Monitoring Analytics

# Analysis of the 2016/2017 RPM Base Residual Auction

The Independent Market Monitor for PJM

April 18, 2014

## Introduction

This report, prepared by the Independent Market Monitor for PJM (IMM or MMU), reviews the functioning of the tenth Reliability Pricing Model (RPM) Base Residual Auction (BRA) (for the 2016/2017 Delivery Year) and responds to questions raised by PJM members and market observers about that auction. The MMU prepares a report for each RPM Auction.

This report addresses, explains and quantifies the basic market outcomes. This report also addresses and quantifies the impact on market outcomes of: the Short-Term Resource Procurement Target; Demand Resources (DR); the definition of Demand Resource products; Avoidable Project Investment Recovery Rate (APIR) changes related to environmental regulations; and capacity imports.

## Conclusions and Recommendations

The capacity market is, by design, always tight in the sense that total supply is generally only slightly larger than demand. While the market may be long at times, that is not the equilibrium state. Capacity in excess of demand is not sold and, if it does not earn or does not expect to earn adequate revenues in future capacity markets, or in other markets, or does not have value as a hedge, may be expected to retire. The demand for capacity includes expected peak load plus a reserve margin, and points on the Variable Resource Requirement (VRR) curve exceed peak load plus the reserve margin. Thus, the reliability goal is to have total supply equal to or slightly above the demand for capacity. The level of purchased demand under RPM has generally exceeded expected peak load plus the target reserve margin, resulting in reserve margins that exceed the target. Demand is almost entirely inelastic because the market rules require loads to purchase their share of the system capacity requirement. The level of elasticity incorporated in the RPM demand curve, called the Variable Resource Requirement (VRR) curve, is not adequate to modify this conclusion. The result is that any supplier that owns more capacity than the typically small difference between total supply and the defined demand is individually pivotal and therefore has structural market power. Any supplier that, jointly with two other suppliers, owns more capacity than the difference between supply and demand either in aggregate or for a local market is jointly pivotal and therefore has structural market power.

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 existing 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). This represents a significant advance over the prior capacity market design.

Reliance on the RPM design for competitive outcomes means reliance on the market power mitigation rules. Attenuation of those rules would mean that market participants would not be able to rely on the competitiveness of the market outcomes. However, the market power rules are not perfect and, as a result, competitive outcomes require continued improvement of the rules and ongoing monitoring of market participant behavior and market performance.

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

The MMU verified the reasonableness of offer data and calculated the derived offer caps based on submitted data; calculated unit net revenues; reviewed requests for exceptions to the Minimum Offer Price Rule (MOPR); reviewed offers for Planned Generation Capacity Resources; verified capacity exports; verified offers based on opportunity costs; verified the reasons for MW not offered; verified the maximum sell offer Equivalent Demand Forced Outage Rates (EFORds); verified clearing prices based on the demand (VRR) curves and the minimum resource requirements; and verified that the market structure tests were applied correctly.[1] All participants in the RTO, MAAC, PSEG, and ATSI RPM markets failed the three pivotal supplier (TPS) test. The result was that offer caps were applied to all sell offers for Existing Generation Capacity Resources when the Capacity Market Seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would have resulted in a higher market clearing price.[2] [3] The offer caps are designed to reflect the marginal cost

---

1 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.

2 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.

3 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).

of capacity. Based on the data and this review, the MMU concludes that the results of the 2016/2017 RPM Base Residual Auction were competitive.

Nonetheless, there are significant issues with the RPM market design which have significant consequences for market outcomes.

In particular, the MMU recommends that the use of the 2.5 percent demand adjustment (Short-Term Resource Procurement Target) be terminated immediately. The MMU recommends the enforcement of a consistent definition of capacity resource. The MMU recommends that the requirement to be a physical resource be enforced and enhanced. The requirement to be a physical resource should apply at the time of auctions and should also constitute a commitment to be physical in the relevant delivery year. The requirement to be a physical resource should be applied to all resource types, including planned generation, demand resources and imports.[4] [5] The MMU recommends 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. Both the Limited and the Extended Summer DR products should be eliminated and the restrictions on the availability of Annual DR should be eliminated in order to ensure that the DR product has the same unlimited obligation to provide capacity year round as Generation Capacity Resources. The MMU recommends that the net revenue calculation used by PJM to calculate the net 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.[6] [7] 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

---

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

5 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2013," <http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Report_on_Capacity_Replacement_Activity_2_20130913.pdf> (September 13, 2013).

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

7 See the *2012 State of the Market Report for PJM*, Volume II, Section 6, Net Revenue.

assumptions. That is the only way to ensure that projects compete on the basis of actual costs rather than on the basis of modeling assumptions.[8]

The MMU recommends two changes to the RPM solution methodology related to make-whole payments and the iterative reconfiguration of the VRR curve.[9] The MMU recommends changing the RPM solution methodology to explicitly incorporate the cost of make-whole payments in the objective function. The MMU also recommends changing the RPM solution methodology to define variables for the nesting relationships in the BRA optimization model directly rather than employing the current iterative approach, in order to improve the efficiency and stability.

## Results

The 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 6, the 159,159.7 MW of cleared resources for the entire RTO, which represented a reserve margin of 21.5 percent not considering Fixed Resource Requirement (FRR) load, resulted in net excess of 7,185.4 MW over the reliability requirement of 166,127.5 MW.

The Short-Term Resource Procurement Target had a significant impact on the auction results. The removal of 2.5 percent of demand significantly reduced the clearing prices and quantities for all the RPM LDA markets. The clearing quantities of Annual Resources, including generation and DR, were reduced as a result of the 2.5 percent demand reduction. Based on actual auction clearing prices and quantities and make-

---

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

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

whole MW, total RPM market revenues for the 2016/2017 RPM Base Residual Auction were $5,513,237,849. If the VRR curves had not been reduced by the Short-Term Resource Procurement Target, total RPM market revenues for the 2016/2017 RPM Base Residual Auction would have been $6,894,277,704, an increase of $1,381,039,855, or 25 percent, compared to the actual results. The use of the Short-Term Resource Procurement Target resulted in a 20 percent reduction in RPM revenues for the 2016/2017 Base Residual Auction.

The inclusion of inferior demand side products in the auction also had a significant impact on the auction results. Based on actual auction clearing prices and quantities, total RPM market revenues for the 2016/2017 RPM Base Residual Auction were $5,513,237,849. If only generation and Annual DR were offered in the 2016/2017 RPM Base Residual Auction, total RPM market revenues for the 2016/2017 RPM Base Residual Auction would have been $10,141,586,456, an increase of $4,628,348,607, or 84 percent, compared to the actual results. The inclusion of the Limited and Extended Summer DR products resulted in a 46 percent reduction in RPM revenues for the 2016/2017 Base Residual Auction.

The combination of the Short-Term Resource Procurement Target and inferior demand side products 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 2016/2017 RPM Base Residual Auction were $5,513,237,849. If the VRR curves had not been reduced by the Short-Term Resource Procurement Target and only generation and Annual DR were offered in the 2016/2017 RPM Base Residual Auction, total RPM market revenues for the 2016/2017 RPM Base Residual Auction would have been $15,834,365,769, an increase of $10,321,127,920, or 187 percent, compared to the actual results. The use of the Short-Term Resource Procurement Target together with the inclusion of the Limited and Extended Summer DR products resulted in a 65 percent reduction in RPM revenues for the 2016/2017 RPM Base Residual Auction.

The inclusion of sell offers for Demand 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 2016/2017 RPM Base Residual Auction were $5,513,237,849. If there were no offers for DR in the 2016/2017 RPM Base Residual Auction, total RPM market revenues for the 2016/2017 RPM Base Residual Auction would have been $15,630,600,107, an increase of $10,117,362,259, or 184 percent, compared to the actual results. The inclusion of Demand Resources resulted in a 65 percent reduction in RPM revenues for the 2016/2017 RPM Base Residual Auction.

The inclusion of sell offers for Annual DR alone 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 2016/2017 RPM Base Residual Auction were $5,513,237,849. If only generation and Annual DR were offered in the 2016/2017 RPM

Base Residual Auction, total RPM market revenues for the 2016/2017 RPM Base Residual Auction would have been $10,141,586,456. If there were no offers for DR in the 2016/2017 RPM Base Residual Auction, total RPM market revenues for the 2016/2017 RPM Base Residual Auction would have been $15,630,600,107, an increase of $5,489,013,652, or 54 percent, compared to the results with only Annual DR. The inclusion of sell offers for Annual DR alone resulted in a 35 percent reduction in RPM revenues for the 2016/2017 RPM Base Residual Auction compared to the revenues without any DR products.

This is the best measure of the competitive impact of DR on the RPM market. The Annual DR product definition is the only one consistent with being a capacity resource. Assuming that the DR meets appropriate measurement and verification standards and that the DR was offered with the intention of providing physical resources, competition from the Annual DR product resulted in a 35 percent reduction of payments for capacity. This demonstrates that Annual DR had a significant impact on market outcomes and resulted in the displacement of generation resources. Thus, even when the DR product is limited to the Annual DR product, DR has a significant and appropriate competitive impact on capacity market outcomes. As in prior BRAs, Extended Summer and Limited DR products also had a significant impact in the 2015/2016 BRA, but those impacts resulted from badly defined and inferior products.

The level of DR products that buy out of their positions after the BRA however suggests that the impact of DR on generation investment incentives needs to be carefully considered and the rules governing the requirement to be a physical resource are enforced.[10] 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 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 investments based on environmental regulation compliance, including the EPA's Mercury and Air Toxics Standards (MATS) rules and the National Emissions Standards for Hazardous Air Pollutants (NESHAP) for stationary reciprocating internal combustion engines (RICE) rules and the NJ High Electric Demand Day (HEDD) Rule, had a significant impact on the auction results. Of the 13,081.7 MW of uncleared offers

---

10 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2013" <http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Report_on_Capacity_Replacement_Activity_2_20130913.pdf> (September 13, 2013).

for generation resources, 5,333.8 MW were offers for resources including costs associated with environmental regulation compliance that were not previously included in APIR. Based on actual auction clearing prices and quantities and make-whole MW, total RPM market revenues for the 2016/2017 RPM Base Residual Auction were $5,513,237,849. If the APIR associated with the pending environmental regulations which had not been previously submitted were removed, total RPM market revenues for the 2016/2017 RPM Base Residual Auction would have been $5,310,133,190, a reduction of $203,104,659, or 3.7 percent, compared to the total based on actual results. The impact of including environmental compliance costs in APIR was to increase total market revenues by $203,104,659, or 3.8 percent.

The inclusion of capacity imports in the 2016/2017 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 2016/2017 RPM Base Residual Auction were $5,513,237,849. If offers for external generation were reduced by 25 percent, total RPM market revenues for the 2016/2017 RPM Base Residual Auction would have been $6,150,779,857, an increase of $637,542,008, or 12 percent, compared to the actual results. The impact of including 75 percent of the offers for external generation resources was to decrease total market revenues by $637,542,008, or 10 percent. If offers for external generation were reduced by 75 percent, total RPM market revenues for the 2016/2017 RPM Base Residual Auction would have been $7,814,811,849, an increase of $2,301,574,000, or 42 percent, compared to the actual results. The impact of including 25 percent of the offers for external generation resources was to decrease total market revenues by $2,301,574,000, or 29 percent.

If offers for external generation resources without firm transmission were excluded, total RPM market revenues for the 2016/2017 RPM Base Residual Auction would have been $6,810,335,209, an increase of $1,297,097,360, or 24 percent, compared to the actual results. The impact of including external generation resources with only firm transmission was to decrease total market revenues by $1,297,097,360, or 19 percent. The impact of increased imports is comparatively high in the RTO because all imports are considered to be imports to the RTO. If offers for external generation resources without firm transmission were excluded, the RTO clearing price for Limited Resources would have increased to $90.00 per MW-day, and the clearing quantity would have increased to 10,186.8 MW. The RTO clearing price for Extended Summer and Annual Resources would have increased to $95.00 per MW-day, and the clearing quantity would have increased to 158,512.2 MW.

## Clearing Prices

Table 1 shows the clearing prices for Annual Resources in the 2016/2017 BRA by LDA compared to the corresponding net Cost of New Entry (CONE) values. The clearing prices for Annual Resources were less than net CONE for every Locational Deliverability Area (LDA).

**Table 1 Clearing prices and net CONE: 2016/2017 RPM Base Residual Auction**

| LDA | Annual Clearing Price ($ per MW-day) | Net CONE ($ per MW-day) | Annual Clearing Price to Net CONE |
|---|---|---|---|
| RTO | $59.37 | $330.53 | 18.0% |
| MAAC | $119.13 | $276.90 | 43.0% |
| EMAAC | $119.13 | $329.94 | 36.1% |
| SWMAAC | $119.13 | $276.90 | 43.0% |
| PSEG | $219.00 | $329.94 | 66.4% |
| PSEG North | $219.00 | $329.94 | 66.4% |
| DPL South | $119.13 | $329.94 | 36.1% |
| Pepco | $119.13 | $276.90 | 43.0% |
| ATSI | $114.23 | $362.64 | 31.5% |
| ATSI Cleveland | $114.23 | $362.64 | 31.5% |

## *Market Changes*

### RPM Market Design Changes

### RPM Must Offer Requirement and Market Power Mitigation

The 2016/2017 RPM Base Residual Auction was the third BRA conducted under the revised RPM rules effective January 31, 2011, related to the RPM must-offer requirement and market power mitigation.[11] These changes included clarifying the applicability of the must-offer requirement and the circumstances under which exemptions from the RPM must-offer requirement would be allowed, revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must-offer requirement and mitigation, treating a proposed increase in the capability of a Generation Capacity Resource in exactly the same way as a Planned Generation Capacity Resource for purposes of market power mitigation.

The 2016/2017 RPM Base Residual Auction was the first BRA conducted under the process improvement PJM Tariff revisions.[12] 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.

---

11 134 FERC ¶ 61,065 (2011).

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

## MOPR

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

Effective April 12, 2011, the RPM Minimum Offer Price Rule (MOPR) was changed.[13] 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 percentage 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 2015/2016 RPM Base Residual Auction was the second BRA conducted under the revised MOPR and the first 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.[14]

Effective May 3, 2013, the RPM Minimum Offer Price Rule (MOPR) was changed again.[15] The changes to the MOPR included establishing Competitive Entry and Self Supply Exemptions while also retaining the unit specific exemption process for those 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.

---

[13] 135 FERC ¶ 61,022 (2011).

[14] 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.

[15] 143 FERC ¶ 61,090 (2013).

## 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.[16] [17] [18] The default ACRs for the 2016/2017 Delivery Year were 9.5 percent lower than the values would have been if the calculation method had remained the same.

The FERC Order also approved updates to the base default ACR values and consolidation of the ACR technology classifications, which become effective for the 2017/2018 and subsequent Delivery Years. The default ACR values for the 2016/2017 Delivery Year were calculated by applying the applicable annual rate of change in the Handy-Whitman Index value to update the base values through 2012/2013 for which data were available and applying the most recent ten year annual average rate of change in the Handy-Whitman Index to recalculate the default ACR values for 2013/2014 through 2015/2016 prior to estimating the default ACR values for the 2016/2017 Delivery Year.

## Gross CONE

Effective January 20, 2013, the gross CONE values for the 2015/2016 Delivery Year were updated as part of a Settlement Agreement.[19] Between triennial 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.

## Demand Resource Rules

Effective January 31, 2013, a third test for determining the Limited DR Reliability Target was implemented to ensure that the probability of requiring an interruption of longer

16 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).

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

18 142 FERC ¶ 61,092 (2013).

19 142 FERC ¶ 61,079 (2013).

than six hours, which is the maximum duration of an interruption for a Limited DR product, is minimal.[20]

Effective with the 2014/2015 Delivery Year, the RPM market design incorporated Annual and Extended Summer DR product types, in addition to the previously established Limited DR product type.[21] 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 include the establishment of a maximum level of Limited DR and a maximum level of Extended Summer DR cleared in the auction, which are 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 is established.[22] Annual Resources include generation resources, Annual DR, and EE.

The Minimum Resource Requirements are targets established by PJM to ensure that a sufficient amount of Annual Resources are 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 are 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 are 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 will seek to procure from Annual Resources in order to maintain reliability based on a PJM analysis of the probability of needing Limited DR resources.[23] The Minimum Extended Summer Resource Requirement is the minimum amount of capacity that PJM will 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 will purchase to meet reliability requirements, because additional purchases of these products is not consistent with reliability based on a PJM analysis of the probability of needing Limited DR resources when they are not available.

---

20 143 FERC ¶ 61,076 (2013).

21 134 FERC ¶ 61,066 (2011).

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

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

The maximum level of Limited and Extended Summer DR is 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 are linked sell offers for a Demand Resource that is 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 may be coupled, and the Capacity Market Seller must specify 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 will result in a higher price for Annual Resources if the MW of Annual Resources that would otherwise clear the auction, including all resources, are less than the Minimum Annual Resource Requirement that PJM requires for reliability. In that case the auction clearing mechanism will select Annual Resources that are more expensive than the clearing price that would otherwise result in order to procure the defined Minimum Annual Resource Requirement. PJM's auction clearing mechanism will also result in a higher price for Extended Summer Resources if the MW of Extended Summer Resources that would otherwise clear the auction are less than the Minimum Extended Summer Resource Requirement that PJM requires for reliability. In that case the auction clearing mechanism will select Extended Summer Resources that are more expensive than the clearing price that would otherwise result 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 will receive a price adder to the system marginal price, in addition to any locational price adders needed to resolve locational constraints.

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 Delivery Year, 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.[24] [25] Capacity Market Sellers

[24] Letter Order issued in Docket No. ER11-2913-000 (April 13, 2011).

utilizing coupled sell offers cannot use the MPCE option. The intent of credit limited offers is to allow Capacity Market Sellers to better manage their credit requirement by specifying the maximum amount of credit they are willing to incur and to provide the service of determining the maximum cleared MW given the MPCE limit. For DR, 20 percent of MW offered used MPCE while for Energy Efficiency (EE) resources, eight percent of MW offered used MPCE.

Under the new 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 Delivery Year, the RPM credit rate prior to the posting of the BRA results is equal to the greater of $20 per MW-day or 30 percent of the LDA net Cost of New Entry times the number of days in the delivery year, and the RPM credit rate after posting the BRA results is the greater of $20 per MW-day or 20 percent of the LDA resource clearing price for the relevant product type times the number of days in the delivery year.[26] 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.

Effective January 31, 2012, the 2.5 percent holdback is not subtracted from the Minimum Annual and Extended Summer Resource Requirements.[27] 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 is 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

---

25 PJM. "Manual 18: PJM Capacity Market," Revision 19 (June 1, 2013), p. 71-72.

26 PJM. "Manual 18: PJM Capacity Market," Revision 19 (June 1, 2013), p. 71.

27 138 FERC ¶ 61,062 (2012).

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.

## Preliminary Market Structure Screen

The preliminary market structure screen (PMSS) was eliminated effective December 17, 2012.[28] The 2016/2017 RPM Base Residual Auction was the first BRA held after the PMSS was eliminated.

