Analysis of the 2015/2016 RPM Base Residual Auction

The Independent Market Monitor for PJM

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Introduction

This report, prepared by the Independent Market Monitor for PJM (IMM or MMU), reviews the functioning of the ninth Reliability Pricing Model (RPM) Base Residual Auction (BRA) (for the 2015/2016 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; and Avoidable Project Investment Recovery Rate (APIR) changes related to environmental regulations.

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 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.

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. 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 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, 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 of capacity. Based on these facts, the MMU concludes that the results of the 2015/2016 RPM Base Residual Auction were competitive.

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

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1 Attachment A reviews why the MMU calculation of clearing prices differs slightly from PJM's calculation of clearing prices.

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).

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 also 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. 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.[4, 5] The result is higher net revenues, which affect the parameters of the RPM demand curve and market outcomes. The MMU recommends that the rule requiring that relatively small proposed increases in the capability of a Generation Capacity Resource be treated as planned for purposes of mitigation and exempted from offer capping be removed. The MMU recommends that, as part of the MOPR unit specific standard of review, all projects be required to use the same basic modeling assumptions. That is the only way to ensure that projects compete on the basis of actual costs rather than on the basis of modeling assumptions.[6, 7]

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

5 See the *2011 State of the Market Report for PJM*, Volume II, Section 6, Net Revenue.

6 See 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).

7 PJM has filed a revised MOPR with FERC, pending in Docket No. ER13-535-000, proposing to replace unit specific cost review with exceptions for resources that can demonstrate that they are competitive suppliers, that they participated in a competitive and non-discriminatory procurement process, that they meet criteria for public power self supply, or that they meet the criteria for vertically integrated regulated utility self supply. The Market Monitor submitted comments in that docket proposing changes to address state procurement related to local reliability concerns, which would, in limited circumstances, require unit specific cost review. *See* Comments of the Independent Market Monitor for PJM, Docket No. ER13-535-000 (December 28, 2012).

The MMU also recommends that, prior to estimating the default Avoidable Cost Rate (ACR) values for the next RPM Auction, the most current Handy-Whitman Index value be used to recalculate the ACR for the applicable year and the ten year annual average Handy-Whitman Index value be updated and used to recalculate the subsequent default ACR values.[8] The Tariff should be modified if necessary to implement this change. This will ensure an accurate calculation of the escalated ACR values which reflects actual Handy-Whitman Index results for prior years. PJM filed to implement this change recommended by the MMU, which became effective on February 5, 2013 for the 2016/2017 and subsequent Delivery Years.[9, 10]

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 7, the 164,561.2 MW of cleared resources for the entire RTO, which represented a reserve margin of 20.6 percent not considering Fixed Resource Requirement (FRR) load, resulted in net excess of 5,855.9 MW over the reliability requirement of 162,777.4 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-whole MW, total RPM market revenues for the 2015/2016 RPM Base Residual Auction were $9,734,336,627. If the VRR curves had not been reduced by the Short-Term Resource Procurement Target, total RPM market revenues for the 2015/2016 RPM Base Residual Auction would have been $12,386,531,361, an increase of $2,652,194,735, or 27 percent, compared to the actual results. The use of the Short-Term Resource Procurement Target resulted in a 21 percent reduction in RPM revenues for the 2015/2016 Base Residual Auction.

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8 See "Analysis of the 2013/2014 RPM Base Residual Auction Revised and Updated," <http://www.monitoringanalytics.com/reports/Reports/2010/Analysis_of_2013_2014_RPM_Base_Residual_Auction_20090920.pdf> (September 20, 2010).

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

10 See 142 FERC ¶ 61,092 (2013).

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 2015/2016 RPM Base Residual Auction were $9,734,336,627. If only generation and Annual DR were offered in the 2015/2016 RPM Base Residual Auction, total RPM market revenues for the 2015/2016 RPM Base Residual Auction would have been $13,636,817,993, an increase of $3,902,481,367, or 40 percent, compared to the actual results. The inclusion of the Limited and Extended Summer DR products resulted in a 29 percent reduction in RPM revenues for the 2015/2016 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 2015/2016 RPM Base Residual Auction were $9,734,336,627. 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 2015/2016 RPM Base Residual Auction, total RPM market revenues for the 2015/2016 RPM Base Residual Auction would have been $19,234,618,910, an increase of $9,500,282,283, or 98 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 49 percent reduction in RPM revenues for the 2015/2016 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 2015/2016 RPM Base Residual Auction were $9,734,336,627. If there were no offers for DR in the 2015/2016 RPM Base Residual Auction, total RPM market revenues for the 2015/2016 RPM Base Residual Auction would have been $23,457,546,624, an increase of $13,723,209,998, or 141 percent, compared to the actual results. The inclusion of Demand Resources resulted in a 59 percent reduction in RPM revenues for the 2015/2016 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 2015/2016 RPM Base Residual Auction were $9,734,336,627. If only generation and Annual DR were offered in the 2015/2016 RPM Base Residual Auction, total RPM market revenues for the 2015/2016 RPM Base Residual Auction would have been $13,636,817,993. If there were no offers for DR in the 2015/2016 RPM Base Residual Auction, total RPM market revenues for the 2015/2016 RPM Base Residual Auction would have been $23,457,546,624, an increase of $9,820,728,631, or 72 percent, compared to the results with only Annual DR. The inclusion of sell offers for Annual DR alone resulted in a 42 percent reduction in RPM revenues for the 2015/2016 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 42 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. In the 2015/2016 BRA, Extended Summer and Limited DR products also had a significant impact, 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.[11] 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 Maximum Achievable Control Technology (MACT) 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 8,882.5 MW of uncleared offers for generation resources, 2,777.8 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 2015/2016 RPM Base Residual Auction were $9,734,336,627. If the APIR associated with the pending environmental regulations which had not been previously submitted were removed, total RPM market revenues for the 2015/2016 RPM Base Residual Auction would have been $8,291,442,376, a reduction of $1,442,894,251, or 15 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 $1,442,894,251, or 17 percent.

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11 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2012," <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Report_Replacement_Capacity_Activity_20121211.pdf> (December 18, 2012).

Clearing Prices

Table 1 shows the clearing prices for Annual Resources in the 2015/2016 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), although the ATSI clearing price was approximately equal (99.7 percent) to net CONE.

Table 1 Clearing prices and net CONE: 2015/2016 RPM Base Residual Auction

LDA	Annual Clearing Price ($ per MW-day)	Net CONE ($ per MW-day)
RTO	$136.00	$320.63
MAAC	$167.46	$267.61
EMAAC	$167.46	$313.84
SWMAAC	$167.46	$267.61
PSEG	$167.46	$313.84
PSEG North	$167.46	$313.84
DPL South	$167.46	$313.84
Pepco	$167.46	$267.61
ATSI	$357.00	$358.22

Market Changes

RPM Market Design Changes

The 2015/2016 RPM Base Residual Auction was the second BRA conducted under the revised RPM rules effective January 31, 2011, related to the RPM must-offer requirement and market power mitigation.[12] 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.

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

12 134 FERC ¶ 61,065 (2011).

13 135 FERC ¶ 61,022 (2011).

