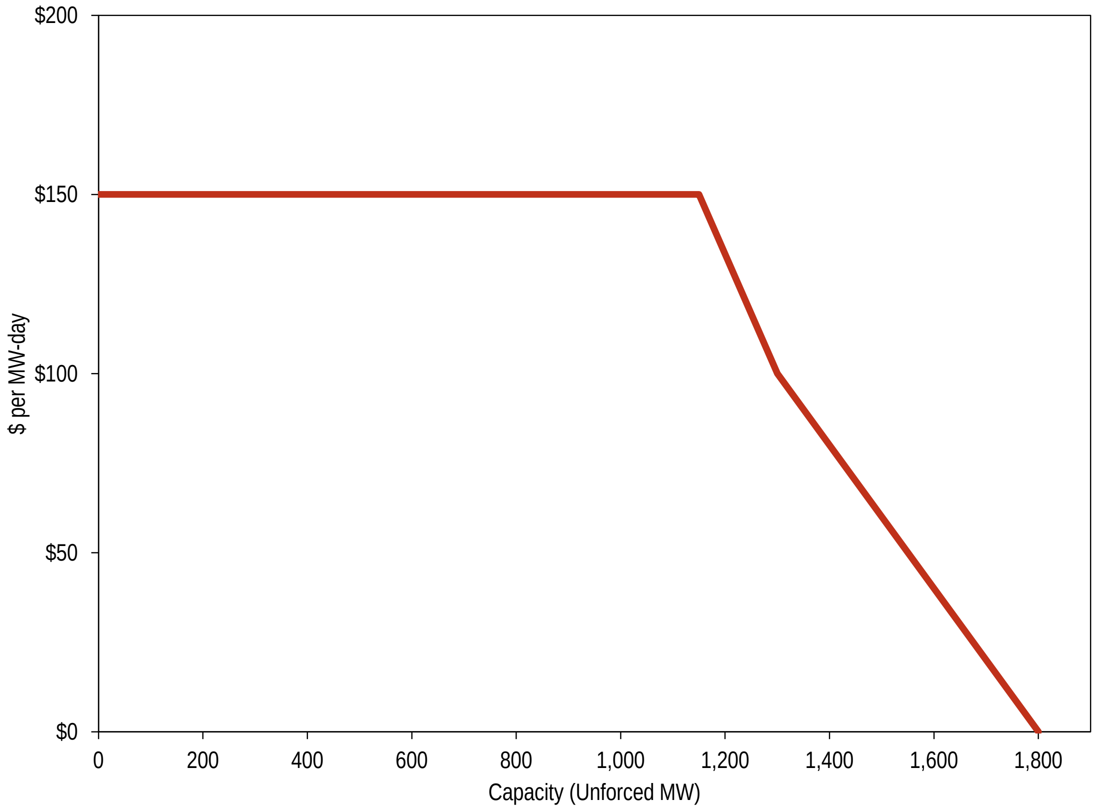


Figure 9 and Figure 10 illustrate the solution for the first scenario. Only 189.1 MW of the available 300 MW CETL is utilized. Therefore the CETL constraint is non-binding and out of merit offers are not needed to meet the child LDA's Variable Resource Requirement. The marginal clearing price for both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