## Other Changes Affecting Supply and Demand

The East Kentucky Power Cooperative (EKPC) Zone, which integrated into PJM on June 1, 2013, was included in RPM for the first time in the 2016/2017 RPM Base Residual Auction.

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.[29] The rule requires compliance by April 16, 2015 with the possibility of one year extensions being granted to individual generation owners.[30]

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.[31] The rule implements performance standards on May 1, 2015, just prior to the commencement of the 2015/2016 Delivery Year.

Prior to the 2016/2017 RPM Base Residual Auction, the PJM Markets and Reliability (MRC) approved DR plan enhancements, which were meant to standardize the information requirements for offering planned DR into BRAs, increase the likelihood that offers were based on physical assets and reduce the level of speculative offers. A

28 Letter Order issued in Docket No. ER13-149 (November 28, 2012).

29 *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).

30 *Id*. at 9465.

31 N.J.A.C. § 7:27–19.

group of Curtailment Service Providers (CSPs) filed a complaint with FERC on April 3, 2013, and FERC granted the complaint on April 19, 2013.[32] Although not in place for the 2016/2017 BRA, the discussion and approval of the DR plan enhancements in the PJM stakeholder process could have resulted in a reduction in speculative DR offered compared to the prior BRA.

## MMU Methodology

The MMU reviewed the following inputs to and results of the 2016/2017 RPM Base Residual Auction:[33]

- **Offer Cap.** Verified that the avoidable costs, opportunity costs and net revenues used to calculate offer caps were reasonable and properly documented;

- **Net Revenues.** Calculated actual unit-specific net revenue from PJM energy and ancillary service markets for each PJM Generation Capacity Resource for the period from 2010 through 2012;

- **Minimum Offer Price Rule (MOPR).** Reviewed unit specific, competitive entry, and self supply requests for exceptions to the MOPR;[34]

- **Mitigation 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;

---

32 See 143 FERC ¶ 61,061 (2013).

33 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 Demand Resource Factor and 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 2016/2017 RPM Base Residual Auction.

34 As FERC responded to PJM's filing for MOPR revisions in Dockets Nos. ER13-535-000 and ER13-535-001 on May 2, 2013, which was after the MOPR related deadlines, MOPR exception requests for the 2016/2017 RPM Base Residual Auction were reviewed under both the effective and proposed MOPR at that time.

- **Excused Resources.** Reviewed exceptions to the RPM 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, 2012 or reviewed requests for alternate maximum EFORds;

- **Clearing Prices.** Verified that the auction clearing prices were accurate, based on submitted offers,[35] the Variable Resource Requirement (VRR) curves, and the Minimum Resource Requirements;

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

## Market Structure Tests

As shown in Table 2, all participants in the RTO, MAAC, PSEG and ATSI RPM markets failed the TPS test.[36] The result was that offer caps were applied to all sell offers for Existing Generation Capacity Resources when the Capacity Market Seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would have increased the market clearing price. Market power mitigation was applied to 50 Generation Capacity Resources, including 4,587.6 MW in the 2016/2017 RPM Base Residual Auction. All other offers were competitive.

In applying the 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 cost-based clearing price.[37] 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 cost-based clearing price for the constrained LDA. The relevant demand consists of the incremental MW needed in the LDA to relieve the constraint.

---

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

36 See the *2012 State of the Market Report for PJM* (March 14, 2013), Volume II, Section 2, "Energy Market," and the MMU *Technical Reference for PJM Markets*, at "Three Pivotal Supplier Test" for a more detailed discussion of market structure tests.

37 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 2 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.[38] MAAC/EMAAC/SWMAAC/DPL South/Pepco are presented together because EMAAC, SWMAAC, DPL South, and Pepco were modeled but were not constrained LDAs in this auction.

**Table 2 RSI Results: 2016/2017 RPM Base Residual Auction[39]**

| | $RSI_{1\ 1.05}$ | $RSI_3$ | Total Participants | Failed $RSI_3$ Participants |
|---|---|---|---|---|
| RTO | 0.78 | 0.59 | 110 | 110 |
| MAAC/EMAAC/SWMAAC/DPL South/Pepco | 0.56 | 0.38 | 6 | 6 |
| PSEG/PSEG North | 0.00 | 0.00 | 1 | 1 |
| ATSI/ATSI Cleveland | 0.00 | 0.00 | 1 | 1 |

## *Offer Caps*

The defined Generation Capacity Resource owners were required to submit ACR or opportunity cost data to the MMU by 120 days prior to the 2016/2017 RPM Base Residual Auction.[40] Market power mitigation measures are applied to Existing Generation Capacity Resources such that the sell offer is set equal to the defined offer

38 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.

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

40 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 (November 28, 2012).

cap when the Capacity Market Seller fails the market structure test for the auction, the submitted sell offer exceeds the defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price.[41] For RPM Base Residual Auctions, offer caps are defined as avoidable costs less PJM market revenues or opportunity costs.

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.[42] 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. Capacity resource owners could provide ACR data by providing their own unit-specific data or by selecting the default ACR values. The specific components of avoidable costs are defined in the PJM Tariff.[43]

The opportunity cost option allows Capacity Market Sellers to input a documented price available in a market external to PJM, subject to export limits. If the relevant RPM market clears above the opportunity cost, the Generation Capacity Resource is sold in the RPM market. If the opportunity cost is greater than the clearing price and the Generation Capacity Resource does not clear in the RPM market, it is available to sell in the external market.

The MMU calculated offer caps for 638 generation resources, of which 491 were based on the technology specific default (proxy) ACR values.[44] No generation resources elected to use the retirement ACR in the 2016/2017 BRA. The default ACR values for the 2016/2017 Delivery Year were calculated by applying the applicable annual rate of change in the Handy-Whitman Index value to update the base values through 2012/2013 for which data were available and applying the most recent ten year annual average rate of change in the Handy-Whitman Index to recalculate the default ACR values for

41 OATT Attachment DD § 6.5.

42 OATT Attachment DD § 6.8 (b).

43 OATT Attachment DD § 6.8 (a).

44 Four generation resources had both ACR based and opportunity cost based offer caps calculated, and 25 generation resources had uncapped planned uprates along with ACR based offer caps calculated for the existing portion.

2013/2014 through 2015/2016 prior to estimating the default ACR values for the 2016/2017 Delivery Year.[45]

Unit-specific offer caps were calculated for 139 generation resources (11.6 percent) including 138 generation resources (11.5 percent) with an Avoidable Project Investment Recovery Rate (APIR) component and one generation resource (0.1 percent) without an APIR component. Owners submitted unit-specific cost data, the MMU calculated net revenue data for these units, and the MMU calculated the unit-specific offer caps based on that data. Of the 1,199 generation resources offered, 31 Planned Generation Capacity Resources had uncapped offers, 15 generation resources had planned uprates with uncapped offers plus default ACR based offer caps calculated for the existing portion of the units, 11 generation resources had planned uprates with uncapped offers plus price taker status for the existing portion of the units, while the remaining 519 generation resources were price takers.[46]

As shown in Table 4, the weighted average gross ACR for units with APIR ($352.84 per MW-day) and the weighted-average offer caps, net of net revenues, for units with APIR ($180.23 per MW-day) decreased from the 2015/2016 BRA values of $401.95 per MW-day and $246.63 per MW-day, due primarily to lower weighted average gross ACRs for combined cycle, combustion turbine, oil and gas steam units, and subcritical/supercritical coal units.

The APIR component added an average of $191.19 per MW-day to the ACR value of the APIR units compared to $238.79 per MW-day in the 2015/2016 BRA.[47] [48] The highest APIR for a technology ($236.99 per MW-day) was for subcritical/supercritical coal units.

45 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. See 142 FERC ¶ 61,092 (2013).

46 Planned Generation Capacity Resources are subject to different market power mitigation rules than Existing Generation Capacity Resources. For RPM rules on mitigation, see OATT Attachment DD § 6.5 (a) (ii). For the definition of Planned Generation Capacity Resource, see "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region", Section 1.70.

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

48 The 138 resources which had an APIR component submitted $1.8 billion for capital projects associated with 27,384.2 MW of UCAP.

The maximum APIR effect ($773.08 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

Offer caps for units without an APIR component, including units for which the default value was selected, decreased from $17.86 per MW-day to $16.07 per MW-day due primarily to lower weighted-average gross ACRs and higher weighted-average net revenues for units without an APIR component.[49]

**Table 3 ACR statistics: 2016/2017 RPM Base Residual Auction**

| Offer Cap/Mitigation Type | Number of Generation Resources Offered | Percent of Generation Resources Offered |
|---|---|---|
| Default ACR | 471 | 39.3% |
| ACR data input (APIR) | 138 | 11.5% |
| ACR data input (non-APIR) | 1 | 0.1% |
| Opportunity cost | 8 | 0.7% |
| Default ACR and opportunity cost | 5 | 0.4% |
| Uncapped planned uprates and default ACR | 15 | 1.3% |
| Uncapped planned uprates and opportunity cost | 0 | 0.0% |
| Uncapped planned uprates and price taker | 11 | 0.9% |
| Uncapped planned generation resources | 31 | 2.6% |
| Existing generation resources as price takers | 519 | 43.3% |
| Total Generation Capacity Resources offered | 1,199 | 100.0% |

[49] The default ACR values include an average APIR of $1.39 per MW-day compared to $1.48 per MW-day in the 2015/2016 BRA.

**Table 4 APIR statistics: 2016/2017 RPM Base Residual Auction**[50] [51]

| | Weighted-Average ($ per MW-day UCAP) | | | | | |
|---|---|---|---|---|---|---|
| | Combined Cycle | Combustion Turbine | Oil or Gas Steam | Subcritical/ Supercritical Coal | Other | Total |
| Non-APIR units | | | | | | |
| ACR | $42.11 | $33.46 | $78.32 | $215.57 | $75.69 | $102.23 |
| Net revenues | $194.19 | $56.23 | $42.33 | $208.04 | $228.59 | $150.24 |
| Offer caps | $4.80 | $7.64 | $36.43 | $29.03 | $4.63 | $16.07 |
| | | | | | | |
| APIR units | | | | | | |
| ACR | $52.48 | $93.23 | $188.80 | $432.72 | $53.20 | $352.84 |
| Net revenues | $72.50 | $17.49 | $16.68 | $222.52 | $62.15 | $177.14 |
| Offer caps | $13.92 | $79.12 | $167.29 | $213.88 | $5.91 | $180.23 |
| APIR | $14.45 | $57.71 | $64.90 | $236.99 | $23.01 | $191.19 |
| | | | | | | |
| Maximum APIR effect | | | | | | $773.08 |

## *Generation Capacity Resource Changes*

As shown in Table 3, offers were submitted for 1,199 generation resources in the 2016/2017 RPM Base Residual Auction compared to 1,168 generation resources offered in the 2015/2016 RPM Base Residual Auction, or a net increase of 31 generation resources. This was a result of 99 additional generation resources offered offset by 68 fewer generation resources offered.

The 99 additional generation resources offered consisted of 36 new resources (4,900.8 MW), 29 additional resources imported (3,026.3 MW), 18 East Kentucky Power Cooperative (EKPC) integration resources not offered in the 2015/2016 BRA (2,537.3 MW), nine resources that were excused and not offered in the 2015/2016 BRA (1,033.9 MW), three repowered resources (920.2 MW), two resources that were previously

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

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

entirely FRR committed (168.3 MW), one reactivated resource (17.6 MW), and one additional resource resulting from the disaggregation of an RPM resource.[52]

The 36 new Generation Capacity Resources consisted of 11 diesel resources (36.1 MW), nine solar resources (32.1 MW), eight combined cycle resources (4,597.2 MW), five wind resources (54.3 MW), two CT resources (159.3 MW), and one steam unit (21.8 MW). In addition, there were new generation resources that were not offered in to the auction because they were either exported or entirely committed to FRR for the 2016/2017 Delivery Year: one wind resource (12.8 MW) and one diesel resource (5.3 MW).

The 68 fewer generation resources offered consisted of 33 additional resources excused from offering (1,706.0 MW), 28 deactivated resources (1,389.6 MW), three fewer resources resulting from aggregation of RPM resources, two additional resources committed fully to FRR (28.7 MW), and two Planned Generation Capacity Resources not offered (934.8 MW). In addition, there were the following retirements of resources that were either exported, excused, or committed to an FRR capacity plan in the 2015/2016 BRA: 25 steam units (2,207.1 MW) and 13 CT resources (245.0 MW). Table 5 shows Generation Capacity Resources for which deactivation requests have been submitted which affected supply between the 2015/2016 BRA and the 2016/2017 BRA.

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

**Table 5 Generation Capacity Resource Deactivations**

| Resource Name | LDA | ICAP (MW) | Date Deactivation Notice Submitted | Projected or Actual Deactivation Date | Resource Name | LDA | ICAP (MW) | Date Deactivation Notice Submitted | Projected or Actual Deactivation Date |
|---|---|---|---|---|---|---|---|---|---|
| BRUNOT ISLAND CT1B | RTO | 15.0 | 20-Apr-11 | 01-Jun-11 | EDISON 31 | PSEG | 42.0 | 11-Jan-13 | 01-Jun-15 |
| BRUNOT ISLAND CT1C | RTO | 15.0 | 20-Apr-11 | 01-Jun-11 | EDISON 32 | PSEG | 42.0 | 11-Jan-13 | 01-Jun-15 |
| SEWAREN 1 | PSEG | 104.0 | 21-Mar-12 | 01-Jun-15 | EDISON 33 | PSEG | 42.0 | 11-Jan-13 | 01-Jun-15 |
| SEWAREN 2 | PSEG | 118.0 | 21-Mar-12 | 01-Jun-15 | EDISON 34 | PSEG | 42.0 | 11-Jan-13 | 01-Jun-15 |
| SEWAREN 3 | PSEG | 107.0 | 21-Mar-12 | 01-Jun-15 | ESSEX 101 | PSEG North | 42.0 | 11-Jan-13 | 01-Jun-15 |
| SEWAREN 4 | PSEG | 123.6 | 21-Mar-12 | 01-Jun-15 | ESSEX 102 | PSEG North | 42.0 | 11-Jan-13 | 01-Jun-15 |
| HUTCHINGS 4 | RTO | 61.9 | 28-Jun-12 | 01-Jun-13 | ESSEX 103 | PSEG North | 42.0 | 11-Jan-13 | 01-Jun-15 |
| BURLINGTON 91 | PSEG | 46.0 | 10-Sep-12 | 01-Jun-14 | ESSEX 104 | PSEG North | 42.0 | 11-Jan-13 | 01-Jun-15 |
| BURLINGTON 92 | PSEG | 46.0 | 10-Sep-12 | 01-Jun-14 | ESSEX 111 | PSEG North | 46.0 | 11-Jan-13 | 01-Jun-15 |
| BURLINGTON 93 | PSEG | 46.0 | 10-Sep-12 | 01-Jun-14 | ESSEX 112 | PSEG North | 46.0 | 11-Jan-13 | 01-Jun-15 |
| BURLINGTON 94 | PSEG | 46.0 | 10-Sep-12 | 01-Jun-14 | ESSEX 113 | PSEG North | 46.0 | 11-Jan-13 | 01-Jun-15 |
| CHESAPEAKE 3 DOM | RTO | 147.0 | 11-Oct-12 | 31-Dec-14 | ESSEX 114 | PSEG North | 46.0 | 11-Jan-13 | 01-Jun-15 |
| CHESAPEAKE 4 DOM | RTO | 207.0 | 11-Oct-12 | 31-Dec-14 | HUTCHINGS 3 | RTO | 59.0 | 11-Jan-13 | 01-Jun-15 |
| YORKTOWN 2 | RTO | 164.0 | 11-Oct-12 | 31-Dec-14 | HUTCHINGS 5 | RTO | 58.5 | 11-Jan-13 | 01-Jun-15 |
| RIVERSIDE CT 6 | SWMAAC | 115.0 | 31-Oct-12 | 01-Jun-14 | HUTCHINGS 6 | RTO | 57.0 | 11-Jan-13 | 01-Jun-15 |
| SCHUYLKILL 1 | EMAAC | 166.0 | 31-Oct-12 | 01-Jan-13 | MIDDLE 1 CT | EMAAC | 19.4 | 11-Jan-13 | 31-May-15 |
| ESSEX 121 | PSEG North | 46.0 | 20-Nov-12 | 31-May-15 | MIDDLE 2 CT | EMAAC | 20.0 | 11-Jan-13 | 31-May-15 |
| ESSEX 122 | PSEG North | 46.0 | 20-Nov-12 | 31-May-15 | MIDDLE 3 CT | EMAAC | 35.9 | 11-Jan-13 | 31-May-15 |
| ESSEX 123 | PSEG North | 46.0 | 20-Nov-12 | 31-May-15 | GILBERT 8 | EMAAC | 90.0 | 22-Jan-13 | 01-May-15 |
| ESSEX 124 | PSEG North | 46.0 | 20-Nov-12 | 31-May-15 | GILBERT C-1 | EMAAC | 23.0 | 22-Jan-13 | 01-May-15 |
| B.L. ENGLAND EMER DIESEL | EMAAC | 8.0 | 07-Jan-13 | 01-Oct-15 | GILBERT C-2 | EMAAC | 25.0 | 22-Jan-13 | 01-May-15 |
| BURLINGTON 111 | PSEG | 46.0 | 11-Jan-13 | 01-Jun-15 | GILBERT C-3 | EMAAC | 25.0 | 22-Jan-13 | 01-May-15 |
| BURLINGTON 112 | PSEG | 46.0 | 11-Jan-13 | 01-Jun-15 | GILBERT C-4 | EMAAC | 25.0 | 22-Jan-13 | 01-May-15 |
| BURLINGTON 113 | PSEG | 46.0 | 11-Jan-13 | 01-Jun-15 | WERNER C-1 | EMAAC | 53.0 | 22-Jan-13 | 01-May-15 |
| BURLINGTON 114 | PSEG | 46.0 | 11-Jan-13 | 01-Jun-15 | WERNER C-2 | EMAAC | 53.0 | 22-Jan-13 | 01-May-15 |
| EDISON 11 | PSEG | 42.0 | 11-Jan-13 | 01-Jun-15 | WERNER C-3 | EMAAC | 53.0 | 22-Jan-13 | 01-May-15 |
| EDISON 12 | PSEG | 42.0 | 11-Jan-13 | 01-Jun-15 | WERNER C-4 | EMAAC | 53.0 | 22-Jan-13 | 01-May-15 |
| EDISON 13 | PSEG | 42.0 | 11-Jan-13 | 01-Jun-15 | B.L. ENGLAND 1 | EMAAC | 113.0 | 27-Mar-13 | 01-May-14 |
| EDISON 14 | PSEG | 42.0 | 11-Jan-13 | 01-Jun-15 | | | | | |
| EDISON 21 | PSEG | 42.0 | 11-Jan-13 | 01-Jun-15 | | | | | |
| EDISON 22 | PSEG | 42.0 | 11-Jan-13 | 01-Jun-15 | | | | | |
| EDISON 23 | PSEG | 42.0 | 11-Jan-13 | 01-Jun-15 | | | | | |
| EDISON 24 | PSEG | 42.0 | 11-Jan-13 | 01-Jun-15 | | | | | |

## *RTO Market Results*

### Total Offers

Table 6 shows total RTO offer data for the 2016/2017 RPM Base Residual Auction. All MW values stated in the RTO section include all nested LDAs.[53] [54] As shown in Table 8,

53 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.