Entry (CONE) for combined cycle (CC) and combustion turbine (CT) plants which is used as a benchmark value in assessing the competitiveness of a sell offer, 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]

The MOPR provides for a unit specific review by the MMU and PJM of sell offers for new resources and uprates that fall below the MOPR reference value. The reference value is 90 percent of the net CONE value for a combustion turbine or combined cycle unit. The reference value sets a standard that applies except in specific cases where the facts and circumstances of a particular project support a value lower than the reference value. The MMU conducted unit specific reviews of requests for exceptions to the MOPR reference value. When conducting unit specific reviews, the MMU applied the analytical approach used in the calculation of the gross CONE, which is used as an input to the VRR curve, and reviewed unit specific net revenue projections which offset gross CONE values. A critical difference between the MOPR definition of cost and the definition of net CONE is that net CONE uses the three year historical average net revenue for the reference unit while the MOPR definition includes projected net revenues. At times when forward market prices are well above historical prices, this difference can have a very significant impact on the calculation of unit specific net costs.[15] For example, the same unit used as the reference unit for gross CONE could have a net cost well below net CONE solely as a result of these differences in the net revenue offset. The impact on net CONE is larger for combined cycle units, which generally receive a larger share of gross CONE from net revenues than do combustion turbines, the gross CONE unit type used as an input parameter for the VRR curve.

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14 137 FERC ¶ 61,145 (2011). 139 FERC ¶ 61,011 (2012).

15 See 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).

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.[16] 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.[17] 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.[18] 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.

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,

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[16] 134 FERC ¶ 61,066 (2011).

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

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

Extended Summer and Limited simultaneously in a coupled offer. Only Demand Resources of different product types 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 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.[19,20] Capacity Market Sellers utilizing coupled sell offers cannot use the MPCE option. The intent of credit limited offers is to allow Capacity Market Sellers to better manage their credit requirement by specifying the maximum amount of credit they are willing to incur and to provide the service of determining the maximum cleared MW given the MPCE limit. For DR, 20

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

20 *See* PJM. "Manual 18:PJM Capacity Market ," Revision 17 (December 20, 2012) § 4.8.4.

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.[21] 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.

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. Effective January 31, 2012, the 2.5 percent holdback is not subtracted from the Minimum Annual and Extended Summer Resource Requirements.[22] The first auction affected was the 2015/2016 BRA. 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 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.

Other Changes Affecting Supply and Demand

On December 16, 2011, the U.S. Environmental Protection Agency (EPA) issued a final rule setting maximum achievable control technology (MACT) emissions standards for

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21 PJM. "Manual 18: PJM Capacity Market," Revision 16 (September 27, 2012), p. 74.

22 138 FERC ¶ 61,062 (2012).

hazardous air pollutants (HAP) from coal- and oil-fired electric utility steam generating units, pursuant to section 112(d) of the Clean Air Act.[23] The rule requires compliance by April 16, 2015.[24]

The MMU recognized that this rule, when proposed on March 16, 2011, constituted a significant step towards defining the regulatory obligations of capacity resources in the 2014/2015 Delivery Year. The MMU also stated that the cost of such investment, if adequately supported and documented, could be included in the calculated offer caps in the 2014/2015 RPM Base Residual Auction for resources that would be impacted by the rule if finalized substantially as proposed.[25, 26]

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

AEP Ohio and Duke Energy Ohio elected to participate in the 2015/2016 RPM Base Residual Auction. As a result, the Fixed Resource Requirement (FRR) obligation decreased 15,356.7 MW (51.6 percent) from 29,763.4 MW in the 2014/2015 BRA to 14,406.7 MW in the 2015/2016 BRA. This change also had an effect on supply, because resources formerly committed to these FRR plans and not excused were included in the supply curve for the 2015/2016 BRA.

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23 *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*, Final Rule, EPA Docket No. EPA-HQ-2009-0234, 77 Fed. Reg. 9304 (February 16, 2012).

24 *Id*. at 9465.

25 See MMU "ACR Data and Pending EPA Regulations" <http://www.monitoringanalytics.com/reports/Market_Messages/Messages/ACR_Data_and_Pending_EPA_Regulations_20110228.pdf> (February 28, 2011).

26 See MMU "ACR Data and Pending EPA Regulations" <http://www.monitoringanalytics.com/reports/Market_Messages/Messages/ACR_Data_and_Pending_EPA_Regulations_20110330.pdf> (March 30, 2011).

27 N.J.A.C. § 7:27–19.

The default Avoidable Cost Rate (ACR) values were adjusted from the levels used in the 2014/2015 BRA based on the most recent ten year annual average Handy-Whitman Index and the gross Cost of New Entry (CONE) values were adjusted using the most recent twelve month change in the Handy-Whitman Index. Given recent changes in the Handy Whitman Index values, the method used to adjust the ACR values resulted in overstating the ACR values for the 2015/2016 BRA.[28]

PJM filed to implement this change to the application of the Handy-Whitman Index recommended by the MMU, which became effective on February 5, 2013 for the 2016/2017 and subsequent Delivery Years.[29, 30]

Preliminary Market Structure Screen

Under the terms of the PJM Tariff effective for the BRA for the 2015/2016 Delivery Year, the MMU was required to apply the preliminary market structure screen (PMSS) prior to RPM Base Residual Auctions.[31] The purpose of the PMSS was to determine whether additional data are needed from owners of capacity resources in the defined areas in order to permit the application of market structure tests defined in the Tariff. For each LDA and the PJM Region, the PMSS was based on: (1) the unforced capacity available for the delivery year from Generation Capacity Resources located in such area; and (2) the LDA reliability requirements and the PJM reliability requirement.[32] The PMSS was applied separately for each LDA for which a separate VRR curve had been established by PJM for the delivery year.

An LDA or the Regional Transmission Organization (RTO) region failed the PMSS if any one of the following three screens was failed: (1) the market share of any capacity

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28 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).

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

30 See 142 FERC ¶ 61,092 (2013).

31 OATT Attachment M (PJM Market Monitoring Plan)-Appendix § II.D.1. The rules for PMSS were eliminated, effective December 17, 2012, by letter order in FERC Docket No. ER13-149 (November 28, 2012).

32 The terms "PJM Region," "RTO Region" and "RTO" are synonymous in this report and include all capacity within the PJM footprint.

resource owner exceeded 20 percent; (2) the Herfindahl-Hirschman Index (HHI) for all capacity resource owners was 1800 or higher; or (3) there were not more than three jointly pivotal suppliers.[33] Capacity resource owners who owned or controlled generation in the area that failed the PMSS and who intended to submit a non-zero sell offer price were required to provide Avoidable Cost Rate (ACR) data or a calculation of opportunity cost along with supporting documentation to the MMU.[34]

Consistent with the requirements of the Tariff, the MMU applied the PMSS 90 days prior to the 2015/2016 RPM Base Residual Auction.[35] As shown in Table 2, all LDAs and the entire PJM Region failed the PMSS. The RTO and MAAC passed the market share and HHI screens, but failed the three pivotal supplier screen. As a result, capacity resource owners were required to submit ACR data and PJM market revenues or opportunity cost data to the MMU for Existing Generation Capacity Resources for which they intended to submit non-zero sell offers unless certain other conditions were met.[36]

Table 2 Preliminary Market Structure Screen results: 2015/2016

RPM Markets	Highest Market Share	HHI	Pivotal Suppliers	Pass/Fail
RTO	14.3%	763	1	Fail
MAAC	17.5%	1114	1	Fail
EMAAC	32.6%	1904	1	Fail
SWMAAC	51.9%	4745	1	Fail
DPL South	49.2%	3257	1	Fail
PSEG	89.4%	8020	1	Fail
PSEG North	88.0%	7794	1	Fail
Pepco	94.1%	8876	1	Fail
ATSI	75.5%	5881	1	Fail

33 OATT Attachment M-Appendix § II.D.2.

34 OATT Attachment DD § 6.7 (b).

35 See "Preliminary Market Structure Screen Results for the 2015/2016 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2012/PMSS_Results_20152016_20120207.pdf> (February 7, 2012).