Figure 9 Optimal solution for scenario 1: child LDA

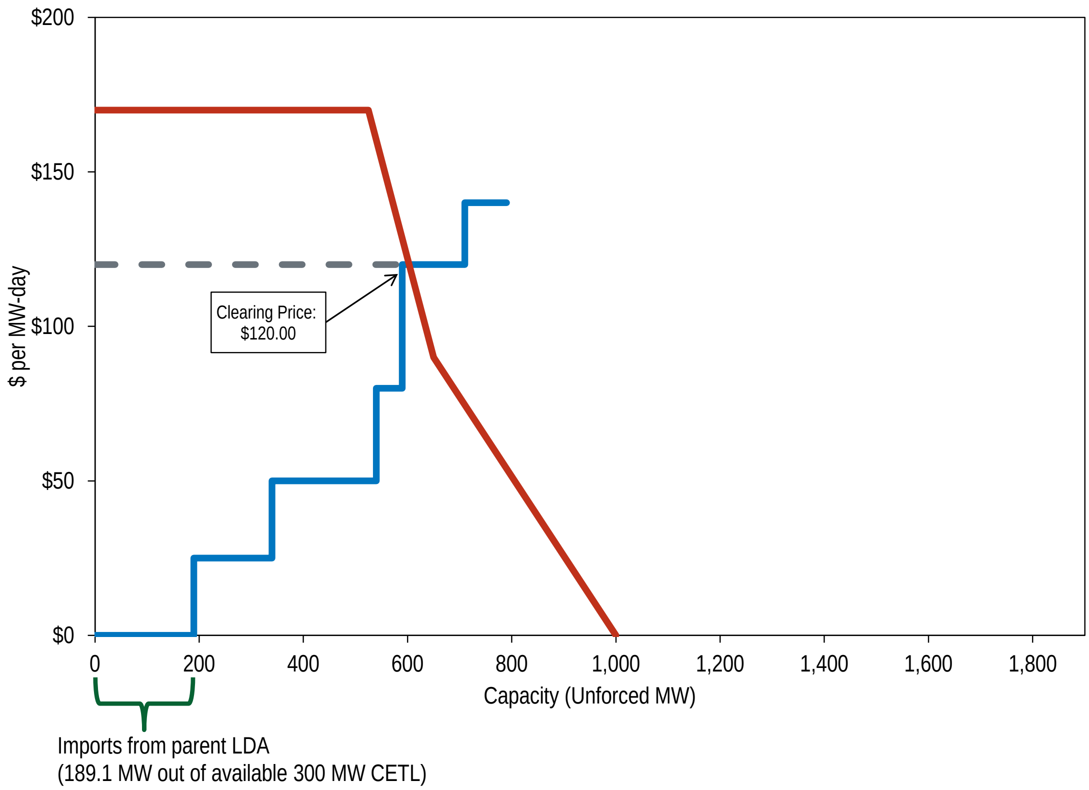


Figure 10 Optimal solution for scenario 1: Parent LDA

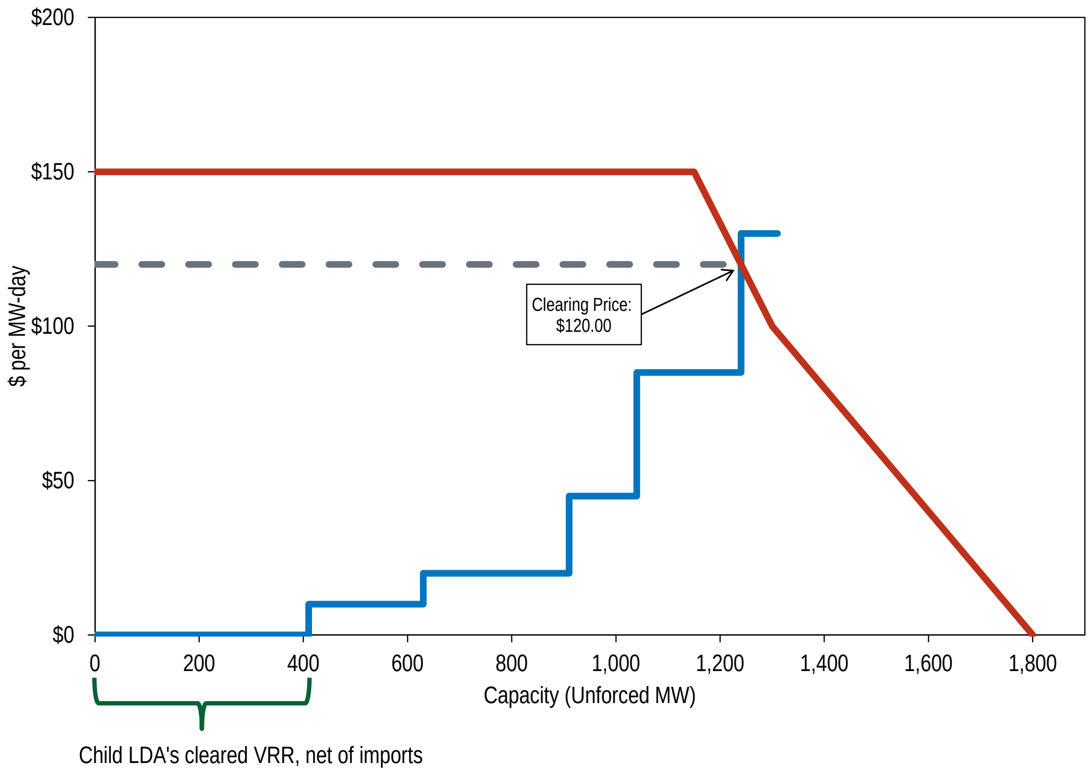


Figure 11 and Figure 12 illustrate the solution for the second scenario. The only difference between first and second scenarios is that the CETL is 150 MW in the second scenario compared to 300 MW in the first scenario. The solution shows that the entire 150 MW available is utilized by the child LDA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