54 Maps of the LDAs can be found in the *2012 State of the Market Report for PJM*, Appendix A, "PJM Geography."

total internal RTO unforced capacity (UCAP) decreased 3,709.2 MW (1.8 percent) from 204,557.3 MW in the 2015/2016 RPM BRA to 200,848.1 MW.[55]

When comparing UCAP MW levels from one auction to another, two variables, capacity modifications and EFORd changes, need to be considered. The net internal capacity change attributable to capacity modifications can be determined by holding the EFORd level constant at the prior auction's level. The EFORd effect is the measure of the net internal capacity change attributable to EFORd changes and not capacity modifications. The 3,709.2 MW increase in internal capacity was a result of net generation capacity modifications (cap mods) (2,895.9 MW), net DR capacity changes (-10,690.1 MW), net EE modifications (262.5 MW), the EFORd effect due to lower sell offer EFORds (1,039.0 MW), the DR and EE effect due to a higher Load Management UCAP conversion factor (47.8 MW), and the integration of the EKPC Zone (2,735.7 MW).[56]

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 2016/2017 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.[57] 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

[55] The maximum capacity within a coupled Demand Resource group was included in the internal capacity values and capacity changes reported.

[56] The UCAP value of a load management product is equal to the ICAP value multiplied by the Demand Resource (DR) Factor and the Forecast Pool Requirement (FPR). For the 2015/2016 BRA, this conversion factor was 0.955*1.0859 = 1.0370. For the 2016/2017 BRA, this factor was 0.955*1.0902 = 1.0411. The DR Factor is 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," Revision 05 (February 1, 2013), p. 13-15.

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

in question.[58] Otherwise the owner must take an outage, as appropriate, if the owner cannot provide energy consistent with the ICAP of the unit. Capacity, DR plan changes, and EE modifications 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.

After accounting for FRR committed resources and for imports, total RPM capacity was 194,324.1 MW compared to 194,126.5 MW in the 2015/2016 RPM Base Residual Auction.[59] FRR volumes decreased by 360.8 MW, and imports increased by 3,546.0 MW. Of the 7,491.5 MW of imports, 447.8 MW were committed to an FRR capacity plan and 7,493.7 MW were offered in the auction, of which all 7,482.7 MW cleared. Of the cleared imports, 4,723.1 MW (63.1 percent) were from MISO. RPM capacity was reduced by exports of 1,211.6 MW, a decrease of 2.6 MW from the 2015/2016 RPM Base Residual Auction. Of total exports, 674.0 MW (55.6 percent) were to the NYISO and 537.6 MW (44.4 percent) were to MISO.

In addition, RPM capacity was reduced by 1,451.1 MW of Planned Generation Capacity Resources which were not subject to the RPM must offer requirement and by 3,620.6 MW which were excused from the RPM must offer requirement, a decrease of 3,659.9 MW from the 2015/2016 RPM Base Residual Auction. The excused Existing Generation Capacity Resources were the result of plans for retirement (3,555.3 MW), significant physical operational restrictions (15.8 MW), and 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 (49.5 MW).[60] Subtracting 2,225.4 MW of FRR optional volumes not offered, an increase of 2,066.5 MW from the 2015/2016 RPM Base Residual Auction, and 1,435.4 MW of DR and EE not offered, resulted in 184,380.0 MW that were available to be offered in the RPM Auction, an increase of 5,792.3 MW from

---

58 PJM. "Manual 21: Rules and Procedures for Determination of Generating Capability," Revision 09 (May 1, 2010), p. 11. The manual states "the end of the next Delivery Year."

59 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.

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

the 2015/2016 RPM Base Residual Auction.[61] [62] After accounting for the above, 0.0 MW were not offered in the RPM Auction.

Offered MW increased 5,792.3 MW from 178,587.7 MW to 184,380.0 MW, while the overall RTO Reliability Requirement adjusted for FRR obligations, from which the demand curve is developed, increased 3,350.1 MW from 162,777.4 MW to 166,127.5 MW.[63] 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.[64] The 3,350.1 MW increase in the RTO Reliability Requirement adjusted for FRR obligations from the 2015/2016 RPM Base Residual Auction was a result of a 202.0 MW decrease in the FRR obligation and a 3,148.1 MW increase in the RTO Reliability Requirement not adjusted for FRR, shifting the RTO market demand curve to the right. The forecast peak load expressed in terms of installed capacity increased 2,244.0 MW from the 2015/2016 RPM Base Residual Auction to 165,412.0 MW. The 3,148.1 MW increase in the RTO Reliability Requirement was a result of a 2,436.8 MW increase in the forecast peak load in UCAP terms holding the FPR constant at the 2015/2016 level and a 711.3 MW increase attributable to the change in the FPR.

## Minimum DR Requirements

PJM's auction clearing mechanism will result in a higher price for Extended Summer Resources if the MW of Extended Summer Resources that would otherwise clear the auction are less than the Minimum Extended Summer Resource Requirement that PJM requires for reliability. In that case the auction clearing mechanism will select Extended Summer Resources that are more expensive than the clearing price that would otherwise

---

[61] FRR entities are allowed to offer in the RPM Auction excess volumes above their FRR quantities, subject to a sales cap amount. The 2,225.4 MW are a combination of excess volumes included in the sales cap amount which were not offered in the auction and volumes above the sales cap amount which were not permitted to offer in the auction.

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

[63] The maximum capacity within a coupled Demand Resource group was included in the offered capacity values reported.

[64] PJM. "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 4.1.<http://www.pjm.com/~/media/documents/agreements/raa.ashx>

result in order to procure the defined minimum resource requirements for the Extended Summer product. This is referred as the Minimum Extended Summer Resource Requirement being a binding constraint. Similarly, PJM's auction clearing mechanism will result in a higher price for Annual Resources if the MW of Annual Resources that would otherwise clear the auction are less than the Minimum Annual Resource Requirement that PJM requires for reliability. In that case the auction clearing mechanism will select Annual Resources that are more expensive than the clearing price that would otherwise result in order to procure the defined minimum resource requirements for the Annual Resources. This is referred as the Minimum Annual Resource Requirement being a binding constraint.

The Minimum Extended Summer Resource Requirement and the Minimum Annual Resource Requirement were not binding constraints for the RTO in the 2016/2017 BRA. As shown in Figure 1, the resource clearing price for Limited, Extended Summer, and Annual Resources for the RTO was $59.37 per MW-day.

## 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.[65] As shown in Table 6, the preliminary Net Load Price is $59.37 per MW-day in the RTO.

As shown in Table 6, the cleared and make-whole MW of 169,159.7 for the entire RTO, which represented a reserve margin of 21.5 percent, resulted in net excess of 7,185.4 MW over the reliability requirement of 166,127.5 MW (Installed Reserve Margin (IRM) of 15.6 percent).[66, 67] Net excess increased 1,329.5 MW from the net excess of 5,855.9 MW in the 2015/2016 RPM Base Residual Auction. As shown in Figure 1, the downward sloping VRR demand curve resulted in a clearing price for Limited, Extended Summer, and Annual Resources of $59.37 per MW-day.

---

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

66 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 Delivery Year and beyond, net excess under RPM is calculated as cleared capacity plus make-whole MW less the reliability requirement plus the Short-Term Resource Procurement Target.

67 The IRM increased from 15.4 percent in the 2015/2016 RPM Base Residual Auction to 15.6 percent in the 2016/2017 RPM Base Residual Auction.

If the market clears on a nonflexible supply segment, a sell offer that specifies a minimum block MW value greater than zero, the Capacity Market Seller will be assigned make-whole MW equal to the difference between the sell offer minimum block MW and the sell offer cleared MW quantity if that solution to the market clearing minimizes the cost of satisfying the reliability requirements across the PJM region.[68] 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.[69] The market results in the 2016/2017 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.[70] [71] In the two subsequent BRAs, if a qualifying resource does not clear, the process specified in the Tariff is triggered, and the resource is awarded a make-whole payment.[72] The market results in the 2016/2017 BRA did not include make-whole MW or payments related to NEPA or Multi-Year Pricing Option.

Table 9 shows cleared MW by zone and fuel source. Of the 168,716.0 MW offered for generation resources, 155,634.3 MW cleared (92.2 percent). Of the 169,159.7 cleared MW in the entire RTO, 25,551.2 MW (15.1 percent) cleared in Dominion, followed by 25,346.3 MW in ComEd (15.0 percent) and 15,576.0 MW (9.2 percent) in AEP. Of the 155,634.3 cleared MW for generation resources in the entire RTO, 60,207.4 MW (38.7 percent) were gas resources, followed by 46,681.1 MW (30.0 percent) from coal resources and 30,801.1 MW (19.8 percent) from nuclear resources.

The 15,220.3 MW uncleared MW in the entire RTO were the result of offer prices which exceeded the clearing prices. Of the 15,220.3 uncleared MW in the entire RTO, 39.5 MW were EE offers, 2,099.1 MW were DR offers, and the remaining 13,081.7 MW were generation offers. Table 10 presents details on the generation offers that did not clear. Of the 13,081.7 MW of uncleared generation offers, 7,448.0 MW (56.9 percent) were for generation resources greater than 40 years old, and 5,633.7 MW (43.1 percent) were for

---

68 OATT Attachment DD § 5.14 (b).

69 OATT Attachment DD § 5.12 (a).

70 OATT Attachment DD § 5.14 (c) (2).

71 OATT Attachment DD § 6.8 (a).

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

generation resources less than or equal to 40 years old. Of the 13,081.7 MW of uncleared offers for generation resources, 10,545.1 MW were offers for resources including costs associated with environmental regulation compliance that were not previously included in APIR.

Table 11 shows the auction results for the prior two delivery years for the generation resources that did not clear some or all MW in the 2016/2017 BRA. Of the 56 generation resources that did not clear 13,081.7 MW in the 2016/2017 BRA, 15 of those generation resources did not clear 5,301.5 MW in RPM Auctions for the 2015/2016 Delivery Year. Of those 15 generation resources that did not clear MW in RPM Auctions for the 2016/2017 and 2015/2016 Delivery Years, three of those generation resources did not clear 272.0 MW in RPM Auctions for the 2014/2015 Delivery Year. Thus, 5,301.5 MW of capacity did not clear in two sequential auctions, but only 272.0 MW did not clear in three sequential auctions.

## Constraints in RPM Markets: CETO/CETL

Since the ability to import energy and capacity in LDAs may be limited by the existing transmission capability, a load deliverability analysis is conducted for each LDA.[73] The first step in this process is to determine the transmission import requirement in to an LDA, called the Capacity Emergency Transfer Objective (CETO). This value, expressed in unforced megawatts, is the transmission import capability required for each LDA to meet the area reliability criterion of loss of load expectation of one occurrence in 25 years when the LDA is experiencing a localized capacity emergency.

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

If CETL is less than CETO, transmission upgrades are planned under the Regional Transmission Expansion Planning (RTEP) Process. However, if transmission upgrades cannot be built prior to a delivery year to increase the CETL value, locational constraints could result under RPM, causing locational price differences.[74]

---

[73] PJM. "Manual 14B: PJM Region Transmission Planning Process, Attachment C: PJM Deliverability Testing Methods," Revision 24 (June 5, 2013), p. 52. Manual 14B indicates that all "electrically cohesive load areas" are tested.

[74] PJM. "Manual 18: PJM Capacity Market," Revision 19 (June 1, 2013), p. 10.

Under the Tariff, PJM determines, in advance of each BRA, whether defined Locational Deliverability Areas (LDAs) will be modeled in the auction. Effective with the 2012/2013 Delivery Year, an LDA 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 the above three tests.[75] In addition, PJM may establish a constrained LDA even if it does not qualify under the above tests if PJM finds that "such is required to achieve an acceptable level of reliability."[76] 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.

Table 12 shows the CETL and CETO values used in the 2016/2017 study compared to the 2015/2016 values. The increase in CETL for the ATSI LDA is mainly due to several RTEP projects developed since the 2015/2016 BRA study to alleviate reliability concerns.[77] The ATSI Cleveland LDA was modeled for the first time in the 2016/2017 BRA, because it is a sub-region of the ATSI LDA and shares the same reliability concerns associated with significant generation retirements.

## 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 on total market revenues depends on the relative sizes of the various markets as well as the shapes of the supply and demand curves in the various markets.

---

[75] 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.

[76] OATT Attachment DD § 5.10 (a) (ii).

[77] See PJM "2016/2017 RPM Base Residual Auction Planning Period Parameters" <http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2016-2017-planning-period-parameters-report.ashx> (February 1, 2013).

There were three locationally binding constraints in the 2016/2017 BRA which resulted in demand clearing in locationally constrained LDAs which did not clear in the RTO market. 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 graphs 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.

## Composition of the Steeply Sloped Portion of the Supply Curve

Table 13 shows the composition of the offers on the steeply sloped portion of the total RTO supply curve from $35.00 per MW-day up to and including the highest offer of $722.64 per MW-day. Offers for DR and EE resources were 19.7 percent of the offers greater than $35.00 per MW-day. Offers for subcritical/supercritical coal units, combined cycles, oil or gas steam, and combustion turbines made up 80.2 percent of the offers greater than $35.00 per MW-day.

## Short-Term Resource Procurement Target (2.5 Percent Shift in Demand Curve)

Effective for the 2012/2013 Delivery Year, ILR was eliminated. Prior to this, PJM subtracted the ILR forecast from the reliability requirement. Under the current rules, application of the Short-Term Resource Procurement Target means that 2.5 percent of the reliability requirement is removed from the demand curve. The stated rationale is that this provides for short lead time resource procurement in incremental auctions for the given delivery year. For the 2016/2017 BRA, the 2.5 percent reduction resulted in the removal of 4,153.2 MW from the RTO demand curve. For comparison purposes, in the 2011/2012 BRA, removal of the ILR forecast from the reliability requirement resulted in a reduction in demand of 1,593.8 MW, or 1.2 percent of the reliability requirement of 130,658.7 MW.

Table 14 shows the results if the demand curves had not been reduced by the Short-Term Resource Procurement Target and everything else had remained the same. All binding constraints would have remained the same, except that the ATSI Minimum Extended Summer Resource Requirement would not have been binding. The RTO clearing price for Limited, Extended Summer, and Annual Resources would have increased to $85.71 per MW-day, and the clearing quantity would have increased to

172,886.9 MW. The MAAC clearing price for Limited, Extended Summer, and Annual Resources would have increased to $130.00 per MW-day, and the clearing quantity would have increased to 68,088.6 MW. The ATSI clearing price for Limited, Extended Summer, and Annual Resources would have increased to $122.97 per MW-day, and the clearing quantity would have increased to 8,979.2 MW.

The conclusion is that the removal of 2.5 percent of demand significantly reduced the clearing prices and quantities for all the RPM LDA markets. The clearing quantities of Annual Resources, including generation and Annual DR, were reduced as a result of the 2.5 percent demand reduction.

Based on actual auction clearing prices and quantities and make-whole MW, total RPM market revenues for the 2016/2017 RPM Base Residual Auction were $5,513,237,849. If the VRR curves had not been reduced by the Short-Term Resource Procurement Target, total RPM market revenues for the 2016/2017 RPM Base Residual Auction would have been $6,894,277,704, an increase of $1,381,039,855, or 25 percent, compared to the actual results. The use of the Short-Term Resource Procurement Target resulted in a 20 percent reduction in RPM revenues for the 2016/2017 Base Residual Auction.

The MMU recommends that the use of the 2.5 percent demand adjustment be terminated immediately.[78] The 2.5 percent demand reduction is a barrier to entry in the capacity market for both new generation capacity and new DR capacity. The logic of reducing demand in a market design that looks three years forward, to permit other resources to clear in incremental auctions, is not supportable and has no basis in economics. There are tradeoffs in using a one year forward or a three year forward design, but the design should be implemented on a consistent basis. Removing a portion of demand affects prices at the margin, which is where the critical signal to the market is determined. The proposal to eliminate the Short Term Resource Procurement Target is not counter to the interests of DR. Most DR clears in the BRA where prices have been substantially higher than in the incremental auctions. Price suppression is a barrier to the entry of new Demand Resources in exactly the same way that it is a barrier to the entry of new generation resources. In the 2016/2017 BRA, the result of reducing demand by 2.5 percent was to reduce prices in the eastern part of PJM and to reduce the quantity of capacity purchased in the eastern part of PJM. The result was also to significantly reduce the clearing price for the RTO market and reducing total payments to capacity by a significant amount. The 2.5 percent offset was added to permit DR to clear in incremental auctions. It was not added to counter persistent forecast errors. Forecast

---

78 See also the *Protest of the Independent Market Monitor for PJM*, Docket No. ER12-513 (December 22, 2011).

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 would result in biasing the overall market results in favor of transmission rather than generation solutions to reliability issues.

## Demand Side Resources in RPM

There are two categories of demand side products included in the RPM market design for the 2016/2017 BRA:[79] [80]

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

- **Energy Efficiency (EE) Resources.** Load resources that are offered in an RPM Auction as capacity and receive the relevant LDA or RTO resource clearing price. An EE Resource is a project designed to achieve a continuous (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.[81] 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.[82]

---

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

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

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

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

Effective with the 2014/2015 Delivery Year, there are three types of Demand Resource products incorporated in the RPM market design:[83] [84]

- **Annual DR.** 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 at least ten hours 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.

- **Extended Summer DR.** Demand Resource that is required to be available on any day from June through October and the following May in the relevant delivery year for an unlimited number of interruptions. Extended Summer DR is required to be capable of maintaining each interruption for at least ten hours 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 at least six hours during the hours of 12:00 p.m. to 8:00 p.m. EPT.

Table 15 shows offered and cleared capacity from Demand Resources and Energy Efficiency Resources in the 2016/2017 RPM Base Residual Auction compared to the 2015/2016 RPM Base Residual Auction. Offers for DR decreased from 19,956.3 MW in the 2015/2016 BRA to 14,507.2 MW in the 2016/2017 BRA, a decrease of 5,449.1 or 27.3 percent.

Table 16 shows offered and cleared MW for Demand Resources by LDA and offer/product type in the 2016/2017 RPM Base Residual Auction. Of the 5,911.9 MW of non-coupled DR offers, 4,387.9 MW were for the Limited DR product. Of the possible DR coupling scenarios, the most frequently used was the Annual, Extended Summer, and Limited DR coupling group, with from 3,000 to 6,000 MW of DR offered this way. The fact that most offers were coupled provides evidence that suppliers are willing to offer a DR product that is almost comparable to generation resources in that it does not have such significant limitations on availability and that they will offer it at a higher price, reflecting the fact that such a product has higher costs.