36 OATT Attachment DD § 6.7 (c).

MMU Methodology

The MMU reviewed the following inputs to and results of the 2015/2016 RPM Base Residual Auction: [37]

- **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 2009 through 2011;

- **Minimum Offer Price Rule (MOPR).** Reviewed unit specific requests for exceptions to the MOPR;

- **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 opportunity cost offers;

- **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, 2011 or reviewed requests for alternate maximum EFORds;

- **Clearing Prices.** Verified that the auction clearing prices were accurate, based on submitted offers,[38] the Variable Resource Requirement (VRR) curves, and the Minimum Resource Requirements;

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[37] 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 2015/2016 RPM Base Residual Auction.

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

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

Market Structure Tests

As shown in Table 3, all participants in the RTO, MAAC, and ATSI RPM markets failed the TPS test.[39] 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 38 Generation Capacity Resources, including 3,104.8 MW in the 2015/2016 RPM Base Residual Auction.

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.[40] 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.

Table 3 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

39 See the *2011 State of the Market Report for PJM* (March 15, 2012), 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.

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

owners have a reduced ability to unilaterally influence market price.[41] MAAC/EMAAC/SWMAAC/PSEG/PSEG North/DPL South/Pepco are presented together because EMAAC, SWMAAC, PSEG, PSEG North, DPL South, and Pepco were modeled but were not constrained LDAs in this auction.

Table 3 RSI Results: 2015/2016 RPM Base Residual Auction[42]

	$RSI_{1\ 1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
RTO	0.75	0.57	99	99
MAAC/EMAAC/SWMAAC/PSEG/PSEG North/DPL South/Pepco	0.49	0.63	12	12
ATSI	0.01	0.00	3	3

Offer Caps

The defined Generation Capacity Resource owners were required to submit ACR or opportunity cost data to the MMU by two months prior to the 2015/2016 RPM Base Residual Auction. Market power mitigation measures are applied to Existing Generation Capacity Resources such that the sell offer is set equal to the defined offer cap when the Capacity 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.[43] 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.[44] In effect, avoidable costs are the costs that a generation owner would not incur if the generating unit were mothballed for the year. 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

41 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.

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

43 OATT Attachment DD § 6.5.

44 OATT Attachment DD § 6.8 (b).

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.[45]

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 670 generation resources, of which 478 were based on the technology specific default (proxy) ACR values.[46] No generation resources elected to use the retirement ACR in the 2015/2016 BRA. The 2015/2016 default ACR values were escalated from the 2014/2015 default ACR values by PJM using the previously estimated base year values for 2014/2015 rather than incorporating the most recent Handy-Whitman Index value for 2011 in calculating the base year value. Unit-specific offer caps were calculated for 188 generation resources (16.1 percent) including 171 generation resources (14.6 percent) with an Avoidable Project Investment Recovery Rate (APIR) component and 17 generation resources (1.5 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 1,168 generation resources, 32 Planned Generation Capacity Resources had uncapped offers, 25 generation resources had uncapped planned uprates along with default ACR based offer caps calculated for the existing portion, seven generation resources had uncapped planned uprates along with price taker status for the existing portion, while the remaining 459 generation resources were price takers, of which the offers for 458 generation resources were zero and the offer for one generation resources was set to zero because no data were submitted.[47]

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45 OATT Attachment DD § 6.8 (a).

46 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.

47 Planned Generation Capacity Resources are subject to different market power mitigation rules than Existing Generation Capacity Resources. For RPM rules on mitigation, see OATT

As shown in Table **5**, the weighted average gross ACR for units with APIR ($401.95 per MW-day) and the weighted-average offer caps, net of net revenues, for units with APIR ($246.63 per MW-day) decreased from the 2014/2015 BRA values of $437.99 per MW-day and $274.45 per MW-day, due primarily to lower weighted average gross ACRs for oil and gas steam units, subcritical/supercritical coal units, and resources in the other category (diesel, pumped storage, hydro, waste coal) and offset by lower weighted-average net revenues.

The APIR component added an average of $238.79 per MW-day to the ACR value of the APIR units compared to $268.95 per MW-day in the 2014/2015 BRA.[48, 49] The highest APIR for a technology ($293.45 per MW-day) was for CTs. The maximum APIR effect ($776.46 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 $25.32 per MW-day to $17.86 per MW-day due primarily to higher weighted-average net revenues for units without an APIR component only partially offset by an increase in weighted-average gross ACRs.[50]

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.

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

49 The 171 resources which had an APIR component submitted $4.2 billion for capital projects associated with 26,344.3 MW of UCAP.

50 The default ACR values include an average APIR of $1.48 per MW-day, which is the average APIR ($1.42 per MW-day) for the previously estimated default ACR values in the 2014/2015 BRA escalated using the most recent Handy-Whitman Index value.

Table 4 ACR statistics: 2015/2016 RPM Base Residual Auction

Offer Cap/Mitigation Type	Number of Generation Resources Offered	Percent of Generation Resources Offered
Default ACR	449	38.4%
ACR data input (APIR)	171	14.6%
ACR data input (non-APIR)	17	1.5%
Opportunity cost	4	0.3%
Default ACR and opportunity cost	4	0.3%
Uncapped planned uprates and default ACR	25	2.1%
Uncapped planned uprates and opportunity cost	0	0.0%
Uncapped planned uprates and price taker	7	0.6%
Uncapped planned generation resources	32	2.7%
Existing generation resources as price takers	459	39.3%
Total Generation Capacity Resources offered	1,168	100.0%

Table 5 APIR statistics: 2015/2016 RPM Base Residual Auction[51, 52]

	Weighted-Average ($ per MW-day UCAP)					
	Combined Cycle	Combustion Turbine	Oil or Gas Steam	Subcritical/ Supercritical Coal	Other	Total
Non-APIR units						
ACR	$50.33	$36.07	$85.46	$232.16	$81.94	$113.51
Net revenues	$160.85	$34.32	$35.86	$248.90	$265.61	$148.07
Offer caps	$5.89	$11.34	$49.70	$26.50	$7.73	$17.86
APIR units						
ACR	$163.25	$334.57	$192.87	$471.60	$41.74	$401.95
Net revenues	$8.33	$17.93	$17.39	$221.10	$57.91	$166.81
Offer caps	$154.94	$316.69	$175.53	$264.18	$8.15	$246.63
APIR	$116.55	$293.45	$87.42	$265.13	$23.35	$238.79
Maximum APIR effect						$776.46

51 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.

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

Generation Capacity Resource Changes

As shown in Table 4, offers were submitted for 1,168 generation resources in the 2015/2016 RPM Base Residual Auction compared to 1,152 generation resources offered in the 2014/2015 RPM Base Residual Auction, or a net increase of 16 generation resources. This was a result of 111 additional generation resources offered offset by 95 fewer generation resources offered.

The 111 additional generation resources offered consisted of 49 new resources (6,221.0 MW), 45 resources that were previously entirely FRR committed (4,803.0 MW), 13 additional resources imported (1,072.2 MW), three resources that were excused and not offered in the 2014/2015 BRA (30.8 MW), and one Duke Energy Ohio and Kentucky (DEOK) integration resource not offered in the 2014/2015 BRA (42.7 MW).[53] The new Generation Capacity Resources consisted of 15 solar resources (13.8 MW), eight CT resources (1,348.4 MW), seven combined cycle resources (4,526.9 MW), six wind resources (104.9 MW), five diesel resources (13.6 MW), five hydroelectric resources (143.6 MW), two fuel cell resources (28.5 MW), and one steam unit (41.3 MW). In addition, there were the following new generation resources that were not offered in to the auction because they were either exported or entirely committed to FRR for the 2015/2016 Delivery Year: two CT resources (283.6 MW).