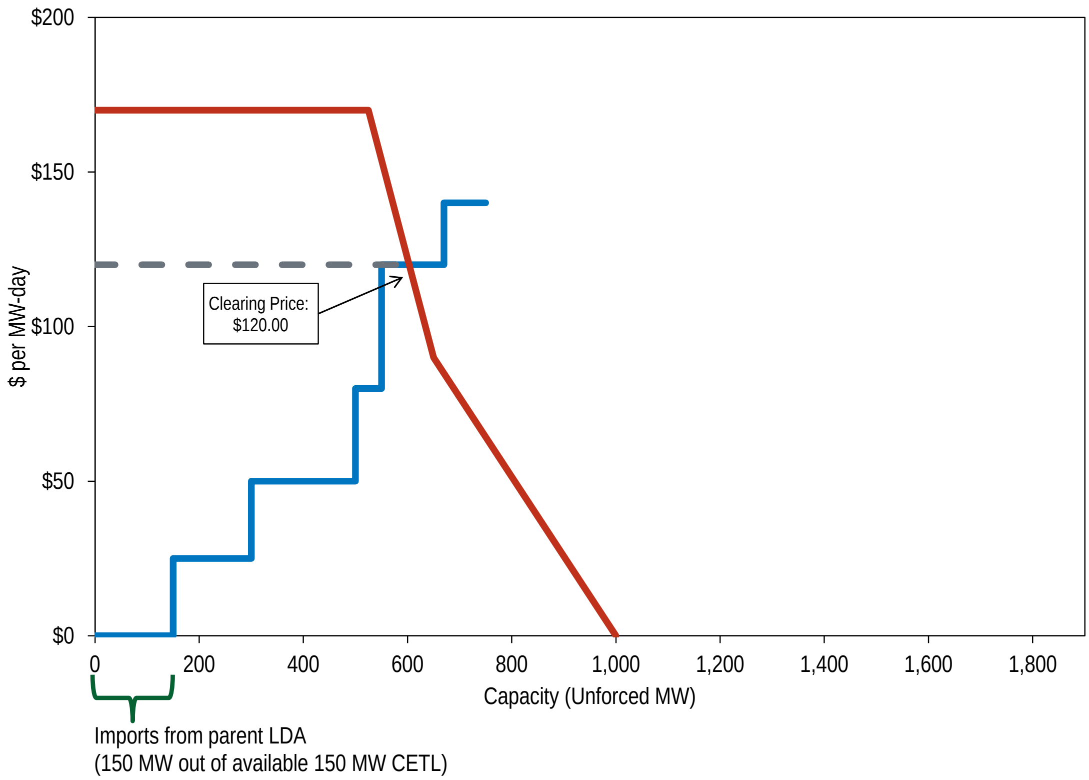
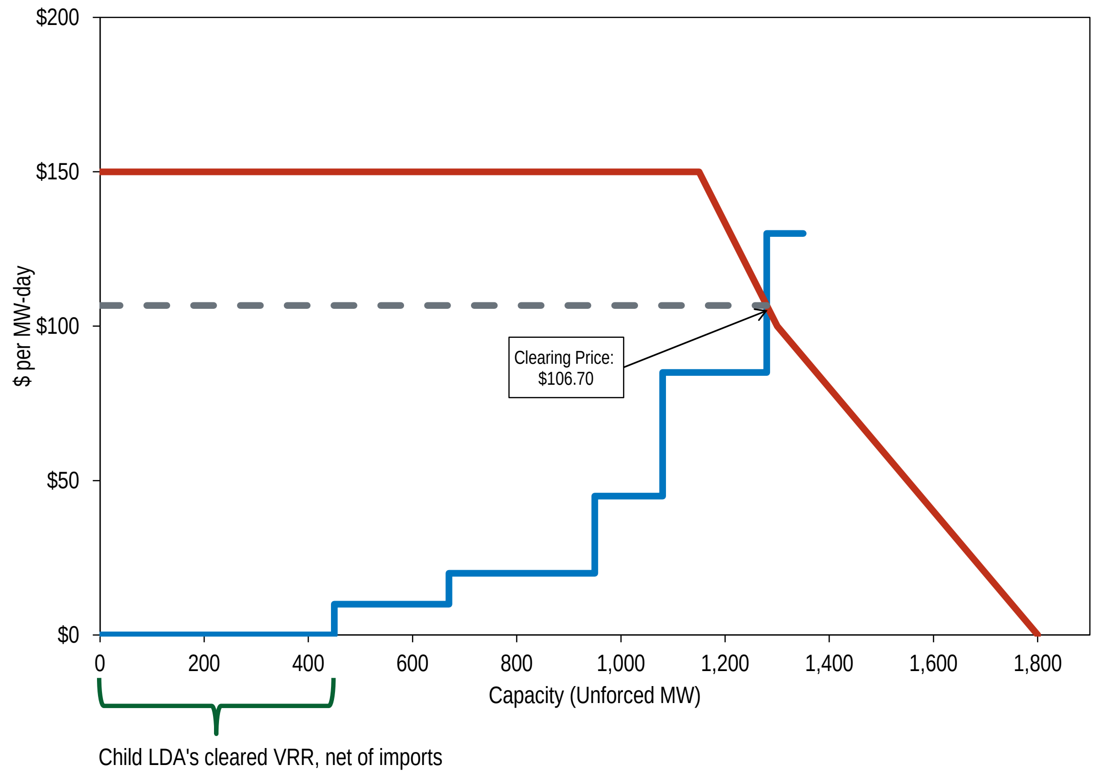