---

83 134 FERC ¶ 61,066 (2011).

84 "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Article 1. <http://www.pjm.com/~/media/documents/agreements/raa.ashx>

Table 17 shows the weighted average prices for DR by LDA and offer/product type. As would be expected, given their relative values, for the coupled DR offers, the offers for Annual DR were greater than the offers for Extended Summer DR which were greater than the offers for Limited DR. In addition, the Capacity Market Seller must specify 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.

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.

## Impact of Inferior DR Product Types

Effective for the 2014/2015 Delivery Year, the RPM market design incorporates Annual and Extended Summer DR product types, in addition to the previously established Limited DR product type. Each DR product type is subject to a defined period of availability, maximum number of interruptions, and maximum duration of interruptions. The Limited DR and the Extended Summer DR product types are both inferior to Generation Capacity Resources, because the obligation to deliver associated with both product types is inferior to the obligation to deliver associated with Generation Capacity Resources. Generation resources are obligated to provide capacity every hour of the year if called.

Table 18 shows the results if only generation and Annual DR were offered in the 2016/2017 RPM Base Residual Auction, that is all offers for Extended Summer and Limited DR products, including those within coupled DR offers, were excluded from supply. All offers for Annual DR were included in supply, including those in non-coupled and coupled DR offers. The ATSI import limit would not have been binding. The RTO clearing price would have increased to $153.74 per MW-day, and the clearing quantity would have decreased to 167,254.1 MW. The MAAC clearing price would have increased to $175.00 per MW-day, and the clearing quantity would have decreased to 65,915.3. The PSEG clearing price would have increased to $277.10 per MW-day, and the clearing quantity would have decreased to 6,200.6 MW. The ATSI clearing price would have increased to $153.74 per MW-day, and the clearing quantity would have increased to 9,943.2 MW.

Based on actual auction clearing prices and quantities and make-whole MW, total RPM market revenues for the 2016/2017 RPM Base Residual Auction were $5,513,237,849. If only generation and Annual DR were offered in the 2016/2017 RPM Base Residual Auction, total RPM market revenues for the 2016/2017 RPM Base Residual Auction would have been $10,141,586,456, an increase of $4,628,348,607, or 84 percent, compared to the actual results. The inclusion of the Limited and Extended Summer DR products resulted in a 46 percent reduction in RPM revenues for the 2016/2017 Base Residual Auction.

While competition from demand side resources improves the functioning of the market, that is not the result if the demand side resources are not comparable to other capacity resources. The purpose of demand side participation in RPM is to provide a mechanism for end-use customers to avoid paying the capacity market clearing price in return for agreeing to not use capacity when it is needed by customers who have paid for capacity. The fact that customers providing Limited DR only have to agree to interrupt ten times per year for a maximum of six hours per interruption represents a flaw in the design of the program. There is no reason to believe that the customers who pay for capacity will need the capacity used by participating LM customers only ten times per year or a maximum of 60 hours per year or only during defined summer hours. In fact, it can be expected that the probability of needing that capacity will increase with the amount of MW that participating LM customers clear in the RPM Auctions. This limitation means that the demand side resources sold in the RPM Auctions are of less value than generation capacity. As a result, demand side resources could make lower offers than they would if they offered a comparable resource.

Given the significant impact of demand side resources on the RPM market outcomes, the MMU recommends that the definition of demand side resources be modified in order to ensure that such resources provide the same value in the capacity market as generation resources. Both the Limited and the Extended Summer DR products should be eliminated in order to ensure that the DR product has the same unlimited obligation to provide capacity year round as Generation Capacity Resources. As an example, if a single demand side site could not interrupt more than ten times per year, a Curtailment Service Provider (CSP) could bundle multiple demand sites to provide unlimited interruptions. The cost of providing bundled sites would be expected to be greater than a single site and the offer price of such resources would also be expected to be greater. Such a modification would help ensure that demand side resources contribute to the competitiveness of capacity markets rather than suppressing the price below the competitive level.

## Impact of Short-Term Resource Procurement Target and Inferior DR Product Types

Table 19 shows the results if the VRR curves had not been reduced by the Short-Term Resource Procurement Target and only generation and Annual DR were offered in the 2016/2017 RPM Base Residual Auction and everything else had remained the same. The ATSI import limit would not have been binding. The RTO clearing price would have increased to $243.46 per MW-day, and the clearing quantity would have increased to 169,457.4 MW. The MAAC clearing price would have increased to $266.49 per MW-day, and the clearing quantity would have slightly increased to 66,546.8 MW. The PSEG clearing price would have increased to $360.37 per MW-day, and the clearing quantity would have increased to 6,318.2 MW. The ATSI clearing price would have increased to $243.46 per MW-day, and the clearing quantity would have increased to 10,329.4 MW.

Based on actual auction clearing prices and quantities and make-whole MW, total RPM market revenues for the 2016/2017 RPM Base Residual Auction were $5,513,237,849. If the VRR curves had not been reduced by the Short-Term Resource Procurement Target and only generation and Annual DR were offered in the 2016/2017 RPM Base Residual Auction, total RPM market revenues for the 2016/2017 RPM Base Residual Auction would have been $15,834,365,769, an increase of $10,321,127,920, or 187 percent, compared to the actual results. The use of the Short-Term Resource Procurement Target together with the inclusion of the Limited and Extended Summer DR products resulted in a 65 percent reduction in RPM revenues for the 2016/2017 RPM Base Residual Auction.

## Impact of All DR

Table 20 shows the results if there were no offers for DR in the 2016/2017 RPM Base Residual Auction and everything else had remained the same. The RTO clearing price would have increased to $243.79 per MW-day, and the clearing quantity would have decreased to 165,296.7 MW. The MAAC clearing price would have increased to $279.22 per MW-day, and the clearing quantity would have decreased to 64,723.0 MW. The PSEG clearing price would have increased to $317.17 per MW-day, and the clearing quantity would have decreased to 6,132.9 MW. The ATSI import limit would not have been a binding constraint.

Based on actual auction clearing prices and quantities and make-whole MW, total RPM market revenues for the 2016/2017 RPM Base Residual Auction were $5,513,237,849. If there were no offers for DR in the 2016/2017 RPM Base Residual Auction, total RPM market revenues for the 2016/2017 RPM Base Residual Auction would have been $15,630,600,107, an increase of $10,117,362,259, or 184 percent, compared to the actual results. The inclusion of Demand Resources resulted in a 65 percent reduction in RPM revenues for the 2016/2017 Base Residual Auction.

These impacts combine the appropriate competitive impact of Annual DR with the price suppressing impacts of the Limited and Summer Unlimited DR products.

## Impact of Annual DR

The inclusion of sell offers for Annual DR alone 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 2016/2017 RPM Base Residual Auction were $5,513,237,849. If only generation and Annual DR were offered in the 2016/2017 RPM Base Residual Auction, total RPM market revenues for the 2016/2017 RPM Base Residual

Auction would have been $10,141,586,456. If there were no offers for DR in the 2016/2017 RPM Base Residual Auction, total RPM market revenues for the 2016/2017 RPM Base Residual Auction would have been $15,630,600,107, an increase of $5,489,013,652, or 54 percent, compared to the results with only Annual DR. The inclusion of sell offers for Annual DR alone resulted in a 35 percent reduction in RPM revenues for the 2016/2017 RPM Base Residual Auction compared to the revenues without any DR products.

This is the best measure of the competitive impact of DR on the RPM market. The Annual DR product definition is the only one consistent with being a capacity resource. Assuming that the DR meets appropriate measurement and verification standards and that the DR was offered with the intention of providing physical resources, competition from the Annual DR product resulted in a 35 percent reduction of payments for capacity. This demonstrates that Annual DR had a significant impact on market outcomes and resulted in the displacement of generation resources. Thus, even when the DR product is limited to the Annual DR product, DR has a significant and appropriate competitive impact on capacity market outcomes. As in prior BRAs, Extended Summer and Limited DR products also had a significant impact in the 2015/2016 BRA, but those impacts resulted from badly defined and inferior products.

## Impact of Environmental Regulation Compliance

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.[85] The rule requires compliance by April 16, 2015.[86]

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.[87] The rule implements performance standards on May 1, 2015, just prior to the commencement of the 2015/2016 Delivery Year.

---

85 *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).

86 *Id*. at 9465.

87 N.J.A.C. § 7:27–19.

Table 21 shows the results if the APIR associated with environmental regulation compliance, which were not previously submitted, were removed. All binding constraints would have remained the same. The RTO clearing price for Limited, Extended Summer, and Annual Resources would have decreased to $55.00 per MW-day, and the clearing quantity would have remained the same at 169,159.7 MW, with some shifting between product types. The MAAC clearing price for Limited, Extended Summer, and Annual Resources would have decreased to $116.00 per MW-day, and the clearing quantity would have increased to 66,581.8 MW. The PSEG clearing price and quantity would have remained the same. The ATSI clearing price for Limited Resources would have slightly increased to $95.89 per MW-day, and the clearing quantity would have decreased slightly to 1,001.4 MW.[88] The ATSI clearing price for Extended Summer and Annual Resources would have remained the same at $114.23 per MW-day, and the clearing quantity would have remained the same, with some shifting between product types.

Based on actual auction clearing prices and quantities and make-whole MW, total RPM market revenues for the 2016/2017 RPM Base Residual Auction were $5,513,237,849. If the APIR associated with the pending environmental regulations which were not previously submitted were removed, total RPM market revenues for the 2016/2017 RPM Base Residual Auction would have been $5,310,133,190, a reduction of $203,104,659, or 3.7 percent, compared to the total based on actual results. The impact of including environmental compliance costs in APIR was to increase total market revenues by $203,104,659, or 3.8 percent.

## Capacity Imports

Generation external to the PJM region is eligible to be offered into an RPM Auction if it meets specific requirements.[89] [90] 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

---

88 The difference in the ATSI clearing price may be attributable to differences between the PJM and MMU calculation of auction outcomes. Attachment A reviews why the MMU calculation of auction outcomes differs slightly from PJM's calculation of auction outcomes.

89 See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region", Schedule 9 & 10. <http://www.pjm.com/~/media/documents/agreements/raa.ashx>

90 See PJM. "Manual 18: PJM Capacity Market", Revision 19 (June 1, 2013), pp. 39-41 & p. 59-60.

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.[91]

Planned External Generation Capacity Resources are eligible to be offered into an RPM Auction if they meet specific requirements.[92] [93] Planned External Generation Capacity Resources are proposed Generation Capacity Resources, or a proposed increase in the capability of an Existing Generation Capacity Resource, that is located outside the PJM region; participates in the generation interconnection process of a balancing authority external to PJM; is scheduled to be physically and electrically interconnected to the transmission facilities of such balancing authority on or before the first day of the delivery year for which the resource is to be committed to satisfy the reliability requirements of the PJM Region; and is in full commercial operation prior to the first day of the delivery year.[94] 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.[95]

---

91 OATT, Schedule 1, Section 1.10.1A.

92 See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region", Section 1.69A. <http://www.pjm.com/~/media/documents/agreements/raa.ashx>

93 See PJM. "Manual 18: PJM Capacity Market", Revision 19 (June 1, 2013), pp. 42-43.

94 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).

95 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).

## Impact of Imports

Table 22 shows the results if import offers for external generation resources in the 2016/2017 RPM Base Residual Auction were reduced by 25 percent. All binding constraints would have remained the same, except that the RTO Minimum Extended Summer Resource Requirement would have been a binding constraint. The RTO clearing price for Limited Resources would have increased to $77.51 per MW-day, and the clearing quantity would have increased to 10,399.5 MW. The RTO clearing price for Extended Summer and Annual Resources would have increased to $77.82 per MW-day, and the clearing quantity would have decreased to 158,512.2 MW. The MAAC clearing price for Limited Resources would have decreased slightly to $119.12 per MW-day, and the clearing quantity would have decreased to 4,238.1 MW. The MAAC clearing price for Extended Summer and Annual Resources would have increased to $119.43 per MW-day, and the clearing quantity would have increased to 62,308.0 MW. The PSEG clearing price for Limited Resources would have decreased slightly to $218.69 per MW-day, and the clearing quantity would have remained the same at 550.4 MW. The PSEG clearing price for Extended Summer and Annual Resources would have remained the same at $219.00 per MW-day, and the clearing quantity would have increased slightly to 5,748.7 MW. The ATSI clearing price for Limited Resources would have increased to $95.71 per MW-day, and the clearing quantity would have decreased slightly to 1,001.6 MW. The ATSI clearing price for Extended Summer and Annual Resources would have remained the same at $114.23 per MW-day, and the clearing quantity would have remained the same at 7,668.1 MW with some shifting between product types.

Based on actual auction clearing prices and quantities and make-whole MW, total RPM market revenues for the 2016/2017 RPM Base Residual Auction were $5,513,237,849. If offers for external generation were reduced by 25 percent, total RPM market revenues for the 2016/2017 RPM Base Residual Auction would have been $6,150,779,857, an increase of $637,542,008, or 12 percent, compared to the actual results. The impact of including 75 percent of the offers for external generation resources was to decrease total market revenues by $637,542,008, or 10 percent.

Table 22 shows the results if offers for external generation resources in the 2016/2017 RPM Base Residual Auction were reduced by 75 percent. The RTO Minimum Extended Summer Resource Requirement would have been a binding constraint. The MAAC and ATSI import limits would not have been binding constraints. The RTO clearing price for Limited Resources would have increased to $117.18 per MW-day, and the clearing quantity would have decreased to 9,537.9 MW. The RTO clearing price for Extended Summer and Annual Resources would have increased to $124.00 per MW-day, and the clearing quantity would have decreased to 158,512.2 MW. The PSEG clearing price for Limited Resources would have decreased to $212.18 per MW-day, and the clearing quantity would have decreased to 443.6 MW. The PSEG clearing price for Extended

Summer and Annual Resources would have remained the same at $219.00 per MW-day, and the clearing quantity would have increased to 5,866.5 MW.

Based on actual auction clearing prices and quantities and make-whole MW, total RPM market revenues for the 2016/2017 RPM Base Residual Auction were $5,513,237,849. If offers for external generation were reduced by 75 percent, total RPM market revenues for the 2016/2017 RPM Base Residual Auction would have been $7,814,811,849, an increase of $2,301,574,000, or 42 percent, compared to the actual results. The impact of including 25 percent of the offers for external generation resources was to decrease total market revenues by $2,301,574,000, or 29 percent.

Of the 7,493.7 MW offered for external generation resources in the 2016/2017 RPM Base Residual Auction, 2,694.7 MW or 36.0 percent did not have firm transmission at the time of the auction.[96] Table 22 shows the results if offers for external generation resources in the 2016/2017 RPM Base Residual Auction without firm transmission were excluded. All binding constraints would have remained the same, except that the RTO Minimum Extended Summer Resource Requirement would have been a binding constraint. The RTO clearing price for Limited Resources would have increased to $90.00 per MW-day, and the clearing quantity would have increased to 10,186.8 MW. The RTO clearing price for Extended Summer and Annual Resources would have increased to $95.00 per MW-day, and the clearing quantity would have increased to 158,512.2 MW. The MAAC clearing price for Limited Resources would have decreased slightly to $119.12 per MW-day, and the clearing quantity would have decreased to 4,203.9 MW. The MAAC clearing price for Extended Summer and Annual Resources would have increased to $124.12 per MW-day, and the clearing quantity would have increased to 62,342.7 MW. The PSEG clearing price for Limited Resources would have decreased to $214.00 per MW-day, and the clearing quantity would have remained the same at 550.4 MW. The PSEG clearing price for Extended Summer and Annual Resources would have remained the same at $219.00 per MW-day, and the clearing quantity would have increased slightly to 5,749.0 MW. The ATSI clearing price for Limited Resources would have decreased to $90.00 per MW-day, and the clearing quantity would have decreased slightly to 1,002.4 MW. The ATSI clearing price for Extended Summer and Annual Resources would have remained the same at $114.23 per MW-day, and the clearing quantity would have remained the same at 7,668.1 MW with some shifting between product types.

---

[96] The analysis of the impact of capacity import was revised from the IMM Capacity Deliverability presentation in Docket No. AD12-16, which can be accessed at: <http://www.monitoringanalytics.com/reports/Presentations/2013/IMM_FERC_Capacity_Deliverability_20130620.pdf>.

Based on actual auction clearing prices and quantities and make-whole MW, total RPM market revenues for the 2016/2017 RPM Base Residual Auction were $5,513,237,849. If offers for external generation resources without firm transmission were excluded, total RPM market revenues for the 2016/2017 RPM Base Residual Auction would have been $6,810,335,209, an increase of $1,297,097,360, or 24 percent, compared to the actual results. The impact of including external generation resources with only firm transmission was to decrease total market revenues by $1,297,097,360, or 19 percent.

## Tables and Figures for RTO Market

### Table 6 RTO offer statistics: 2016/2017 RPM Base Residual Auction

| | ICAP (MW) | UCAP (MW) | Percent of Available ICAP | Percent of Available UCAP |
|---|---|---|---|---|
| Generation capacity | 192,570.5 | 183,246.8 | | |
| DR capacity | 15,639.1 | 16,282.2 | | |
| EE capacity | 1,268.5 | 1,319.1 | | |
| Total internal RTO capacity | 209,478.1 | 200,848.1 | | |
| | | | | |
| FRR | (15,576.6) | (14,465.5) | | |
| Imports | 8,412.2 | 7,941.5 | | |
| RPM capacity | 202,313.7 | 194,324.1 | | |
| | | | | |
| Exports | (1,218.8) | (1,211.6) | | |
| FRR optional | (2,592.5) | (2,225.4) | | |
| Excused Existing Generation Capacity Resources | (4,389.0) | (3,620.6) | | |
| Unoffered Planned Generation Capacity Resources | (1,541.3) | (1,451.1) | | |
| Unoffered DR and EE | (1,380.1) | (1,435.4) | | |
| Available | 191,192.0 | 184,380.0 | 100.0% | 100.0% |
| | | | | |
| Generation offered | 176,145.3 | 168,716.0 | 92.1% | 91.5% |
| DR offered | 13,932.9 | 14,507.2 | 7.3% | 7.9% |
| EE offered | 1,112.6 | 1,156.8 | 0.6% | 0.6% |
| Total offered | 191,190.8 | 184,380.0 | 100.0% | 100.0% |
| | | | | |
| Unoffered Existing Generation Capacity Resources | 1.2 | 0.0 | 0.0% | 0.0% |
| | | | | |
| Cleared in RTO | | 162,028.8 | | 87.9% |
| Cleared in LDAs | | 7,130.9 | | 3.9% |
| Total cleared | | 169,159.7 | | 91.7% |
| | | | | |
| Make-whole | | 0.0 | | 0.0% |
| | | | | |
| Uncleared generation | | 13,081.7 | | 7.1% |
| Uncleared DR | | 2,099.1 | | 1.1% |
| Uncleared EE | | 39.5 | | 0.0% |
| Total uncleared | | 15,220.3 | | 8.3% |
| | | | | |
| Reliability requirement | | 166,127.5 | | |
| | | | | |
| Total cleared plus make-whole | | 169,159.7 | | |
| | | | | |
| Short-Term Resource Procurement Target | | 4,153.2 | | |
| | | | | |
| Net excess/(deficit) | | 7,185.4 | | |
| | | | | |
| Resource clearing price for Limited Resources ($ per MW-day) | | $59.37 | | |
| Resource clearing price for Extended Summer Resources ($ per MW-day) | | $59.37 | | |
| Resource clearing price for Annual Resources ($ per MW-day) | | $59.37 | | |
| Preliminary zonal capacity price ($ per MW-day) | | $59.37 | A | |
| Base zonal CTR credit rate ($ per MW-day) | | $0.00 | B | |
| Preliminary net load price ($ per MW-day) | | $59.37 | A-B | |

**Table 7 Capacity modifications (ICAP): 2016/2017 RPM Base Residual Auction**[97]

| | ICAP (MW) | | | |
|---|---|---|---|---|
| | RTO | MAAC | PSEG | ATSI |
| Generation increases | 7,407.1 | 3,526.8 | 143.6 | 806.5 |
| Generation decreases | (5,130.5) | (3,188.8) | (375.1) | (217.0) |
| Capacity modifications net increase/(decrease) | 2,276.6 | 338.0 | (231.5) | 589.5 |
| | | | | |
| DR increases | 5,739.8 | 2,007.2 | 204.2 | 770.2 |
| DR decreases | (16,066.5) | (8,254.6) | (1,156.1) | (1,535.7) |
| DR net increase/(decrease) | (10,326.7) | (6,247.4) | (951.9) | (765.5) |
| | | | | |
| EE increases | 603.8 | 221.6 | 10.9 | 199.1 |
| EE decreases | (351.9) | (80.8) | (7.6) | (73.7) |
| EE modifications increase/(decrease) | 251.9 | 140.8 | 3.3 | 125.4 |
| | | | | |
| EKPC generation | 2,746.0 | | | |
| EKPC DR | 132.1 | | | |
| EKPC EE | 0.0 | | | |
| | | | | |
| Net internal capacity increase/(decrease) | (4,920.1) | (5,768.6) | (1,180.1) | (50.6) |

97 Only cap mods and EE mods that had a start date on or before June 1, 2016 and DR plans for the 2016/2017 Base Residual Auction are included.