The 95 fewer generation resources offered consisted of 49 additional resources excused from offering (3,761.1 MW), 29 deactivated resources (3,713.2 MW), eight additional resources committed fully to FRR (471.8 MW), three less resources resulting from aggregation of RPM resources, three external resources not offered (866.4 MW), one resource that is no longer a PJM capacity resource (1.2 MW), one Planned Generation Capacity Resource not offered (1.5 MW), and one resource unoffered and unexcused (4.8 MW). In addition, there were the following retirements of resources that were either exported, excused, or committed to an FRR capacity plan in the 2014/2015 BRA: six steam units (918.5 MW). Table 6 shows Generation Capacity Resources for which deactivation requests have been submitted between the time of the 2014/2015 BRA and the 2015/2016 BRA.

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

Table 6 Generation Capacity Resource Deactivations

Resource Name	LDA	ICAP (MW)	Date Deactivation Notice Submitted	Projected Deactivation Date	Resource Name	LDA	ICAP (MW)	Date Deactivation Notice Submitted	Projected Deactivation Date
BURGER 3	RTO	31.0	03-Jun-11	01-Sep-11	GLEN GARDNER A-1	EMAAC	20.0	29-Feb-12	01-May-15
VINELAND 10	EMAAC	23.0	13-Jun-11	01-Sep-12	GLEN GARDNER A-2	EMAAC	20.0	29-Feb-12	01-May-15
VIKING SUNBURY NUG	MAAC	16.0	02-Jul-11	01-Mar-12	GLEN GARDNER A-3	EMAAC	20.0	29-Feb-12	01-May-15
POTOMAC RIVER 1	PEPCO	88.0	30-Aug-11	01-Oct-12	GLEN GARDNER A-4	EMAAC	20.0	29-Feb-12	01-May-15
POTOMAC RIVER 2	PEPCO	88.0	30-Aug-11	01-Oct-12	GLEN GARDNER B-5	EMAAC	20.0	29-Feb-12	01-May-15
POTOMAC RIVER 3	PEPCO	102.0	30-Aug-11	01-Oct-12	GLEN GARDNER B-6	EMAAC	20.0	29-Feb-12	01-May-15
POTOMAC RIVER 4	PEPCO	102.0	30-Aug-11	01-Oct-12	GLEN GARDNER B-7	EMAAC	20.0	29-Feb-12	01-May-15
POTOMAC RIVER 5	PEPCO	102.0	30-Aug-11	01-Oct-12	GLEN GARDNER B-8	EMAAC	20.0	29-Feb-12	01-May-15
CHESAPEAKE 1 DOM	RTO	111.0	15-Nov-11	31-Dec-14	NEW CASTLE 3	ATSI	93.0	29-Feb-12	16-Apr-15
CHESAPEAKE 2 DOM	RTO	111.0	15-Nov-11	31-Dec-14	NEW CASTLE 4	ATSI	92.0	29-Feb-12	16-Apr-15
YORKTOWN 1	RTO	159.0	15-Nov-11	31-Dec-14	NEW CASTLE 5	ATSI	140.0	29-Feb-12	16-Apr-15
BERGEN 3	PS-NORTH	21.0	01-Dec-11	01-Jun-15	NEW CASTLE DIESEL	ATSI	5.5	29-Feb-12	16-Apr-15
BURLINGTON 8	PSEG	21.0	01-Dec-11	01-Jun-15	NILES 1	ATSI	109.0	29-Feb-12	01-Oct-12
MERCER 3	PSEG	115.0	01-Dec-11	01-Jun-15	NILES 2	ATSI	108.0	29-Feb-12	01-Jun-12
NATIONAL PARK	PSEG	21.0	01-Dec-11	01-Jun-15	PORTLAND 1	MAAC	158.0	29-Feb-12	07-Jan-15
SEWAREN 6	PSEG	105.0	01-Dec-11	01-Jun-15	PORTLAND 2	MAAC	243.0	29-Feb-12	07-Jan-15
ARMSTRONG 1	RTO	172.0	26-Jan-12	01-Sep-12	SHAWVILLE 1	MAAC	122.0	29-Feb-12	16-Apr-15
ARMSTRONG 2	RTO	171.0	26-Jan-12	01-Sep-12	SHAWVILLE 2	MAAC	125.0	29-Feb-12	16-Apr-15
ASHTABULA	ATSI	210.0	26-Jan-12	01-Jun-15	SHAWVILLE 3	MAAC	175.0	29-Feb-12	16-Apr-15
BAYSHORE 2	RTO	120.0	26-Jan-12	01-Sep-12	SHAWVILLE 4	MAAC	175.0	29-Feb-12	16-Apr-15
BAYSHORE 3	RTO	119.0	26-Jan-12	01-Sep-12	TITUS 1	MAAC	81.0	29-Feb-12	16-Apr-15
BAYSHORE 4	RTO	180.0	26-Jan-12	01-Sep-12	TITUS 2	MAAC	81.0	29-Feb-12	16-Apr-15
EASTLAKE 1	ATSI	109.0	26-Jan-12	01-Jun-15	TITUS 3	MAAC	81.0	29-Feb-12	16-Apr-15
EASTLAKE 2	ATSI	109.0	26-Jan-12	01-Jun-15	CRAWFORD COAL 7	RTO	213.0	08-Mar-12	31-Dec-14
EASTLAKE 3	ATSI	109.0	26-Jan-12	01-Jun-15	CRAWFORD COAL 8	RTO	319.0	08-Mar-12	31-Dec-14
EASTLAKE 4	RTO	225.0	26-Jan-12	01-Sep-12	FISK COAL 19	RTO	326.0	08-Mar-12	31-Dec-12
EASTLAKE 5	RTO	597.0	26-Jan-12	01-Sep-12	AVON LAKE 7	ATSI	94.0	30-Mar-12	16-Apr-15
LAKESHORE	ATSI	190.0	26-Jan-12	01-Jun-15	AVON LAKE 9	ATSI	638.0	30-Mar-12	16-Apr-15
SMITH 3	RTO	28.0	26-Jan-12	01-Sep-12	CEDAR STATION CT 1	EMAAC	44.0	05-Apr-12	31-May-15
SMITH 4	RTO	87.0	26-Jan-12	01-Sep-12	CEDAR STATION CT 2	EMAAC	22.0	05-Apr-12	31-May-15
ALBRIGHT 1	RTO	73.0	08-Feb-12	01-Sep-12	DEEPWATER 1	EMAAC	78.0	05-Apr-12	31-May-15
ALBRIGHT 2	RTO	73.0	08-Feb-12	01-Sep-12	DEEPWATER 6	EMAAC	80.0	05-Apr-12	31-May-15
ALBRIGHT 3	RTO	137.0	08-Feb-12	01-Sep-12	MISSOURI AVE CT B	EMAAC	20.0	05-Apr-12	31-May-15
RIVESVILLE 5	RTO	35.0	08-Feb-12	01-Sep-12	MISSOURI AVE CT C	EMAAC	20.0	05-Apr-12	31-May-15
RIVESVILLE 6	RTO	86.0	08-Feb-12	01-Sep-12	MISSOURI AVE CT D	EMAAC	20.0	05-Apr-12	31-May-15
WILLOW ISLAND 1	RTO	51.0	08-Feb-12	01-Sep-12	HUTCHINGS 1	RTO	49.5	03-May-12	01-Jun-15
WILLOW ISLAND 2	RTO	138.0	08-Feb-12	01-Sep-12	HUTCHINGS 2	RTO	47.8	03-May-12	01-Jun-15
ELRAMA 1	RTO	93.0	29-Feb-12	01-Jun-12	SMART PAPER	RTO	24.9	14-May-12	10-Aug-12
ELRAMA 2	RTO	93.0	29-Feb-12	01-Jun-12					
ELRAMA 3	RTO	103.0	29-Feb-12	01-Jun-12					
ELRAMA 4	RTO	171.0	29-Feb-12	01-Oct-12					

RTO Market Results

Table 7 shows total RTO offer data for the 2015/2016 RPM Base Residual Auction. All MW values stated in the RTO section include all nested LDAs.[54,55] As shown in Table 9,

54 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.