Figure 12 Optimal solution for scenario 2: Parent LDA



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

$A_i = (MW_i/UCAP)$, availability during performance assessment interval i, calculated as the MW power output in an interval divided by the MW UCAP of the resource. The MWh output in an interval is equal to one-twelfth of the MW power output of the resource.

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

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

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

H – expected value of total number of performance assessment intervals in a delivery year

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

CPBR – average capacity performance bonus rate over all performance assessment intervals ($ per MWh) 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 PAI:

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

$$R^c = UCAP \times [p + \ (PPR \times H \times (\bar{A} - \bar{B}))/12] - UCAP \times ACR \tag{1}$$

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:

$$R^{nc} = UCAP \times \left[\ (1/12) \sum_{i=1}^{H} (CPBR_i \times A_i)\right] - UCAP \times ACR \tag{2}$$

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 intervals.

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.

$$if\ ACR \leq \left(\frac{1}{12}\right) \sum_{i=1}^{H} (CPBR_i \times A_i)$$

$$or\ ACR \leq (CPBR \times H \times \bar{A})/12$$

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:

$$p \geq \left(\frac{1}{12}\right)\left[\sum_{i=1}^{H} CPBR_i \times (A_i)\right] - \left(\frac{1}{12}\right)(PPR \times H \times (\bar{A} - \bar{B}))$$

$$or, p \geq \frac{PPR \times H \times \bar{B}}{12} + \left(\frac{1}{12}\right)\left[\sum_{i=1}^{H} CPBR_i \times (A_i)\right] - \frac{PPR \times H \times \bar{A}}{12}$$

Using the weighted average capacity performance bonus rate,

$$p \geq \left(\frac{1}{12}\right)[PPR \times H \times \bar{B} + CPBR \times H \times \bar{A} - PPR \times H \times \bar{A}]$$

Therefore the competitive offer is:

$$p = \left(\frac{1}{12}\right)\ [CPBR \times H \times \bar{A} + PPR \times H \times (\bar{B} - \bar{A})] \tag{3}$$

Equation (3) is the competitive offer formula for a low ACR resource with $A_i < B_i$ for all PAI. 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:

$$p = \left(\frac{1}{12}\right)\left[CPBR \times H \times \bar{A} + \left(\frac{Net\ CONE}{30}\right) \times H \times (\bar{B} - \bar{A})\right] \tag{4}$$

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 assessment intervals, H, is expected to be 360 (30 hours), this is identical to:

$$p = \ Net\ CONE \times \bar{B} \tag{5}$$

These are the assumptions made in the PJM filing and result in the definition of the competitive offer cap in the PJM filing. However, if the expected number of performance assessment intervals(H) is updated to a smaller number, say 60 intervals (5 hours), and if the assumption of a low ACR resource still holds true ($ACR \leq (CPBR \times H \times \bar{A})/12$), the competitive offer for such a resource is:

$$p = \left(\frac{1}{12}\right)\left[\left(\frac{Net\ CONE}{30}\right) \times 60 \times \bar{A} + \left(\frac{Net\ CONE}{30}\right) \times 60 \times (\bar{B} - \bar{A})\right]$$

$$p = \left(\frac{1}{6}\right)[Net\ CONE \times \bar{B}]$$

Under this updated estimate for the number of performance assessment intervals, more resources are likely to have their net ACR greater than the energy only bonuses, and become 'High ACR' resources. The competitive offers for High ACR resources are discussed in the following section.