**Table 8 Capacity modifications (UCAP): 2016/2017 RPM Base Residual Auction**

| | UCAP (MW) | | | |
|---|---|---|---|---|
| | RTO | MAAC | PSEG | ATSI |
| Generation increases | 7,189.0 | 3,392.9 | 135.6 | 819.5 |
| Generation decreases | (4,293.1) | (2,735.1) | (329.1) | (144.7) |
| Capacity modifications net increase/(decrease) | 2,895.9 | 657.8 | (193.5) | 674.8 |
| | | | | |
| DR increases | 5,971.7 | 2,087.8 | 212.5 | 801.6 |
| DR decreases | (16,661.8) | (8,560.0) | (1,199.1) | (1,593.0) |
| DR net increase/(decrease) | (10,690.1) | (6,472.2) | (986.6) | (791.4) |
| | | | | |
| EE increases | 626.9 | 229.1 | 11.1 | 207.4 |
| EE decreases | (364.4) | (83.5) | (7.9) | (76.4) |
| EE modifications increase/(decrease) | 262.5 | 145.6 | 3.2 | 131.0 |
| | | | | |
| Net capacity/DR/EE modifications increase/(decrease) | (7,531.7) | (5,668.8) | (1,176.9) | 14.4 |
| | | | | |
| EFORd effect | 1,039.0 | 575.2 | (0.6) | (101.8) |
| | | | | |
| DR and EE effect | 47.8 | 18.4 | 2.1 | 5.1 |
| | | | | |
| EKPC generation | 2,598.2 | | | |
| EKPC DR | 137.5 | | | |
| EKPC EE | 0.0 | | | |
| | | | | |
| Net internal capacity increase/(decrease) | (3,709.2) | (5,075.2) | (1,175.4) | (82.3) |

**Table 9 Cleared MW by zone and resource type/fuel source: 2016/2017 RPM Base Residual Auction**[98]

| | Cleared UCAP (MW) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Zone | DR | EE | Coal | Gas | Hydroelectric | Nuclear | Oil | Solar | Solid Waste | Wind | Total |
| AECO | 172.3 | 1.7 | 444.8 | 1,717.8 | 0.0 | 0.0 | 176.7 | 13.3 | 0.0 | 0.0 | 2,526.6 |
| AEP | 1,377.2 | 118.7 | 6,051.3 | 7,751.8 | 74.6 | 0.0 | 0.0 | 0.0 | 0.0 | 202.4 | 15,576.0 |
| AP | 684.6 | 14.4 | 3,772.7 | 2,344.5 | 120.6 | 0.0 | 0.0 | 12.7 | 0.0 | 133.7 | 7,083.2 |
| ATSI | 1,811.9 | 196.6 | 2,337.7 | 2,120.9 | 0.0 | 2,034.6 | 170.5 | 0.0 | 0.0 | 0.0 | 8,672.2 |
| BGE | 936.6 | 124.9 | 1,937.2 | 573.0 | 0.0 | 1,681.7 | 647.1 | 0.0 | 55.8 | 0.0 | 5,956.3 |
| ComEd | 1,236.2 | 426.7 | 4,241.4 | 9,004.4 | 0.0 | 9,914.6 | 197.6 | 0.0 | 0.0 | 325.4 | 25,346.3 |
| DAY | 246.8 | 12.9 | 2,671.1 | 1,333.1 | 108.7 | 0.0 | 57.0 | 0.6 | 0.0 | 0.0 | 4,430.2 |
| DEOK | 304.4 | 5.2 | 2,394.3 | 73.6 | 0.0 | 0.0 | 256.4 | 0.0 | 0.0 | 0.0 | 3,033.9 |
| DLCO | 143.1 | 4.3 | 636.2 | 145.7 | 0.0 | 1,763.2 | 13.8 | 0.0 | 0.0 | 0.0 | 2,706.3 |
| Dominion | 1,120.6 | 28.4 | 5,090.8 | 10,429.0 | 3,398.3 | 3,575.5 | 1,695.0 | 3.2 | 210.4 | 0.0 | 25,551.2 |
| DPL | 439.5 | 21.2 | 400.4 | 3,068.5 | 0.0 | 0.0 | 920.0 | 2.3 | 0.0 | 0.0 | 4,851.9 |
| EKPC | 133.1 | 0.0 | 1,743.6 | 724.7 | 129.9 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2,731.3 |
| EXT | 0.0 | 0.0 | 4,051.7 | 2,914.4 | 472.3 | 12.3 | 0.0 | 0.0 | 0.0 | 32.0 | 7,482.7 |
| JCPL | 222.7 | 4.9 | 0.0 | 2,815.0 | 387.6 | 592.3 | 167.0 | 14.7 | 8.9 | 0.0 | 4,213.1 |
| Met-Ed | 313.6 | 10.4 | 112.6 | 2,061.5 | 18.4 | 768.3 | 222.8 | 0.0 | 75.6 | 0.0 | 3,583.2 |
| PECO | 531.1 | 11.5 | 8.1 | 2,580.5 | 1,629.0 | 4,569.4 | 760.5 | 1.0 | 97.1 | 0.0 | 10,188.2 |
| PENELEC | 431.5 | 9.9 | 4,310.2 | 1,033.1 | 491.3 | 0.0 | 66.8 | 0.0 | 40.4 | 145.4 | 6,528.6 |
| Pepco | 663.9 | 83.5 | 2,327.9 | 1,584.1 | 0.0 | 0.0 | 1,384.6 | 0.0 | 49.7 | 0.0 | 6,093.7 |
| PPL | 998.2 | 30.2 | 3,256.2 | 3,369.3 | 703.5 | 2,467.6 | 1,987.8 | 5.7 | 12.8 | 31.6 | 12,862.9 |
| PSEG | 630.7 | 11.9 | 892.9 | 4,562.5 | 0.5 | 3,421.6 | 11.6 | 36.3 | 163.8 | 0.0 | 9,731.8 |
| RECO | 10.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 10.1 |
| Total | 12,408.1 | 1,117.3 | 46,681.1 | 60,207.4 | 7,534.7 | 30,801.1 | 8,735.2 | 89.8 | 714.5 | 870.5 | 169,159.7 |

**Table 10 Uncleared generation offers by technology type and age: 2016/2017 RPM Base Residual Auction**

| | Uncleared UCAP (MW) | | |
|---|---|---|---|
| Technology Type | Less Than or Equal to 40 Years Old | Greater than 40 Years Old | Total |
| Combined cycle | 2,117.3 | 0.0 | 2,117.3 |
| Combustion turbine | 246.1 | 72.1 | 318.2 |
| Oil or gas steam | 777.1 | 134.1 | 911.2 |
| Subcritical/supercritical coal | 2,493.2 | 7,241.8 | 9,735.0 |
| Other | 0.0 | 0.0 | 0.0 |
| Total | 5,633.7 | 7,448.0 | 13,081.7 |

98 Resources that operate at or above 500 kV may be physically located in a zonal LDA but are modeled in the parent LDA. For example, 3,433.2 MW of the 9,731.8 cleared MW in the PSEG Zone were modeled and cleared in the EMAAC LDA.

### Table 11 Uncleared generation resources in multiple auctions

| Technology | 2016/2017 Uncleared UCAP (MW) | Number of Resources | 2015/2016 Results for Same Set of Resources Uncleared UCAP (MW) | Number of Resources | 2014/2015 Results for Same Set of Resources Uncleared UCAP (MW) | Number of Resources |
|---|---|---|---|---|---|---|
| Combined cycle | 2,117.3 | 7 | 670.6 | 1 | 0.0 | 0 |
| Combustion turbine | 318.2 | 15 | 0.0 | 0 | 0.0 | 0 |
| Oil or gas steam | 911.2 | 7 | 57.3 | 2 | 56.5 | 2 |
| Subcritical/supercritical coal | 9,735.0 | 27 | 4,573.6 | 12 | 215.5 | 1 |
| Other | 0.0 | 0 | 0.0 | 0 | 0.0 | 0 |
| Total | 13,081.7 | 56 | 5,301.5 | 15 | 272.0 | 3 |

### Table 12 PJM LDA CETL and CETO Values: 2015/2016 and 2016/2017 RPM Base Residual Auctions

| | 2015/2016 | | | 2016/2017 | | | Change | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | CETL to CETO | | | CETL to CETO | CETO | | CETL | |
| LDA | CETO | CETL | Ratio | CETO | CETL | Ratio | MW | Percentage | MW | Percentage |
| MAAC | 100.0 | 6,156.0 | 6156% | 5,220.0 | 6,495.0 | 124% | 5,120.0 | 5,120% | 339.0 | 6% |
| EMAAC | 3,860.0 | 9,177.0 | 238% | 6,140.0 | 8,916.0 | 145% | 2,280.0 | 59% | (261.0) | (3%) |
| SWMAAC | 4,720.0 | 8,373.0 | 177% | 5,840.0 | 8,786.0 | 150% | 1,120.0 | 24% | 413.0 | 5% |
| PSEG | 4,600.0 | 6,220.0 | 135% | 6,450.0 | 6,581.0 | 102% | 1,850.0 | 40% | 361.0 | 6% |
| PSEG North | 2,240.0 | 2,972.0 | 133% | 2,450.0 | 2,936.0 | 120% | 210.0 | 9% | (36.0) | (1%) |
| DPL South | 1,510.0 | 1,822.0 | 121% | 1,580.0 | 1,901.0 | 120% | 70.0 | 5% | 79.0 | 4% |
| Pepco | 3,380.0 | 6,522.0 | 193% | 2,730.0 | 6,846.0 | 251% | (650.0) | (19%) | 324.0 | 5% |
| ATSI | 5,280.0 | 5,417.8 | 103% | 5,390.0 | 7,881.0 | 146% | 110.0 | 2% | 2,463.2 | 45% |
| ATSI Cleveland | NA | NA | NA | 3,800.0 | 5,245.0 | 138% | NA | NA | NA | NA |

### Table 13 Offers greater than $35.00 per MW-day on total RTO supply curve: 2016/2017 RPM Base Residual Auction[99]

| Technology/Resource Type | Offered UCAP (MW) | Percent of Offers |
|---|---|---|
| Subcritical/supercritical coal | 14,384.7 | 50.5% |
| Demand Resource coupled | 4,476.9 | 15.7% |
| Combined cycle | 3,225.8 | 11.3% |
| Oil or gas steam | 2,953.2 | 10.4% |
| Combustion turbine | 2,284.7 | 8.0% |
| Demand Resource non-coupled | 1,093.8 | 3.8% |
| Other generation | 43.8 | 0.2% |
| Energy Efficiency Resource | 41.7 | 0.1% |
| Total | 28,504.6 | 100.0% |

[99] For uncleared coupled DR offers, the offer with the lowest sell offer price within a coupled Demand Resource group was assumed in the offered capacity values reported.

**Table 14 Impact of Short-Term Resource Procurement Target: 2016/2017 RPM Base Residual Auction**

| | | Actual Auction Results | | No Short-Term Resource Procurement Target Reduction | |
|---|---|---|---|---|---|
| LDA | Product Type | Clearing Prices ($ per MW-day) | Cleared UCAP (MW) | Clearing Prices ($ per MW-day) | Cleared UCAP (MW) |
| RTO | Limited | $59.37 | 9,849.5 | $85.71 | 11,299.8 |
| | Extended Summer | $59.37 | 2,470.0 | $85.71 | 1,987.8 |
| | Annual | $59.37 | 156,840.2 | $85.71 | 159,599.3 |
| MAAC | Limited | $119.13 | 4,264.3 | $130.00 | 4,610.9 |
| | Extended Summer | $119.13 | 1,053.4 | $130.00 | 851.3 |
| | Annual | $119.13 | 61,228.7 | $130.00 | 62,626.4 |
| PSEG | Limited | $219.00 | 550.4 | $239.90 | 593.6 |
| | Extended Summer | $219.00 | 61.8 | $239.90 | 22.2 |
| | Annual | $219.00 | 5,686.4 | $239.90 | 5,936.4 |
| ATSI | Limited | $94.45 | 1,004.1 | $122.97 | 1,311.1 |
| | Extended Summer | $114.23 | 799.3 | $122.97 | 519.2 |
| | Annual | $114.23 | 6,868.8 | $122.97 | 7,148.9 |

## Table 15 DR and EE statistics by LDA: 2015/2016 and 2016/2017 RPM Base Residual Auctions[100] [101]

| | | 2015/2016 BRA | | | 2016/2017 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 | Percentage | MW | Percentage | MW | Percentage |
| RTO | DR | 19,243.6 | 19,956.3 | 14,832.8 | 13,932.9 | 14,507.2 | 12,408.1 | (5,310.7) | (27.6%) | (5,449.1) | (27.3%) | (2,424.7) | (16.3%) |
| RTO | EE | 907.8 | 940.3 | 922.5 | 1,112.6 | 1,156.8 | 1,117.3 | 204.8 | 22.6% | 216.5 | 23.0% | 194.8 | 21.1% |
| MAAC | DR | 8,835.9 | 9,163.3 | 6,648.7 | 5,477.4 | 5,703.5 | 5,350.2 | (3,358.5) | (38.0%) | (3,459.8) | (37.8%) | (1,298.5) | (19.5%) |
| MAAC | EE | 229.1 | 237.2 | 222.6 | 318.5 | 330.9 | 310.1 | 89.4 | 39.0% | 93.7 | 39.5% | 87.5 | 39.3% |
| EMAAC | DR | 3,736.6 | 3,874.9 | 2,610.4 | 2,069.5 | 2,155.0 | 2,006.4 | (1,667.1) | (44.6%) | (1,719.9) | (44.4%) | (604.0) | (23.1%) |
| EMAAC | EE | 48.9 | 50.5 | 42.2 | 62.1 | 64.1 | 51.2 | 13.2 | 27.0% | 13.6 | 26.9% | 9.0 | 21.3% |
| SWMAAC | DR | 2,212.6 | 2,295.2 | 2,009.1 | 1,588.1 | 1,653.8 | 1,600.5 | (624.5) | (28.2%) | (641.4) | (27.9%) | (408.6) | (20.3%) |
| SWMAAC | EE | 154.2 | 159.8 | 159.4 | 200.3 | 208.6 | 208.4 | 46.1 | 29.9% | 48.8 | 30.5% | 49.0 | 30.7% |
| DPL South | DR | 127.2 | 131.9 | 86.3 | 119.1 | 124.0 | 105.7 | (8.1) | (6.4%) | (7.9) | (6.0%) | 19.4 | 22.5% |
| DPL South | EE | 0.0 | 0.0 | 0.0 | 0.7 | 0.7 | 0.6 | 0.7 | NA | 0.7 | NA | 0.6 | NA |
| PSEG | DR | 1,043.2 | 1,081.9 | 796.1 | 610.9 | 636.5 | 630.7 | (432.3) | (41.4%) | (445.4) | (41.2%) | (165.4) | (20.8%) |
| PSEG | EE | 11.6 | 11.9 | 10.7 | 14.6 | 14.9 | 11.9 | 3.0 | 25.9% | 3.0 | 25.2% | 1.2 | 11.2% |
| PSEG North | DR | 353.3 | 366.5 | 263.3 | 218.8 | 228.2 | 226.6 | (134.5) | (38.1%) | (138.3) | (37.7%) | (36.7) | (13.9%) |
| PSEG North | EE | 3.4 | 3.5 | 3.1 | 4.1 | 4.1 | 3.1 | 0.7 | 20.6% | 0.6 | 17.1% | 0.0 | 0.0% |
| Pepco | DR | 931.7 | 966.4 | 867.4 | 656.4 | 683.8 | 663.9 | (275.3) | (29.5%) | (282.6) | (29.2%) | (203.5) | (23.5%) |
| Pepco | EE | 54.2 | 56.2 | 55.8 | 80.3 | 83.7 | 83.5 | 26.1 | 48.2% | 27.5 | 48.9% | 27.7 | 49.6% |
| ATSI | DR | 1,965.7 | 2,038.5 | 1,763.7 | 1,844.7 | 1,920.7 | 1,811.9 | (121.0) | (6.2%) | (117.8) | (5.8%) | 48.2 | 2.7% |
| ATSI | EE | 46.5 | 48.1 | 44.9 | 191.2 | 198.9 | 196.6 | 144.7 | 311.2% | 150.8 | 313.5% | 151.7 | 337.9% |
| ATSI Cleveland | DR | NA | NA | NA | 473.4 | 492.8 | 468.7 | NA | NA | NA | NA | NA | NA |
| ATSI Cleveland | EE | NA | NA | NA | 50.8 | 52.8 | 52.6 | NA | NA | NA | NA | NA | NA |