55 Maps of the LDAs can be found in the *2011 State of the Market Report for PJM*, Appendix A, "PJM Geography."

total internal RTO unforced capacity (UCAP) increased 8,321.5 MW (4.2 percent) from 196,235.8 MW in the 2014/2015 RPM BRA to 204,557.3 MW.[56]

When comparing UCAP MW levels from one auction to another, two variables, capacity modifications and EFORd changes, need to be considered. The part of the net internal capacity change attributed 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 8,321.5 MW increase in internal capacity was a result of net generation capacity modifications (cap mods) (1,667.2 MW), net DR modifications (5,441.4 MW), net EE modifications (220.1 MW), the EFORd effect due to lower sell offer EFORds (938.4 MW), and the DR and EE effect due to a higher Load Management UCAP conversion factor (54.4 MW).[57,58]

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 2015/2016 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.[59] The ICAP of a unit

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

57 Similar to cap mods for generation resources, DR and EE mods include modifications (increases/decreases) to existing DR and EE resources and the creation of new DR or EE resources.

58 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 2014/2015 BRA, this conversion factor was 0.956*1.0809 = 1.0333. For the 2015/2016 BRA, this factor was 0.955*1.0859 = 1.0370. 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 PJM. "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 04 (June 1, 2011), p. 12-14.

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

may only be reduced through a cap mod if the capacity owner does not intend to restore the reduced capability by the end of the planning period following the planning period in question.[60] Otherwise the owner must take an outage, as appropriate, if the owner cannot provide energy consistent with the ICAP of the unit. Capacity, DR, 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, RPM capacity was 194,126.5 MW compared to 169,629.8 MW in the 2014/2015 RPM Base Residual Auction.[61] FRR volumes decreased by 15,835.2 MW primarily due to AEP Ohio and Duke Energy Ohio electing to participate in the 2015/2016 RPM Base Residual Auction, and imports increased by 340.0 MW. Of the 4,395.5 MW of imports, 460.2 MW were committed to an FRR capacity plan and 3,935.3 MW were offered in the auction, of which all 3,935.3 MW cleared. Of the cleared imports, 1,674.7 MW (42.6 percent) were from MISO. RPM capacity was reduced by exports of 1,214.2 MW, a decrease of 13.9 MW from the 2014/2015 RPM Base Residual Auction. Of total exports, 674.0 MW, 56 percent, were to the NYISO and 540.2 MW, 44 percent, were to MISO. In addition, RPM capacity was reduced by 288.2 MW of Planned Generation Capacity Resources which were not subject to the RPM must offer requirement and by 7,280.5 MW which were excused from the RPM must offer requirement, an increase of 6,686.4 MW from the 2014/2015 RPM Base Residual Auction. The excused Existing Generation Capacity Resources were the result of plans for retirement (7,183.6 MW), significant physical operational restrictions (43.6 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 (53.3 MW).[62] Subtracting 158.9 MW of FRR optional volumes not offered, a decrease of 1,929.1 MW from the 2014/2015 RPM Base Residual Auction, and 6,590.2 MW of DR and EE not offered, resulted in 178,594.5 MW that were available to be offered in the RPM Auction, an increase of 18,107.1 MW from the 2014/2015 RPM

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60 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."

61 The FRR alternative allows an 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.

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

Base Residual Auction.[63, 64] After accounting for the above, 6.8 MW were not offered in the RPM Auction.

Offered MW increased 18,101.4 MW from 160,486.3 MW to 178,587.7 MW, while the overall RTO Reliability Requirement adjusted for FRR obligations, from which the demand curve is developed, increased 14,454.3 MW from 148,323.1 MW to 162,777.4 MW.[65] 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.[66] The 14,454.3 MW increase in the RTO Reliability Requirement adjusted for FRR obligations from the 2014/2015 RPM Base Residual Auction was a result of a 15,356.7 MW decrease in the FRR obligation offset by a 902.4 MW decrease 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 decreased 1,589.6 MW from the 2014/2015 RPM Base Residual Auction to 163,168.0 MW. The 902.4 MW decrease in the RTO Reliability Requirement was a result of a 1,718.2 MW decrease in the forecast peak load in UCAP terms holding the FPR constant at the 2014/2015 level offset by a 815.8 MW increase attributable to the change in the FPR.

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 result in order to procure the defined minimum resource requirements for the Extended

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63 FRR entities are allowed to offer in the RPM Auction excess volumes above their FRR quantities, subject to a sales cap amount. The 158.9 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.

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

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

66 PJM. "Reliability Assurance Agreement among Load-Serving Entities in the PJM Region," Schedule 4.1.

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 the RTO in the 2015/2016 BRA. This means that the auction clearing mechanism resulted in a higher price for Extended Summer and Annual Resources. Higher priced Extended Summer Resources were required in order to meet the minimum reliability requirement for such resources. As shown in Figure 1, the resource clearing price for Limited Resources for the RTO was $118.54 per MW-day, the resource clearing price for Extended Summer and Annual Resources for the RTO was $136.00 per MW-day. Annual Resources contribute to meeting the Minimum Extended Summer Resource Requirement, so both Annual Resources and Extended Summer DR received the higher price.

The final 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. Effective with the 2012/2013 Delivery Year, the final zonal capacity price and the final CTR credit rate are calculated after the final incremental auction. As shown in Table 7, the preliminary net load price is $134.62 per MW-day in the RTO.

As shown in Table 7, the cleared and make-whole MW of 164,563.9 for the entire RTO, which represented a reserve margin of 20.6 percent, resulted in net excess of 5,855.9 MW over the reliability requirement of 162,777.4 MW (Installed Reserve Margin (IRM) of 15.4 percent). [67,68] Net excess increased 383.6 MW from the net excess of 5,472.3 MW in the 2014/2015 RPM Base Residual Auction. As shown in Figure 1, the vertical Minimum Extended Summer Resource Requirement resulted in a clearing price for Annual and Extended Summer resources of $136.00 per MW-day, and the downward sloping VRR demand curve resulted in a clearing price for Limited Resources of $118.54 per MW-day.

If the market clears on a nonflexible supply segment, a sell offer that specifies a minimum block MW value greater than zero, the Capacity Market Seller will be assigned make-whole MW equal to the difference between the sell offer minimum block

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[67] 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.

[68] The IRM increased from 15.3 percent in the 2014/2015 RPM Base Residual Auction to 15.4 percent in the 2015/2016 RPM Base Residual Auction.

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.[69] 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.[70] The market results in the 2015/2016 BRA included 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.[71,72] 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.[73] The market results in the 2015/2016 BRA did not include make-whole MW or payments related to NEPA or Multi-Year Pricing Option.

Table 10 shows cleared MW by zone and fuel source. Of the 167,691.1 MW offered for generation resources, 148,805.9 MW cleared (94.4 percent). Of the 164,561.2 cleared MW in the entire RTO, 25,789.2 MW (15.7 percent) cleared in ComEd, followed by 24,633.4 MW in Dominion (15.0 percent) and 15,073.9 MW (9.2 percent) in AEP. Of the 148,805.9 cleared MW for generation resources in the entire RTO, 53,414.3 MW (35.9 percent) were gas resources, followed by 47,115.6 MW (31.7 percent) from coal resources and 30,702.8 MW (20.6 percent) from nuclear resources.