The actual capacity performance bonus rate (CPBR) will depend on the level of nonperformance charges collected from underperforming resources during each performance assessment interval. 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.

$$if\ ACR > \left(\frac{1}{12}\right)\left[\sum_{i=1}^{H}(CPBR_i \times A_i)\right]$$

$$or\ ACR > (CPBR \times H \times \bar{A})/12$$

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 PAI 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):

$$UCAP \times [p + \ (PPR \times H \times (\bar{A} - \bar{B}))/12] - UCAP \times ACR \geq 0$$

$$or, p \geq ACR + (PPR \times H \times (\bar{B} - \bar{A}))/12$$

The competitive offer is:

$$p = ACR + (PPR \times H \times (\bar{B} - \bar{A}))/12 \tag{6}$$

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 $(PPR \times H \times (\bar{B} - \bar{A}))/12$ in both equations. For a unit to be High ACR, $ACR > (CPBR \times H \times \bar{A})/12$. 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 PAI:

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

$$R^c = UCAP \times p + UCAP \times \left(\frac{1}{12}\right)\left[\sum_{i=1}^{H} CPBR_i \times (A_i - B_i)\right] - UCAP \times ACR \quad (7)$$

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:

$$R^{nc} = UCAP \times \left(\frac{1}{12}\right)\left[\sum_{i=1}^{H}(CPBR_i \times A_i)\right] - UCAP \times ACR \quad (8)$$

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 intervals.

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.

$$if\ ACR \leq \left(\frac{1}{12}\right)\sum_{i=1}^{H}(CPBR_i \times A_i)$$

$$or\ ACR \leq (CPBR \times H \times \bar{A})/12$$

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:

$$p \geq \left(\frac{1}{12}\right)\left[\sum_{i=1}^{H} CPBR_i \times (B_i)\right]$$

$$or, p \geq (CPBR \times H \times \bar{B})/12 \qquad (9)$$

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

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 intervals, H, is expected to be 360, this is identical to:

$$p = net\ CONE \times \bar{B} \qquad (10)$$

These are the assumptions made in the PJM filing and result in the definition of the competitive offer cap in the PJM filing. However, if the expected number of performance assessment intervals(H) is updated to a smaller number, say 60 intervals (5 hours), and if the assumption of a low ACR resource still holds true ($ACR \leq (CPBR \times H \times \bar{A})/12$), the competitive offer for such a resource is:

$$p = \left(\left(\frac{net\ CONE}{30}\right) \times 60 \times \bar{B}\right)/12$$

$$p = \left(\frac{1}{6}\right)[net\ CONE \times \bar{B}]$$

Under this updated estimate for the number of performance assessment intervals, more resources are likely to have their net ACR greater than the energy only bonuses, and become 'High ACR' resources. The competitive offers for High ACR resources are discussed in the following section.

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.

$$if\ ACR > \left(\frac{1}{12}\right)\left[\sum_{i=1}^{H}(CPBR_i \times A_i)\right]$$

$$or\ ACR > (CPBR \times H \times \bar{A})/12$$

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 PAI 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):

$$UCAP \times p + UCAP \times \left(\frac{1}{12}\right)\left[\sum_{i=1}^{H} CPBR_i \times (A_i - B_i)\right] - UCAP \times ACR \geq 0$$

$$or, p \geq ACR + \left(\frac{1}{12}\right) \times CPBR \times H \times (\bar{B} - \bar{A})$$

The competitive offer is:

$$p = ACR + (CPBR \times H \times (\bar{B} - \bar{A}))/12 \quad (11)$$

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, $ACR > (CPBR \times H \times \bar{A})/12$. 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 $(PPR \times H \times \bar{B})/12$ regardless of the performance of the unit and the competitive offer for a High ACR unit is equal to $ACR + (PPR \times H \times (\bar{B} - \bar{A}))/12$ regardless of the performance of the unit.

Revision History

August 9, 2018: Original document posted.

August 24, 2018: Scenario 21 Impact of noncompetitive offers was revised.

October 4, 2019: Capacity Transmission Rights values were revised.