100 The maximum capacity within a coupled Demand Resource group was assumed in the offered capacity values reported.

101 ATSI Cleveland was not a modeled LDA in the 2015/2016 BRA.

## Table 16 Offered and cleared DR by LDA and offer/product type: 2016/2017 RPM Base Residual Auction

| | | | Offered UCAP (MW) | | | Cleared UCAP (MW) | | |
|---|---|---|---|---|---|---|---|---|
| LDA | Offer Type | Product Type(s) | Annual | Extended Summer | Limited | Annual | Extended Summer | Limited |
| RTO | Non-coupled | Annual | 90.3 | 0.0 | 0.0 | 88.6 | 0.0 | 0.0 |
| RTO | Non-coupled | Extended Summer | 0.0 | 1,433.7 | 0.0 | 0.0 | 1,433.7 | 0.0 |
| RTO | Non-coupled | Limited | 0.0 | 0.0 | 4,387.9 | 0.0 | 0.0 | 4,210.5 |
| RTO | Coupled | Annual and Extended Summer | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| RTO | Coupled | Annual and Limited | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| RTO | Coupled | Extended Summer and Limited | 0.0 | 1,853.4 | 2,111.0 | 0.0 | 246.5 | 1,258.8 |
| RTO | Coupled | Annual, Extended Summer, and Limited | 2,995.6 | 6,147.7 | 6,044.3 | 0.0 | 789.8 | 4,380.2 |
| MAAC | Non-coupled | Annual | 33.2 | 0.0 | 0.0 | 32.5 | 0.0 | 0.0 |
| MAAC | Non-coupled | Extended Summer | 0.0 | 663.9 | 0.0 | 0.0 | 663.9 | 0.0 |
| MAAC | Non-coupled | Limited | 0.0 | 0.0 | 1,417.7 | 0.0 | 0.0 | 1,402.0 |
| MAAC | Coupled | Annual and Extended Summer | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| MAAC | Coupled | Annual and Limited | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| MAAC | Coupled | Extended Summer and Limited | 0.0 | 764.1 | 900.3 | 0.0 | 9.1 | 856.2 |
| MAAC | Coupled | Annual, Extended Summer, and Limited | 1,507.6 | 2,529.8 | 2,448.6 | 0.0 | 380.4 | 2,006.1 |
| PSEG | Non-coupled | Annual | 18.5 | 0.0 | 0.0 | 18.5 | 0.0 | 0.0 |
| PSEG | Non-coupled | Extended Summer | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| PSEG | Non-coupled | Limited | 0.0 | 0.0 | 257.7 | 0.0 | 0.0 | 257.7 |
| PSEG | Coupled | Annual and Extended Summer | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| PSEG | Coupled | Annual and Limited | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| PSEG | Coupled | Extended Summer and Limited | 0.0 | 75.3 | 97.4 | 0.0 | 0.7 | 96.8 |
| PSEG | Coupled | Annual, Extended Summer, and Limited | 157.8 | 239.8 | 239.1 | 0.0 | 61.1 | 195.9 |
| ATSI | Non-coupled | Annual | 8.5 | 0.0 | 0.0 | 8.5 | 0.0 | 0.0 |
| ATSI | Non-coupled | Extended Summer | 0.0 | 152.5 | 0.0 | 0.0 | 152.5 | 0.0 |
| ATSI | Non-coupled | Limited | 0.0 | 0.0 | 496.8 | 0.0 | 0.0 | 413.9 |
| ATSI | Coupled | Annual and Extended Summer | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| ATSI | Coupled | Annual and Limited | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| ATSI | Coupled | Extended Summer and Limited | 0.0 | 248.9 | 258.6 | 0.0 | 237.4 | 12.4 |
| ATSI | Coupled | Annual, Extended Summer, and Limited | 245.0 | 886.7 | 826.7 | 0.0 | 409.4 | 577.8 |

**Table 17 Weighted-average sell offer prices for DR by LDA and offer/product type: 2016/2017 RPM Base Residual Auction**

| | | | Weighted-Average ($ per MW-day UCAP) | | |
|---|---|---|---|---|---|
| LDA | Offer Type | Product Type(s) | Annual | Extended Summer | Limited |
| RTO | Non-coupled | Annual | $21.67 | | |
| RTO | Non-coupled | Extended Summer | | $5.36 | |
| RTO | Non-coupled | Limited | | | $27.95 |
| RTO | Coupled | Annual and Extended Summer | | | |
| RTO | Coupled | Annual and Limited | | | |
| RTO | Coupled | Extended Summer and Limited | | $74.08 | $60.11 |
| RTO | Coupled | Annual, Extended Summer, and Limited | $79.35 | $64.95 | $46.89 |
| MAAC | Non-coupled | Annual | $55.47 | | |
| MAAC | Non-coupled | Extended Summer | | $0.84 | |
| MAAC | Non-coupled | Limited | | | $38.99 |
| MAAC | Coupled | Annual and Extended Summer | | | |
| MAAC | Coupled | Annual and Limited | | | |
| MAAC | Coupled | Extended Summer and Limited | | $84.47 | $66.52 |
| MAAC | Coupled | Annual, Extended Summer, and Limited | $77.69 | $63.17 | $40.99 |
| PSEG | Non-coupled | Annual | $90.89 | | |
| PSEG | Non-coupled | Extended Summer | | | |
| PSEG | Non-coupled | Limited | | | $27.18 |
| PSEG | Coupled | Annual and Extended Summer | | | |
| PSEG | Coupled | Annual and Limited | | | |
| PSEG | Coupled | Extended Summer and Limited | | $79.74 | $65.29 |
| PSEG | Coupled | Annual, Extended Summer, and Limited | $85.18 | $70.24 | $56.78 |
| ATSI | Non-coupled | Annual | $0.00 | | |
| ATSI | Non-coupled | Extended Summer | | $0.00 | |
| ATSI | Non-coupled | Limited | | | $44.50 |
| ATSI | Coupled | Annual and Extended Summer | | | |
| ATSI | Coupled | Annual and Limited | | | |
| ATSI | Coupled | Extended Summer and Limited | | $64.36 | $56.67 |
| ATSI | Coupled | Annual, Extended Summer, and Limited | $61.32 | $48.28 | $32.27 |

**Table 18 Impact of DR product types: 2016/2017 RPM Base Residual Auction**

| | | Actual Auction Results | | Annual Resources Only | |
|---|---|---|---|---|---|
| LDA | Product Type | Clearing Prices ($ per MW-day) | Cleared UCAP (MW) | Clearing Prices ($ per MW-day) | Cleared UCAP (MW) |
| RTO | Limited | $59.37 | 9,849.5 | | |
| | Extended Summer | $59.37 | 2,470.0 | | |
| | Annual | $59.37 | 156,840.2 | $153.74 | 167,254.1 |
| MAAC | Limited | $119.13 | 4,264.3 | | |
| | Extended Summer | $119.13 | 1,053.4 | | |
| | Annual | $119.13 | 61,228.7 | $175.00 | 65,915.3 |
| PSEG | Limited | $219.00 | 550.4 | | |
| | Extended Summer | $219.00 | 61.8 | | |
| | Annual | $219.00 | 5,686.4 | $277.10 | 6,200.6 |
| ATSI | Limited | $94.45 | 1,004.1 | | |
| | Extended Summer | $114.23 | 799.3 | | |
| | Annual | $114.23 | 6,868.8 | $153.74 | 9,943.2 |

**Table 19 Impact of Short Term Resource Procurement Target and DR product types: 2016/2017 RPM Base Residual Auction**

| | | Actual Auction Results | | No Short-Term Resource Procurement Target Reduction and Annual Resources Only | |
|---|---|---|---|---|---|
| LDA | Product Type | Clearing Prices ($ per MW-day) | Cleared UCAP (MW) | Clearing Prices ($ per MW-day) | Cleared UCAP (MW) |
| RTO | Limited | $59.37 | 9,849.5 | | |
| | Extended Summer | $59.37 | 2,470.0 | | |
| | Annual | $59.37 | 156,840.2 | $243.46 | 169,457.4 |
| MAAC | Limited | $119.13 | 4,264.3 | | |
| | Extended Summer | $119.13 | 1,053.4 | | |
| | Annual | $119.13 | 61,228.7 | $266.49 | 66,546.8 |
| PSEG | Limited | $219.00 | 550.4 | | |
| | Extended Summer | $219.00 | 61.8 | | |
| | Annual | $219.00 | 5,686.4 | $360.37 | 6,318.2 |
| ATSI | Limited | $94.45 | 1,004.1 | | |
| | Extended Summer | $114.23 | 799.3 | | |
| | Annual | $114.23 | 6,868.8 | $243.46 | 10,329.4 |

**Table 20 Impact of DR: 2016/2017 RPM Base Residual Auction**

| | | Actual Auction Results | | No Offers for DR | |
|---|---|---|---|---|---|
| LDA | Product Type | Clearing Prices ($ per MW-day) | Cleared UCAP (MW) | Clearing Prices ($ per MW-day) | Cleared UCAP (MW) |
| RTO | Limited | $59.37 | 9,849.5 | | |
| | Extended Summer | $59.37 | 2,470.0 | | |
| | Annual | $59.37 | 156,840.2 | $243.79 | 165,296.7 |
| MAAC | Limited | $119.13 | 4,264.3 | | |
| | Extended Summer | $119.13 | 1,053.4 | | |
| | Annual | $119.13 | 61,228.7 | $279.22 | 64,723.0 |
| PSEG | Limited | $219.00 | 550.4 | | |
| | Extended Summer | $219.00 | 61.8 | | |
| | Annual | $219.00 | 5,686.4 | $317.17 | 6,132.9 |
| ATSI | Limited | $94.45 | 1,004.1 | | |
| | Extended Summer | $114.23 | 799.3 | | |
| | Annual | $114.23 | 6,868.8 | $243.79 | 9,879.7 |

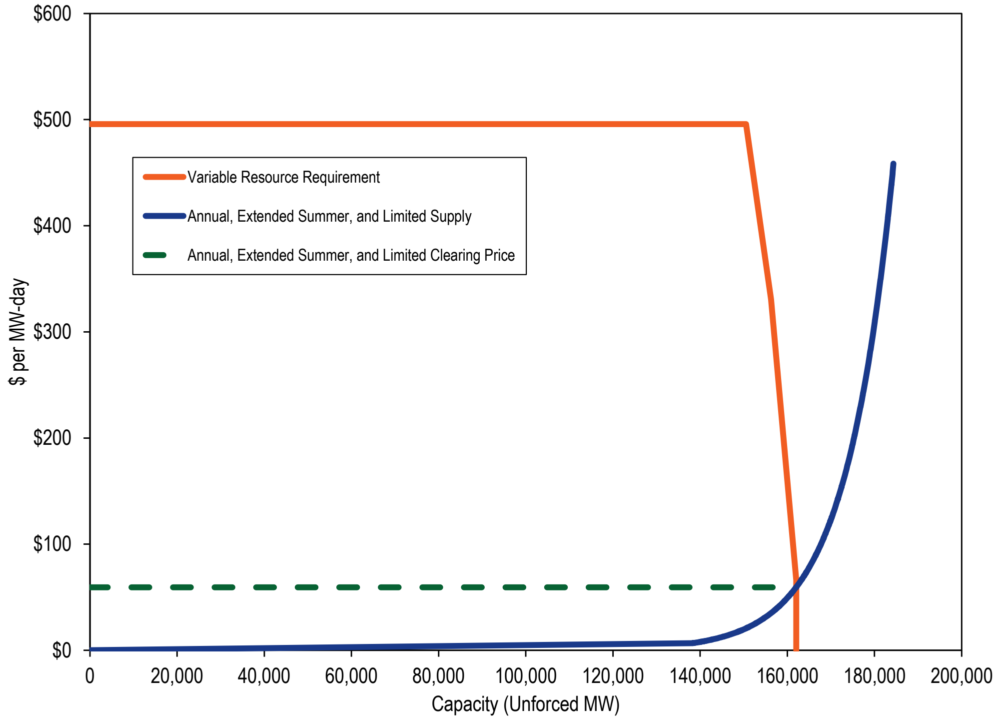
**Table 21 Impact of environmental regulations: 2016/2017 RPM Base Residual Auction**

| | | Actual Auction Results | | Remove APIR Associated with Environmental Regulations | |
|---|---|---|---|---|---|
| LDA | Product Type | Clearing Prices ($ per MW-day) | Cleared UCAP (MW) | Clearing Prices ($ per MW-day) | Cleared UCAP (MW) |
| RTO | Limited | $59.37 | 9,849.5 | $55.00 | 9,967.2 |
| | Extended Summer | $59.37 | 2,470.0 | $55.00 | 2,310.1 |
| | Annual | $59.37 | 156,840.2 | $55.00 | 156,882.4 |
| MAAC | Limited | $119.13 | 4,264.3 | $116.00 | 4,402.5 |
| | Extended Summer | $119.13 | 1,053.4 | $116.00 | 893.7 |
| | Annual | $119.13 | 61,228.7 | $116.00 | 61,285.6 |
| PSEG | Limited | $219.00 | 550.4 | $219.00 | 586.8 |
| | Extended Summer | $219.00 | 61.8 | $219.00 | 25.4 |
| | Annual | $219.00 | 5,686.4 | $219.00 | 5,686.4 |
| ATSI | Limited | $94.45 | 1,004.1 | $95.89 | 1,001.4 |
| | Extended Summer | $114.23 | 799.3 | $114.23 | 799.1 |
| | Annual | $114.23 | 6,868.8 | $114.23 | 6,869.0 |

## Table 22 Impact of capacity imports: 2016/2017 RPM Base Residual Auction

| | | Actual Auction Results | | Reduce Imports by 25 Percent | | Reduce Imports by 50 Percent | | Reduce Imports by 75 Percent | | Exclude Imports without Firm Transmission | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 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 | Limited | $59.37 | 9,849.5 | $77.51 | 10,399.5 | $104.49 | 9,812.9 | $117.18 | 9,537.9 | $90.00 | 10,186.8 |
| | Extended Summer | $59.37 | 2,470.0 | $77.82 | 2,712.4 | $106.00 | 3,697.7 | $124.00 | 4,063.0 | $95.00 | 3,004.8 |
| | Annual | $59.37 | 156,840.2 | $77.82 | 155,799.8 | $106.00 | 154,814.5 | $124.00 | 154,449.2 | $95.00 | 155,507.4 |
| MAAC | Limited | $119.13 | 4,264.3 | $119.12 | 4,238.1 | $118.49 | 3,665.4 | $117.18 | 3,441.8 | $119.12 | 4,203.9 |
| | Extended Summer | $119.13 | 1,053.4 | $119.43 | 1,078.4 | $120.00 | 1,630.8 | $124.00 | 1,854.1 | $124.12 | 1,112.7 |
| | Annual | $119.13 | 61,228.7 | $119.43 | 61,229.6 | $120.00 | 61,256.0 | $124.00 | 61,417.4 | $124.12 | 61,230.0 |
| PSEG | Limited | $219.00 | 550.4 | $218.69 | 550.4 | $217.49 | 483.8 | $212.18 | 443.6 | $214.00 | 550.4 |
| | Extended Summer | $219.00 | 61.8 | $219.00 | 61.8 | $219.00 | 128.4 | $219.00 | 168.6 | $219.00 | 61.8 |
| | Annual | $219.00 | 5,686.4 | $219.00 | 5,686.9 | $219.00 | 5,688.9 | $219.00 | 5,697.9 | $219.00 | 5,687.2 |
| ATSI | Limited | $94.45 | 1,004.1 | $95.71 | 1,001.6 | $104.49 | 1,163.8 | $117.18 | 1,207.2 | $90.00 | 1,002.4 |
| | Extended Summer | $114.23 | 799.3 | $114.23 | 799.1 | $115.00 | 650.2 | $124.00 | 623.1 | $114.23 | 799.1 |
| | Annual | $114.23 | 6,868.8 | $114.23 | 6,869.0 | $115.00 | 7,017.9 | $124.00 | 8,366.9 | $114.23 | 6,869.0 |

**Figure 1 RTO market supply/demand curves: 2016/2017 RPM Base Residual Auction[102] [103] [104]**




---

102 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.

103 For uncleared coupled DR offers, the offer with the lowest sell offer price within a coupled Demand Resource group was assumed in graphing the supply curve. The VRR curve excludes incremental demand which cleared in MAAC, PSEG, and ATSI.

104 The Minimum Extended Summer Resource Requirement and the Minimum Annual Resource Requirement were not binding constraints in RTO in the 2016/2017 RPM Base Residual Auction.

## MAAC Market Results

Table 23 shows total MAAC offer data for the 2016/2017 RPM Base Residual Auction. All MW values stated in the MAAC section include all LDAs nested within MAAC. Total internal MAAC unforced capacity of 74,717.9 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 (cap mods). As shown in Table 8, MAAC unforced internal capacity decreased 5,075.2 MW from 79,793.1 MW in the 2015/2016 BRA as a result of net generation capacity modifications (657.8 MW), net DR modifications (-6,472.2 MW), and net EE modifications (145.6 MW), the EFORd effect due to lower sell offer EFORds (575.2 MW), and the DR and EE effect due to a higher Load Management UCAP conversion factor (18.4 MW).

All imports offered in the auction from areas external to PJM are modeled as supply in the RTO, so total MAAC RPM capacity was the same as the internal capacity of 74,717.9 MW.[105] RPM capacity was reduced by 674.0 MW of exports, 677.0 MW of Planned Generation Capacity Resources which were not subject to the RPM must offer requirement, and 1,397.7 MW excused from the RPM must offer requirement. The excused Existing Generation Capacity Resources were the result of plans for retirement (1,381.9 MW) and significant physical operational restrictions (15.8 MW). Subtracting 361.7 MW of DR and EE not offered resulted in available unforced capacity in MAAC of 71,607.5 MW.[106] After accounting for the above exceptions, 0.0 MW in MAAC were not offered in the RPM Auction.

The MAAC LDA import limit was a binding constraint in the 2016/2017 BRA. Of the 66,546.4 MW cleared in MAAC, 61,003.6 MW were cleared in the RTO before MAAC became constrained. Once the constraint was binding, based on the 6,495.0 MW CETL value, only the incremental supply located in MAAC was available to meet the incremental demand in the LDA. Of the incremental supply, 5,542.8 MW cleared, which resulted in a clearing price for Limited, Extended Summer, and Annual Resources of $119.13 per MW-day, as shown in Figure 2. The clearing price was determined by the intersection of the incremental supply and VRR Curve.