The 14,023.8 MW uncleared MW in the entire RTO were the result of offer prices which exceeded the clearing prices. Of the 14,023.8 uncleared MW in the entire RTO, 17.8 MW were EE offers, 5,123.5 MW were DR offers, and the remaining 8,882.5 MW were generation offers. Table 11 presents details on the generation offers that did not clear. Of the 8,882.5 MW of uncleared generation offers, 3,915.3 MW (44.1 percent) were for generation resources greater than 40 years old, and 4,967.2 MW (55.9 percent) were for generation resources less than or equal to 40 years old. Of the 8,882.5 MW of uncleared offers for generation resources, 2,777.8 MW were offers for resources including costs

69 OATT Attachment DD § 5.14 (b).

70 OATT Attachment DD § 5.12 (a).

71 OATT Attachment DD § 5.14 (c) (2).

72 OATT Attachment DD § 6.8 (a).

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

associated with environmental regulation compliance that were not previously included in APIR.

Table 12 shows the auction results in the prior two delivery years for the generation resources that did not clear some or all MW in the 2015/2016 BRA. Of the 77 generation resources that did not clear 8,882.5 MW in the 2015/2016 BRA, 14 of those generation resources did not clear 2,438.7 MW in the 2014/2015 Delivery Year. Of those 14 generation resources that did not clear MW in the 2015/2016 and 2014/2015 Delivery Years, 5 of those generation resources did not clear 595.3 MW in the 2013/2014 Delivery Year. Thus, 2,438.7 MW of capacity did not clear in two subsequent auctions, but this did not extend to three subsequent 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.[74] 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.[75]

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

[74] PJM. “Manual 14B: PJM Region Transmission Planning Process, Attachment C: PJM Deliverability Testing Methods,” Revision 22 (October 25, 2012), p. 53. Manual 14B indicates that all “electrically cohesive load areas” are tested.

[75] PJM. “Manual 18: PJM Capacity Market,” Revision 16 (September 27, 2012), p. 11.

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.[76] 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."[77] 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 13 shows the CETL and CETO values used in the 2015/2016 study compared to the 2014/2015 values. The increase in CETL for the MAAC, SWMAAC, and Pepco LDAs is mainly due to several RTEP projects which add reactive support at the Loudon, Pleasant View, and Doubs 500 kV substations and the rebuild of the Mount Storm-Doubs 500 kV line.[78] The increase in CETL for the PSEG and PSEG North LDAs was attributable to the 138 kV to 230 kV conversions of circuits between Roseland and Hudson. The increase in CETL for the EMAAC LDA is mainly due to the addition of the PPL portion of the Susquehanna-Roseland 500 kV line. The ATSI LDA was not modeled in the 2014/2015 BRA, because the CETL to CETO ratio was greater than the 1.15 threshold. In the 2015/2016 model, the CETL to CETO ratio for the ATSI LDA was less than the 1.15 threshold due to the increase in CETO as a result of the pending deactivations of over 2,000 MW.

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

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76 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.

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

78 See PJM "Updated 2015/2016 RPM Base Residual Auction Planning Period Parameters," <http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2015-2016-planning-period-parameters-report.ashx> (April 6, 2012).

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.

There were two locationally binding constraints in the 2015/2016 BRA which resulted in demand clearing in the locationally constrained LDA 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 total 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.

The CETL values for MAAC, EMAAC, SWMAAC, PSEG, PSEG North, and Pepco used in the 2015/2016 RPM Base Residual Auction were significantly higher than the values used in the 2014/2015 RPM Base Residual Auction. The CETL values for DPL South used in the 2015/2016 RPM Base Residual Auction were slightly lower than the values used in the 2014/2015 RPM Base Residual Auction.

Composition of the Steeply Sloped Portion of the Supply Curve

Table 14 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 $813.38 per MW-day. Offers for DR and EE resources were 28.5 percent of the offers greater than $35.00 per MW-day. Oil or gas steam, combustion turbines and subcritical/supercritical coal units made up 59.4 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 2015/2016 BRA, the 2.5 percent reduction resulted in the removal of 4,069.4 MW from the RTO demand curve.[79] 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 15 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 MAAC Minimum Extended Summer Resource Requirement would have been binding. The RTO clearing price for Limited Resources would have increased to $165.39 per MW-day, and the clearing quantity would have decreased to 12,292.2 MW. The RTO clearing price for Extended Summer and Annual Resources would have increased to $166.00 per MW-day, and the clearing quantity would have increased to 155,315.7 MW. The MAAC clearing price for Limited Resources would have increased to $189.06 per MW-day, and the clearing quantity would have increased to 5,102.3 MW. The MAAC clearing price for Extended Summer and Annual Resources would have increased to $200.00 per MW-day, and the clearing quantity would have increased to 61,854.5 MW. The ATSI clearing price for Limited Resources would have increased to $415.11 per MW-day, and the clearing quantity would have increased to 693.5 MW. The ATSI clearing price for Extended Summer would have increased to $415.72 per MW-day, and the clearing quantity would have decreased to 813.1 MW. The ATSI clearing price for Annual Resources would have increased to $537.33 per MW-day, and the clearing quantity would have increased to 9,227.0 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 2015/2016 RPM Base Residual Auction were $9,734,336,627. If the VRR curves had not been reduced by the Short-Term Resource Procurement Target, total RPM market revenues for the 2015/2016 RPM Base Residual Auction would have been $12,386,531,361, an increase of $2,652,194,735, or 27 percent, compared to the actual

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

results. The use of the Short-Term Resource Procurement Target resulted in a 21 percent reduction in RPM revenues for the 2015/2016 Base Residual Auction.

The MMU recommends that the use of the 2.5 percent demand adjustment be terminated immediately. 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 2015/2016 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.

Demand Side Resources in RPM

There are two categories of demand side products included in the RPM market design for the 2015/2016 BRA:[80,81]

- **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)

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80 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.

81 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.

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.[82] The Energy Efficiency (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.[83]

Effective with the 2014/2015 Delivery Year, there are three types of Demand Resource products incorporated in the RPM market design:[84, 85]

- **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 16 shows offered and cleared capacity from Demand Resources and Energy Efficiency Resources in the 2015/2016 RPM Base Residual Auction compared to the

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82 "Reliability Assurance Agreement among Load-Serving Entities in the PJM Region," Schedule 6, Section M.

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

84 134 FERC ¶ 61,066 (2011).

85 "Reliability Assurance Agreement among Load-Serving Entities in the PJM Region," Article 1.

2014/2015 RPM Base Residual Auction. Offers for DR increased from 15,545.6 MW in the 2014/2015 BRA to 19,956.3 MW in the 2015/2016 BRA, an increase of 4,410.7 or 28.4 percent.

Table 17 shows offered and cleared MW for Demand Resources by LDA and offer/product type in the 2015/2016 RPM Base Residual Auction. Of the 8,399.7 MW of non-coupled DR offers, 6,535.6 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 about 7,000-8,000 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 a higher price, reflecting the fact that such a product has higher costs.

Table 18 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 rules.

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 19 shows the results if only generation and Annual DR were offered in the 2015/2016 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 RTO clearing price would have increased to $220.00 per MW-day, and the clearing quantity would have decreased to 162,323.0 MW. The MAAC import limit would not have been a binding constraint. The ATSI clearing price would have increased to $358.22 per MW-day, and the clearing quantity would have decreased to 10,562.0 MW.