The Minimum Extended Summer Resource Requirement and Minimum Annual Resource Requirement were not binding constraints for MAAC in the 2016/2017 BRA,

---

105 PJM. "Manual 18: PJM Capacity Market," Revision 19 (June 1, 2013), p. 41.

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

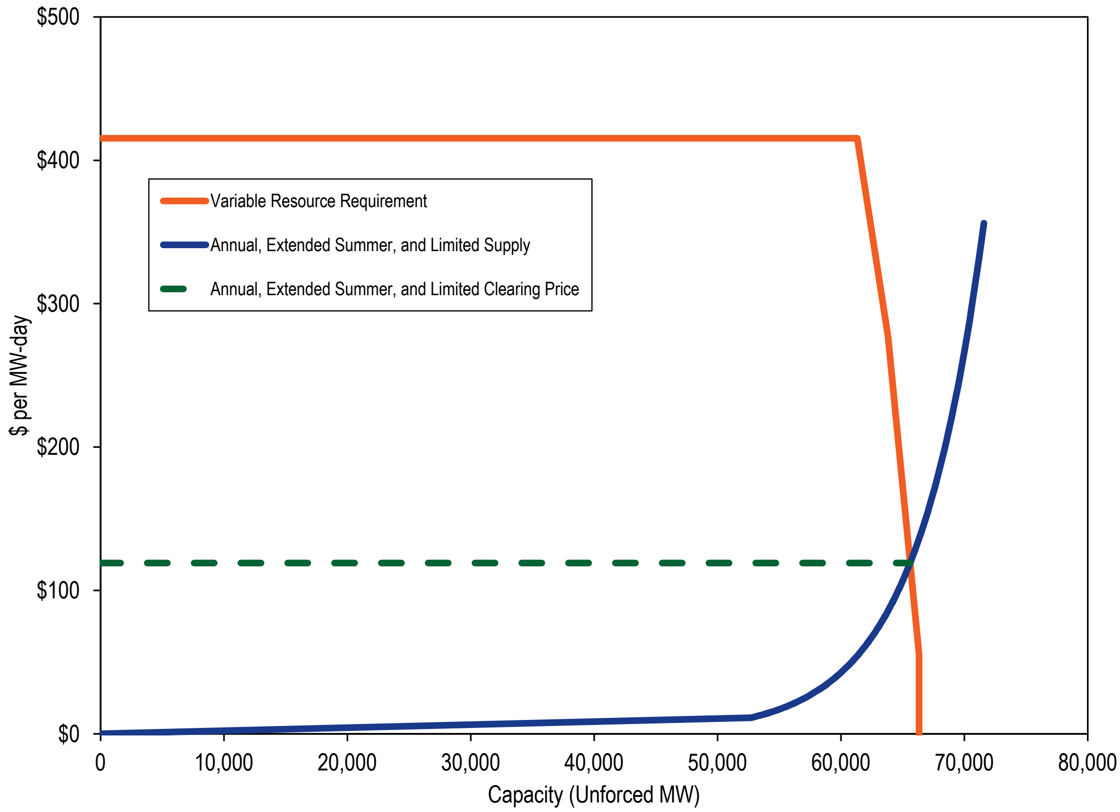
and as a result Extended Summer and Annual Resources in MAAC received a clearing price of $119.13 per MW-day.

## Table and Figures for MAAC

### Table 23 MAAC offer statistics: 2016/2017 RPM Base Residual Auction

| | ICAP (MW) | UCAP (MW) | Percent of Available ICAP | Percent of Available UCAP |
|---|---|---|---|---|
| Generation capacity | 70,834.4 | 68,321.8 | | |
| DR capacity | 5,774.7 | 6,012.0 | | |
| EE capacity | 369.9 | 384.1 | | |
| Total internal MAAC capacity | 76,979.0 | 74,717.9 | | |
| | | | | |
| FRR | 0.0 | 0.0 | | |
| Imports | 0.0 | 0.0 | | |
| RPM capacity | 76,979.0 | 74,717.9 | | |
| | | | | |
| Exports | (674.0) | (674.0) | | |
| FRR optional | 0.0 | 0.0 | | |
| Excused Existing Generation Capacity Resources | (1,514.8) | (1,397.7) | | |
| Unoffered Planned Generation Capacity Resources | (710.5) | (677.0) | | |
| Unoffered DR and EE | (348.7) | (361.7) | | |
| Available | 73,731.0 | 71,607.5 | 100.0% | 100.0% |
| | | | | |
| Generation offered | 67,933.9 | 65,573.1 | 92.1% | 91.6% |
| DR offered | 5,477.4 | 5,703.5 | 7.4% | 8.0% |
| EE offered | 318.5 | 330.9 | 0.4% | 0.5% |
| Total offered | 73,729.8 | 71,607.5 | 100.0% | 100.0% |
| | | | | |
| Unoffered | 1.2 | 0.0 | 0.0% | 0.0% |
| | | | | |
| Cleared in RTO | | 61,003.6 | | 85.2% |
| Cleared in MAAC | | 4,606.4 | | 6.4% |
| Cleared in PSEG | | 936.4 | | 1.3% |
| Total cleared | | 66,546.4 | | 92.9% |
| | | | | |
| Make-whole | | 0.0 | | 0.0% |
| | | | | |
| Reliability requirement | | 72,299.0 | | |
| | | | | |
| Total cleared plus make-whole | | 66,546.4 | | |
| CETL | | 6,495.0 | | |
| Total Resources | | 73,041.4 | | |
| | | | | |
| Short-Term Resource Procurement Target | | 1,664.7 | | |
| | | | | |
| Net excess/(deficit) | | 2,407.1 | | |
| | | | | |
| Resource clearing price for Limited Resources ($ per MW-day) | | $119.13 | | |
| Resource clearing price for Extended Summer Resources ($ per MW-day) | | $119.13 | | |
| Resource clearing price for Annual Resources ($ per MW-day) | | $119.13 | | |
| Preliminary zonal capacity price ($ per MW-day) | | $119.13 | A | |
| Base zonal CTR credit rate ($ per MW-day) | | $0.24 | B | |
| Preliminary net load price ($ per MW-day) | | $118.89 | A-B | |

**Figure 2 MAAC market supply/demand curves: 2016/2017 RPM Base Residual Auction**[107] [108]




## *PSEG LDA Market Results*

Table 24 shows total PSEG LDA offer data for the 2016/2017 RPM Base Residual Auction. Total internal PSEG LDA unforced capacity of 8,343.1 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 8, PSEG LDA unforced internal capacity decreased 1,175.4 MW from 9,518.5 MW in the 2015/2016 BRA as a

107 For uncleared coupled DR offers, the offer with the lowest sell offer price within a coupled Demand Resource group was assumed in graphing the supply curve. The VRR curve is reduced by the CETL.

108 The Minimum Extended Summer Resource Requirement and the Minimum Annual Resource Requirement were not binding constraints in MAAC in the 2016/2017 RPM Base Residual Auction.

result of net generation capacity modifications (-193.5 MW), net DR modifications (-986.6 MW), and net EE modifications (3.2 MW), the EFORd effect due to higher sell offer EFORds (-0.6 MW), and the DR and EE effect due to a higher Load Management UCAP conversion factor (2.1 MW).

All imports offered in the auction from areas external to PJM are modeled as supply in the RTO, so total PSEG LDA RPM capacity was the same as the internal capacity of 8,343.1 MW. There were no exports from PSEG LDA. RPM capacity was reduced by 161.4 MW of Planned Generation Capacity Resources which were not subject to the RPM must offer requirement and 1,381.9 MW excused from the RPM must offer requirement. The excused Existing Generation Capacity Resources were the result of plans for retirement (1,381.9 MW). Subtracting 15.5 MW of DR and EE not offered resulted in available unforced capacity in PSEG LDA of 6,784.3 MW.[109] 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 2015/2016 BRA. Of the 6,298.6 MW cleared in PSEG LDA, 5,163.7 MW were cleared in the RTO and an additional 198.5 MW cleared in MAAC before PSEG LDA became constrained. Once the constraint was binding, based on the 6,581.0 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, 936.4 MW cleared, which resulted in a clearing price for Limited, Extended Summer, and Annual Resources of $219.00 per MW-day, as shown in Figure 3. The clearing price was determined by the intersection of the incremental supply and VRR curve.

The Minimum Annual Resource Requirement and Minimum Annual Resource Requirement were not binding constraints for PSEG LDA in the 2016/2017 BRA, and as a result Extended Summer and Annual Resources in PSEG LDA received a clearing price of $219.00 per MW-day.

---

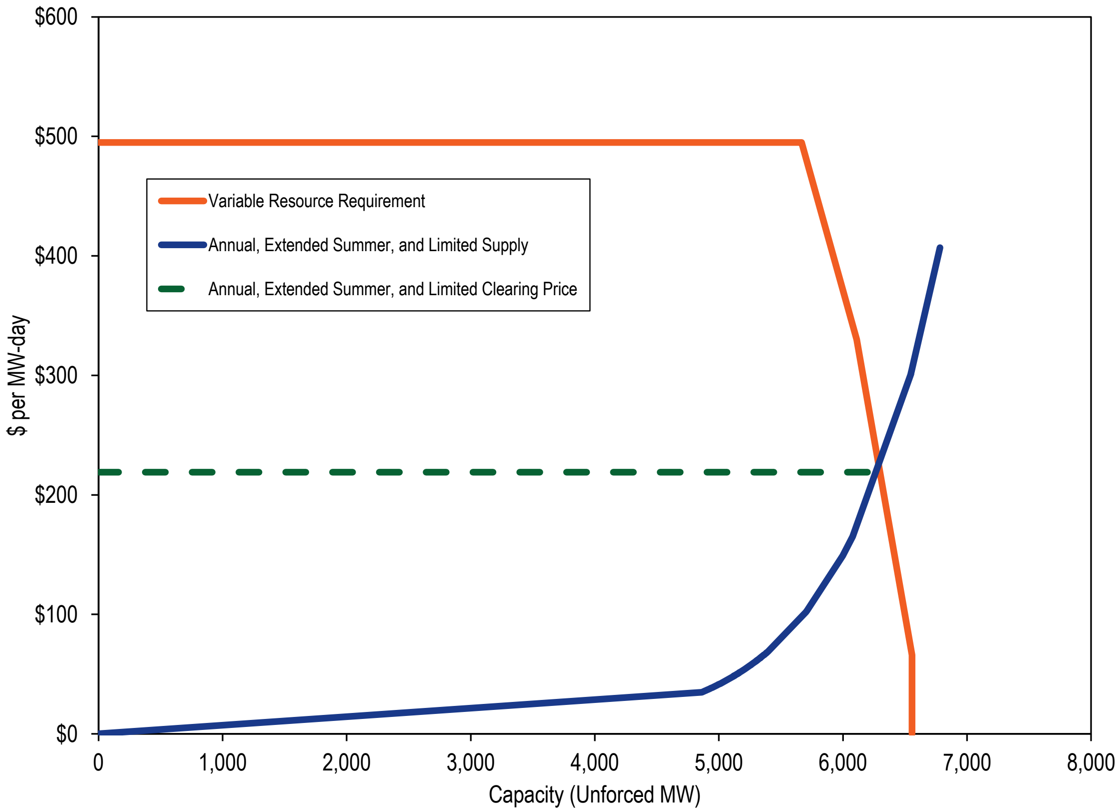
109 Unoffered DR and EE MW include PJM approved DR and EE modifications that were not offered in the auction.

## Table and Figures for PSEG LDA

### Table 24 PSEG LDA offer statistics: 2016/2017 RPM Base Residual Auction

| | ICAP (MW) | UCAP (MW) | Percent of Available ICAP | Percent of Available UCAP |
|---|---|---|---|---|
| Generation capacity | 8,076.4 | 7,676.2 | | |
| DR capacity | 625.9 | 651.7 | | |
| EE capacity | 14.9 | 15.2 | | |
| Total internal PSEG capacity | 8,717.2 | 8,343.1 | | |
| | | | | |
| FRR | 0.0 | 0.0 | | |
| Imports | 0.0 | 0.0 | | |
| RPM capacity | 8,717.2 | 8,343.1 | | |
| | | | | |
| Exports | 0.0 | 0.0 | | |
| FRR optional | 0.0 | 0.0 | | |
| Excused Existing Generation Capacity Resources | (1,492.6) | (1,381.9) | | |
| Unoffered Planned Generation Capacity Resources | (178.0) | (161.4) | | |
| Unoffered DR and EE | (15.3) | (15.5) | | |
| Available | 7,031.3 | 6,784.3 | 100.0% | 100.0% |
| | | | | |
| Generation offered | 6,405.8 | 6,132.9 | 91.1% | 90.4% |
| DR offered | 610.9 | 636.5 | 8.7% | 9.4% |
| EE offered | 14.6 | 14.9 | 0.2% | 0.2% |
| Total offered | 7,031.3 | 6,784.3 | 100.0% | 100.0% |
| | | | | |
| Unoffered | 0.0 | 0.0 | 0.0% | 0.0% |
| | | | | |
| Cleared in RTO | | 5,163.7 | | 76.1% |
| Cleared in MAAC | | 198.5 | | |
| Cleared in PSEG | | 936.4 | | 13.8% |
| Total cleared | | 6,298.6 | | 89.9% |
| | | | | |
| Make-whole | | 0.0 | | 0.0% |
| | | | | |
| Reliability requirement | | 12,870.0 | | |
| | | | | |
| Total cleared plus make-whole | | 6,298.6 | | |
| CETL | | 6,581.0 | | |
| Total Resources | | 12,879.6 | | |
| | | | | |
| Short-Term Resource Procurement Target | | 288.9 | | |
| | | | | |
| Net excess/(deficit) | | 298.5 | | |
| | | | | |
| Resource clearing price for Limited Resources ($ per MW-day) | | $219.00 | | |
| Resource clearing price for Extended Summer Resources ($ per MW-day) | | $219.00 | | |
| Resource clearing price for Annual Resources ($ per MW-day) | | $219.00 | | |
| Preliminary zonal capacity price ($ per MW-day) | | $219.00 | A | |
| Base zonal CTR credit rate ($ per MW-day) | | $41.39 | B | |
| Preliminary net load price ($ per MW-day) | | $177.61 | A-B | |

**Figure 3 PSEG LDA market supply/demand curves: 2016/2017 RPM Base Residual Auction[110] [111]**




## *ATSI Market Results*

Table 25 shows total ATSI offer data for the 2016/2017 RPM Base Residual Auction. Total internal ATSI unforced capacity of 14,325.2 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 8, ATSI unforced internal capacity decreased 82.3 MW from 14,407.5 MW in the 2015/2016 BRA as a result of net generation capacity

---

110 For uncleared coupled DR offers, the offer with the lowest sell offer price within a coupled Demand Resource group was assumed in graphing the supply curve. The VRR curve is reduced by the CETL.

111 The Minimum Extended Summer Resource Requirement and the Minimum Annual Resource Requirement were not binding constraints in PSEG in the 2016/2017 RPM Base Residual Auction.

modifications (674.8 MW), net DR modifications (-791.4 MW), and net EE modifications (131.0 MW), the EFORd effect due to higher sell offer EFORds (-101.8 MW), and the DR and EE effect due to a higher Load Management UCAP conversion factor (5.1 MW).

All imports offered in the auction from areas external to PJM are modeled as supply in the RTO, so total ATSI RPM capacity was the same as the internal capacity of 14,325.2 MW. There were no exports from ATSI. RPM capacity was reduced by 773.4 MW of Planned Generation Capacity Resources which were not subject to the RPM must offer requirement and 632.0 MW excused from the RPM must offer requirement. The excused Existing Generation Capacity Resources were the result of plans for retirement (632.0 MW). Subtracting 128.5 MW of DR and EE not offered, resulted in available unforced capacity in ATSI of 12,791.3 MW.[112] 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 2016/2017 BRA. Of the 8,672.2 MW cleared in ATSI, 7,084.1 MW were cleared in the RTO before ATSI became constrained. Once the constraint was binding, based on the 7,881.0 MW CETL value, only the incremental supply located in ATSI was available to meet the incremental demand in the LDA. Of the incremental supply, 1,588.1 MW cleared, which resulted in a clearing price for Limited Resources of $94.45 per MW-day, as shown in Figure 4. The clearing price was determined by the intersection of the incremental supply and VRR curve.

PJM's auction clearing mechanism will also result in a higher price for Extended Summer Resources if the MW of Extended Summer Resources that would otherwise clear the auction are less than the Minimum Extended Summer Resource Requirement that PJM requires for reliability. In that case the auction clearing mechanism will select Extended Summer Resources that are more expensive than the clearing price that would otherwise result in order to procure the defined minimum resource requirements for the Extended Summer product. This is referred as the Minimum Extended Summer Resource Requirement being a binding constraint.

The Minimum Extended Summer Resource Requirement was a binding constraint for ATSI in the 2016/2017 BRA, and as a result Extended Summer Resources in ATSI received a clearing price of $114.23 per MW-day. The Minimum Annual Resource Requirement was not a binding constraint in the 2016/2017 BRA, and as a result Annual Resources in ATSI received a clearing price of $114.23 per MW-day

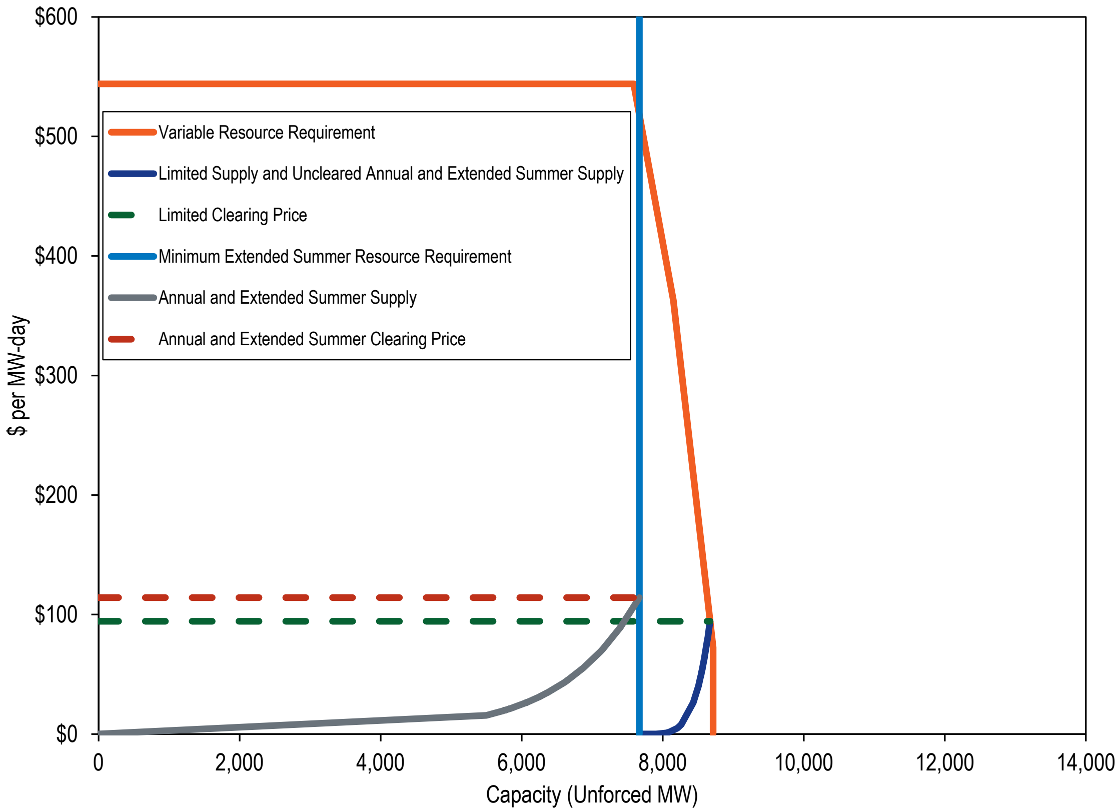
[112] Unoffered DR and EE MW include PJM approved DR and EE modifications that were not offered in the auction.