Based on actual auction clearing prices and quantities and make-whole MW, total RPM market revenues for the 2015/2016 RPM Base Residual Auction were $9,734,336,627. If only generation and Annual DR were offered in the 2015/2016 RPM Base Residual Auction, total RPM market revenues for the 2015/2016 RPM Base Residual Auction would have been $13,363,817,993, an increase of $3,902,481,367, or 40 percent, compared to the actual results. The inclusion of the Limited and Extended Summer DR products resulted in a 29 percent reduction in RPM revenues for the 2015/2016 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. 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 is 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 20 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 2015/2016 RPM Base Residual Auction and everything else had remained the same. The RTO clearing price would have increased to $313.43 per MW-day, and the clearing quantity would have decreased to 164,335.8 MW. The MAAC import limit would not have been a binding constraint. The ATSI clearing price would have increased to $313.43 per MW-day, and the clearing quantity would have increased to 10,758.5 MW.

Based on actual auction clearing prices and quantities and make-whole MW, total RPM market revenues for the 2015/2016 RPM Base Residual Auction were $9,734,336,627. 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 2015/2016 RPM Base Residual Auction, total RPM market revenues for the 2015/2016 RPM Base Residual Auction would have been $19,234,618,910, an increase of $9,500,282,283, or 98 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 49 percent reduction in RPM revenues for the 2015/2016 Base Residual Auction.

Impact of DR

Table 21 shows the results if there were no offers for DR in the 2015/2016 RPM Base Residual Auction and everything else had remained the same. The RTO clearing price would have increased to $401.42 per MW-day, and the clearing quantity would have decreased to 156,381.4 MW. The MAAC import limit would not have been a binding constraint. The ATSI clearing price would have increased to $537.33 per MW-day, and the clearing quantity would have decreased to 9,690.5 MW.

Based on actual auction clearing prices and quantities and make-whole MW, total RPM market revenues for the 2015/2016 RPM Base Residual Auction were $9,734,336,627. If there were no offers for DR in the 2015/2016 RPM Base Residual Auction, total RPM market revenues for the 2015/2016 RPM Base Residual Auction would have been $23,457,546,624, an increase of $13,723,209,998, or 141 percent, compared to the actual results. The inclusion of Demand Resources resulted in a 59 percent reduction in RPM revenues for the 2015/2016 Base Residual Auction.

Impact of Environmental Regulation Compliance

On December 16, 2011, the U.S. Environmental Protection Agency (EPA) issued 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.[86] The rule requires compliance by April 16, 2015.[87]

The MMU recognized that this rule, when proposed on March 16, 2011, constituted a significant step towards defining the regulatory obligations of capacity resources in the 2014/2015 Delivery Year. The MMU also stated that the cost of such investment, if adequately supported and documented, could be included in the calculated offer caps in the 2014/2015 RPM Base Residual Auction for resources that would be impacted by the rule if finalized substantially as proposed.[88,89]

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

Table 22 shows the results if the APIR associated with environmental regulation compliance, which were not previously submitted, were removed. The RTO Minimum Extended Summer Resource Requirement would not have been a binding constraint. The RTO clearing price for Limited, Extended Summer, and Annual Resources would have decreased to $122.22 per MW-day, and the clearing quantity would have decreased to 164,292.6 MW. The MAAC import limit would not have been a binding constraint. The ATSI Minimum Annual Resource Requirement would not have been a binding constraint. The ATSI clearing price for Limited and Extended Summer Resources would

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86 *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*, Final Rule, EPA Docket No. EPA-HQ-2009-0234, 77 Fed. Reg. 9304 (February 16, 2012).

87 *Id*. at 9465.

88 See MMU "ACR Data and Pending EPA Regulations," <http://www.monitoringanalytics.com/reports/Market_Messages/Messages/ACR_Data_and_Pending_EPA_Regulations_20110228.pdf> (February 28, 2011).

89 See MMU "ACR Data and Pending EPA Regulations," <http://www.monitoringanalytics.com/reports/Market_Messages/Messages/ACR_Data_and_Pending_EPA_Regulations_20110330.pdf> (March 30, 2011).

90 N.J.A.C. § 7:27–19.

have increased to $357.00 per MW-day, and the clearing quantity would have increased to 1,914.9 MW. The ATSI clearing price for Annual Resources would have remained the same at $357.00 per MW-day, and the clearing quantity would have decreased to 8,651.6 MW.

Based on actual auction clearing prices and quantities and make-whole MW, total RPM market revenues for the 2015/2016 RPM Base Residual Auction were $9,734,336,627. If the APIR associated with the pending environmental regulations which were not previously submitted were removed, total RPM market revenues for the 2015/2016 RPM Base Residual Auction would have been $8,291,442,376, a reduction of $1,442,894,251, or 15 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 $1,442,894,251, or 17 percent.

Tables and Figures for RTO Market

Table 7 RTO offer statistics: 2015/2016 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	187,547.9	176,713.7		
DR capacity	25,833.7	26,790.4		
EE capacity	1,016.6	1,053.2		
Total internal RTO capacity	214,398.2	204,557.3		
FRR	(15,997.9)	(14,826.3)		
Imports	4,649.7	4,395.5		
RPM capacity	203,050.0	194,126.5		
Exports	(1,218.8)	(1,214.2)		
FRR optional	(177.8)	(158.9)		
Excused Existing Generation Capacity Resources	(8,712.9)	(7,280.5)		
Unoffered Planned Generation Capacity Resources	(298.5)	(288.2)		
Unoffered DR and EE	(6,354.8)	(6,590.2)		
Available	186,287.2	178,594.5	100.0%	100.0%
Generation offered	166,127.8	157,691.1	89.2%	88.3%
DR offered	19,243.6	19,956.3	10.3%	11.2%
EE offered	907.8	940.3	0.5%	0.5%
Total offered	186,279.2	178,587.7	100.0%	100.0%
Unoffered Existing Generation Capacity Resources	8.0	6.8	0.0%	0.0%
Cleared in RTO		157,458.5		88.2%
Cleared in LDAs		7,102.7		4.0%
Total cleared		164,561.2		92.1%
Make-whole		2.7		0.0%
Uncleared generation		8,882.5		5.0%
Uncleared DR		5,123.5		2.9%
Uncleared EE		17.8		0.0%
Total uncleared		14,023.8		7.9%
Reliability requirement		162,777.4		
Total cleared plus make-whole		164,563.9		
Short-Term Resource Procurement Target		4,069.4		
Net excess/(deficit)		5,855.9		
Resource clearing price for Limited Resources ($ per MW-day)		$118.54		
Resource clearing price for Extended Summer Resources ($ per MW-day)		$136.00		
Resource clearing price for Annual Resources ($ per MW-day)		$136.00		
Preliminary zonal capacity price ($ per MW-day)		$134.62	A	
Base zonal CTR credit rate ($ per MW-day)		$0.00	B	
Preliminary net load price ($ per MW-day)		$134.62	A-B	

Table 8 Capacity modifications (ICAP): 2015/2016 RPM Base Residual Auction[91]

	ICAP (MW)		
	RTO	MAAC	ATSI
Generation increases	11,254.0	3,926.2	922.0
Generation decreases	(10,047.6)	(844.3)	0.0
Capacity modifications net increase/(decrease)	1,206.4	3,081.9	922.0
DR increases	18,132.9	8,352.2	2,635.7
DR decreases	(12,907.3)	(8,510.9)	(1.7)
DR modifications increase/(decrease)	5,225.6	(158.7)	2,634.0
EE increases	600.9	123.3	75.5
EE decreases	(390.8)	(96.0)	0.0
EE modifications increase/(decrease)	210.1	27.3	75.5
Net internal capacity increase/(decrease)	6,642.1	2,950.5	3,631.5

[91] Only cap mods, DR mods, and EE mods that had a start date on or before June 1, 2015 are included.