## Table and Figure for ATSI

### Table 25 ATSI offer statistics: 2016/2017 RPM Base Residual Auction

| | ICAP (MW) | UCAP (MW) | Percent of Available ICAP | Percent of Available UCAP |
|---|---|---|---|---|
| Generation capacity | 12,746.1 | 12,077.1 | | |
| DR capacity | 1,958.4 | 2,038.9 | | |
| EE capacity | 200.9 | 209.2 | | |
| Total internal ATSI capacity | 14,905.4 | 14,325.2 | | |
| | | | | |
| FRR | 0.0 | 0.0 | | |
| Imports | 0.0 | 0.0 | | |
| RPM capacity | 14,905.4 | 14,325.2 | | |
| | | | | |
| Exports | 0.0 | 0.0 | | |
| FRR optional | 0.0 | 0.0 | | |
| Excused Existing Generation Capacity Resources | (727.0) | (632.0) | | |
| Unoffered Planned Generation Capacity Resources | (830.0) | (773.4) | | |
| Unoffered DR and EE | (123.4) | (128.5) | | |
| Available | 13,225.0 | 12,791.3 | 100.0% | 100.0% |
| | | | | |
| Generation offered | 11,189.1 | 10,671.7 | 84.6% | 83.4% |
| DR offered | 1,844.7 | 1,920.7 | 13.9% | 15.0% |
| EE offered | 191.2 | 198.9 | 1.4% | 1.6% |
| Total offered | 13,225.0 | 12,791.3 | 100.0% | 100.0% |
| | | | | |
| Unoffered | 0.0 | 0.0 | 0.0% | 0.0% |
| | | | | |
| Cleared in RTO | | 7,084.1 | | 55.4% |
| Cleared in ATSI | | 1,588.1 | | 12.4% |
| Total cleared | | 8,672.2 | | 67.8% |
| | | | | |
| Make-whole | | 0.0 | | 0.0% |
| | | | | |
| Reliability requirement | | 16,255.0 | | |
| | | | | |
| Total cleared plus make-whole | | 8,672.2 | | |
| CETL | | 7,881.0 | | |
| Total Resources | | 16,553.2 | | |
| | | | | |
| Short-Term Resource Procurement Target | | 362.4 | | |
| | | | | |
| Net excess/(deficit) | | 660.6 | | |
| | | | | |
| Resource clearing price for Limited Resources ($ per MW-day) | | $94.45 | | |
| Resource clearing price for Extended Summer Resources ($ per MW-day) | | $114.23 | | |
| Resource clearing price for Annual Resources ($ per MW-day) | | $114.23 | | |
| Preliminary zonal capacity price ($ per MW-day) | | $104.48 | A | |
| Base zonal CTR credit rate ($ per MW-day) | | $13.94 | B | |
| Preliminary net load price ($ per MW-day) | | $90.54 | A-B | |

**Figure 4 ATSI market supply/demand curves: 2016/2017 RPM Base Residual Auction**[113 114]




113 For uncleared coupled DR offers, the offer with the lowest sell offer price within a coupled Demand Resource group was assumed in graphing the supply curve. The VRR curve is reduced by the CETL.

114 The Minimum Annual Resource Requirement was not a binding constraint in ATSI in the 2016/2017 RPM Base Residual Auction.

# Attachment A

## *Clearing Algorithm for RPM Base Residual Auction*

The actual clearing of the RPM Base Residual Auction 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.[115] The optimization algorithm calculates clearing prices, which are derived from the shadow prices of the binding minimum resource requirements.

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 equilibrium point is reached. The method preserves the mixed integer feature of the

115 OATT Attachment DD § 5.12(a).

optimization problem while allowing for incorporation of the minimum resource requirements. Under this approach, the price adders are directly obtained as shadow prices of the import limit constraints. Accordingly, the price adders for annual and extended summer resources are obtained from the shadow prices associated with the respective binding minimum resource requirement constraints.

In the BRA, Capacity Market Sellers are allowed to specify a minimum bound for the unforced capacity on the resource offered into the auction. If any such inflexible offers emerge as marginal or close to being marginal, the 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 below their specified minimum bound receives a make whole payment for the shortfall between the minimum bound and the unconstrained cleared MW, at the clearing price. The alternative to clearing an inflexible offer may result in clearing of higher priced offers to satisfy the applicable resource requirements. 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 the difference 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. 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. PJM did not provide the MMU with all the tolerances of all the criteria used to clear the market.
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.

## Comparison of PJM and MMU Solutions

The results of the 2016/2017 RPM Base Residual Auction conducted by PJM were replicated using the MMU's approach. The total MW cleared for every nested LDA using the MMU's algorithm is within 0.015 percent of the corresponding total MW cleared under PJM's method. The clearing prices using the MMU's approach are within 1.5 percent of the corresponding clearing prices under PJM's method.

## Recommendations

The MMU recommends two changes to the RPM solution methodology that address make-whole payments and the iterative reconfiguration of the VRR curve. These changes will result in a simpler approach to the optimization problem, which will improve the stability, transparency, and manageability of the RPM market clearing.

The RPM solution method does not explicitly include the cost of make-whole payments in its objective function. Instead, the model handles inflexible offers as part of an iterative process and make-whole payments are determined at the end. Because the additional make-whole payments are excluded from the optimization objective function, the model does not optimally balance the system to accommodate the extra cost and the extra MW of make-whole payments as part of the optimization. The MMU recommends changing the RPM solution methodology to explicitly incorporate the cost of make-whole payments in the objective function. The model would be able to choose the lower cost option of an inflexible offer and a higher priced flexible offer. The MMU's testing has shown that the proposed approach solves as fast and results in a better solution defined by overall system benefit.

PJM's RPM model maintains a nested LDA structure, in which the capacity procured towards meeting a child LDA's VRR also satisfies the nested parent LDA's VRR. To respect this relationship, 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 a convergence point, based on the difference in cleared capacity for each LDA from one iteration to the next, is reached. The purpose of the iterative approach is to jointly optimize the cost of procuring a child LDA's and the parent LDA's capacity to meet their respective VRRs. However, the joint optimization can be accomplished more efficiently with a simultaneous rather than an iterative approach by defining variables for the nesting relationships. The MMU recommends changing the RPM solution methodology to define variables for the nesting relationships in the BRA optimization model directly rather than employing the current iterative approach, in order to improve the efficiency and stability of the solution.

## 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 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 5 and Figure 6 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.[116]

Figure 7 and Figure 8 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 and Figure 10 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 respectively.

---

116 For simplicity, the minimum annual resource requirement and minimum summer extended resource requirement constraints are not included.

**Figure 5 Variable Resource Requirement Curve: Child LDA**

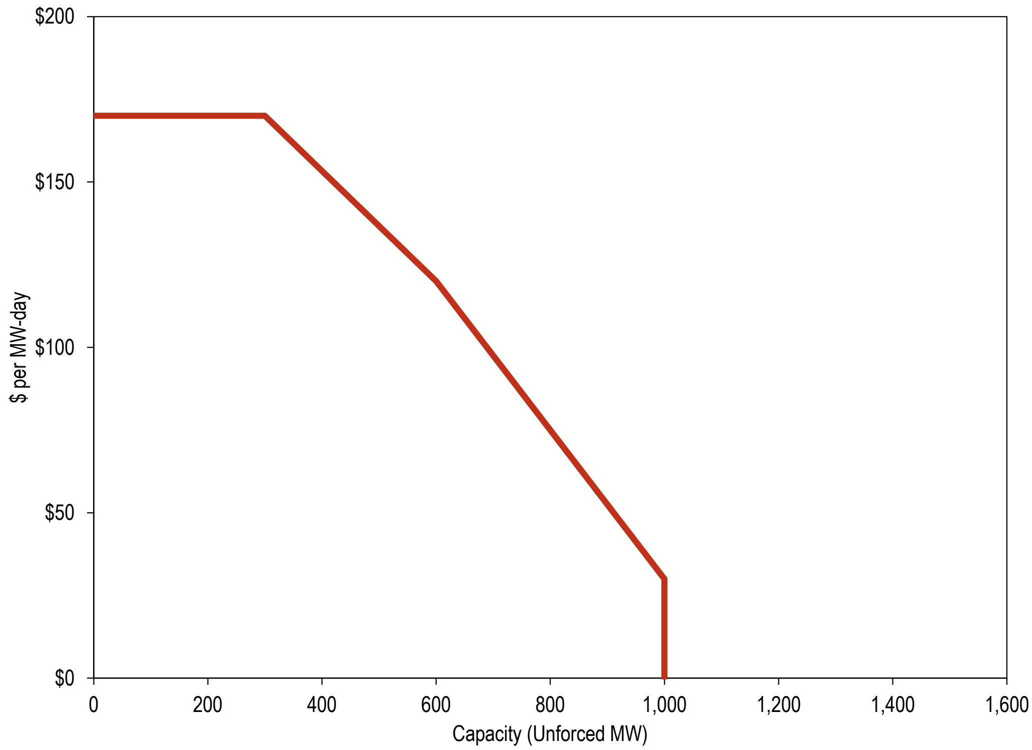



**Figure 6 Nested Variable Resource Requirement Curve: Parent LDA**

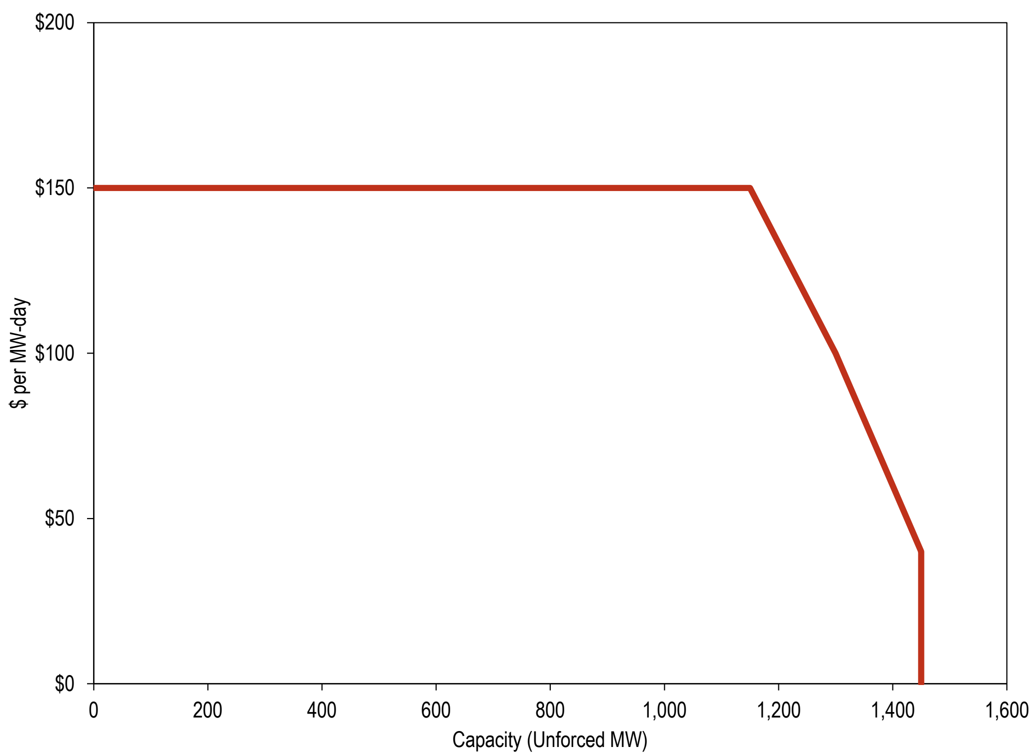


**Figure 7 Optimal solution for scenario 1: Child LDA**

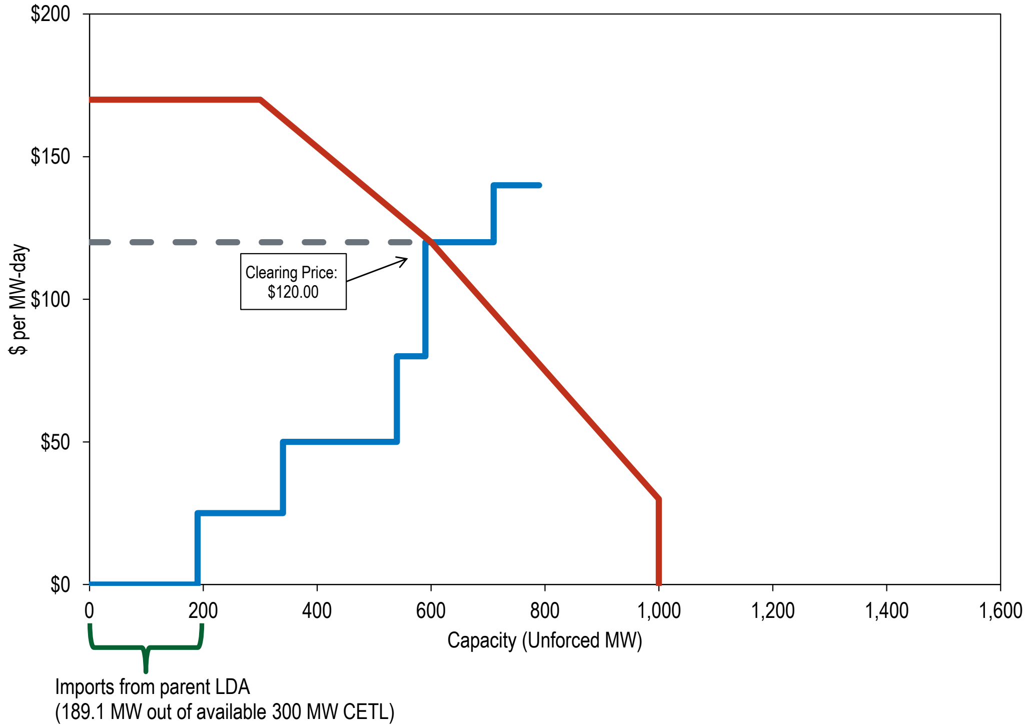
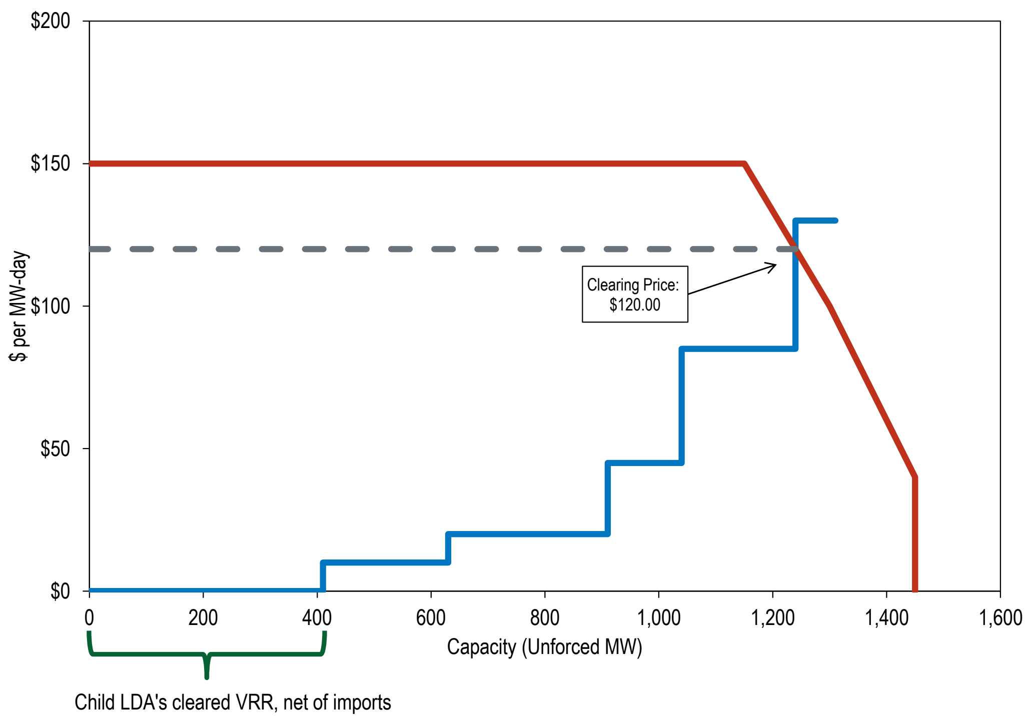
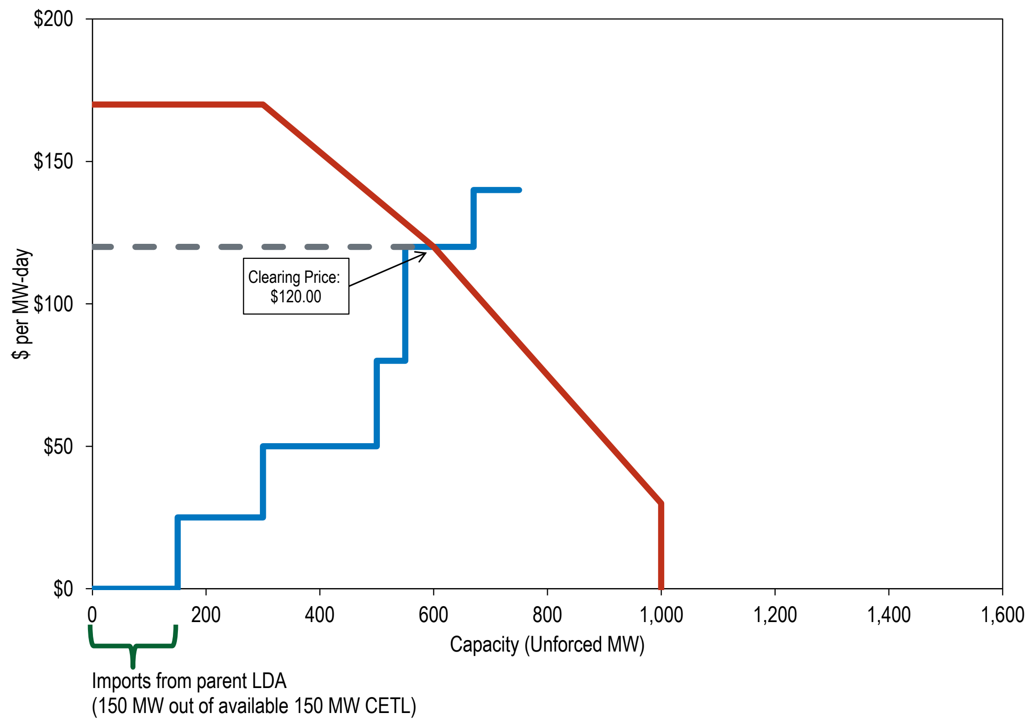



**Figure 8 Optimal solution for scenario 1: Parent LDA**



## Figure 9 Optimal solution for scenario 2: Child LDA




## Figure 10 Optimal solution for scenario 2: Parent LDA