Table 9 Capacity modifications (UCAP): 2015/2016 RPM Base Residual Auction

	UCAP (MW)		
	RTO	MAAC	ATSI
Generation increases	10,496.2	3,759.5	918.2
Generation decreases	(8,829.0)	(633.6)	0.0
Capacity modifications net increase/(decrease)	1,667.2	3,125.9	918.2
DR increases	18,780.7	8,646.2	2,730.8
DR decreases	(13,339.3)	(8,795.8)	(1.8)
DR modifications increase/(decrease)	5,441.4	(149.6)	2,729.0
EE increases	622.2	127.5	78.2
EE decreases	(402.1)	(98.1)	0.0
EE modifications increase/(decrease)	220.1	29.4	78.2
Net capacity/DR/EE modifications increase/(decrease)	7,328.7	3,005.7	3,725.4
EFORd effect	938.4	508.9	133.6
DR and EE effect	54.4	29.5	3.3
Net internal capacity increase/(decrease)	8,321.5	3,544.1	3,862.3

Table 10 Cleared MW by zone and resource type/fuel source: 2015/2016 RPM Base Residual Auction[92]

	Cleared UCAP (MW)										
Zone	DR	EE	Coal	Gas	Hydroelectric	Nuclear	Oil	Solar	Solid Waste	Wind	Total
AECO	207.9	1.2	680.9	1,284.2	0.0	0.0	176.1	13.3	0.0	0.0	2,363.6
AEP	1,684.4	213.9	6,312.7	6,595.0	82.1	0.0	0.0	0.0	0.0	185.8	15,073.9
AP	935.5	0.8	5,179.5	2,379.7	113.7	0.0	0.0	0.0	0.0	136.9	8,746.1
ATSI	1,763.7	44.9	4,525.0	2,130.5	0.0	2,012.7	190.8	0.0	0.0	0.0	10,667.6
BGE	1,141.7	103.6	747.7	469.5	0.0	1,694.9	652.6	0.0	54.1	0.0	4,864.1
ComEd	1,698.2	422.4	4,495.5	8,686.8	0.0	9,948.2	210.5	0.0	0.0	327.6	25,789.2
DAY	196.9	2.0	2,549.7	1,292.5	108.4	0.0	55.6	0.4	0.0	0.0	4,205.5
DEOK	278.9	4.6	2,267.4	57.6	0.0	0.0	259.0	0.0	0.0	0.0	2,867.5
DLCO	244.7	4.1	626.2	225.2	0.0	1,741.0	11.1	0.0	0.0	0.0	2,852.3
Dominion	1,381.8	7.2	5,362.0	9,058.9	3,547.2	3,476.7	1,608.0	3.2	188.4	0.0	24,633.4
DPL	433.5	15.5	392.0	3,076.6	0.0	0.0	918.6	0.0	0.0	0.0	4,836.2
EXT	0.0	0.0	2,844.8	824.9	253.3	12.3	0.0	0.0	0.0	0.0	3,935.3
JCPL	350.2	0.0	0.0	2,893.3	394.9	584.1	309.6	7.7	8.8	0.0	4,548.6
Met-Ed	348.6	3.4	111.3	2,054.3	18.2	801.8	212.2	0.0	72.0	0.0	3,621.8
PECO	801.8	14.8	0.0	3,299.6	1,621.3	4,546.4	766.9	0.9	98.2	0.0	11,149.9
PENELEC	525.6	3.4	4,564.9	305.0	489.6	0.0	60.8	0.0	40.4	115.2	6,104.9
Pepco	867.4	55.8	2,257.9	1,528.7	0.0	0.0	1,376.2	0.0	49.7	0.0	6,135.7
PPL	1,155.0	14.2	3,589.5	2,112.1	703.3	2,486.0	1,911.3	0.0	14.0	30.8	12,016.2
PSEG	796.1	10.7	608.6	5,139.9	2.1	3,398.7	0.0	30.7	141.7	0.0	10,128.5
RECO	20.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.9
Total	14,832.8	922.5	47,115.6	53,414.3	7,334.1	30,702.8	8,719.3	56.2	667.3	796.3	164,561.2

Table 11 Uncleared generation offers by technology type and age: 2015/2016 RPM Base Residual Auction

	Uncleared UCAP (MW)	
Technology Type	Less Than or Equal to 40 Years Old	Greater than 40 Years Old
Combined cycle	699.9	0.0
Combustion turbine	2,355.7	445.6
Oil or gas steam	126.6	360.7
Subcritical/supercritical coal	1,781.7	3,109.0
Other	3.3	0.0
Total	4,967.2	3,915.3

92 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, 3,398.7 MW of the 10,128.5 cleared MW in the PSEG Zone were modeled and cleared in the EMAAC LDA.

Table 12 Uncleared generation resources in multiple auctions

Technology	2015/2016 Uncleared UCAP (MW)	Number of Resources	2014/2015 Results for Same Set of Resources Uncleared UCAP (MW)	Number of Resources	2013/2014 Results for Same Set of Resources Uncleared UCAP (MW)	Number of Resources
Combined cycle	699.9	9	0.0	0	0.0	0
Combustion turbine	2,801.3	44	185.7	4	0.0	0
Oil or gas steam	487.3	9	320.1	5	283.5	4
Subcritical/supercritical coal	4,890.7	13	1,932.9	5	311.8	1
Other	3.3	2	0.0	0	0.0	0
Total	8,882.5	77	2,438.7	14	595.3	5

Table 13 PJM LDA CETL and CETO Values: 2014/2015 and 2015/2016 RPM Base Residual Auctions

	2014/2015			2015/2016			Change			
			CETL to CETO			CETL to CETO	CETO		CETL	
LDA	CETO	CETL	Ratio	CETO	CETL	Ratio	MW	Percentage	MW	Percentage
MAAC	2,020.0	5,694.0	282%	100.0	6,156.0	6156%	(1,920.0)	(95%)	462.0	8%
EMAAC	5,790.0	8,189.0	141%	3,860.0	9,177.0	238%	(1,930.0)	(33%)	988.0	12%
SWMAAC	5,420.0	7,718.5	142%	4,720.0	8,373.0	177%	(700.0)	(13%)	654.5	8%
PSEG	4,880.0	5,720.7	117%	4,600.0	6,220.0	135%	(280.0)	(6%)	499.3	9%
PSEG North	2,110.0	2,372.0	112%	2,240.0	2,972.0	133%	130.0	6%	600.0	25%
DPL South	1,410.0	1,925.0	137%	1,510.0	1,822.0	121%	100.0	7%	(103.0)	(5%)
Pepco	3,500.0	5,606.3	160%	3,380.0	6,522.0	193%	(120.0)	(3%)	915.7	16%
ATSI	3,670.0	>4221.0	>115%	5,280.0	5,417.8	103%	1,610.0	44%	NA	NA

Table 14 Offers greater than $35.00 per MW-day on total RTO supply curve: 2015/2016 RPM Base Residual Auction[93]

Technology/Resource Type	Offered UCAP (MW)	Percent of Offers
Subcritical/supercritical coal	13,986.4	36.0%
Demand Resource coupled	6,879.0	17.7%
Combined cycle	4,658.4	12.0%
Oil or gas steam	4,588.7	11.8%
Combustion turbine	4,548.9	11.7%
Demand Resource non-coupled	4,212.3	10.8%
Other generation	28.8	0.1%
Energy Efficiency Resource	2.3	0.0%
Total	38,904.8	100.0%

93 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 15 Impact of Short-Term Resource Procurement Target: 2015/2016 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	$118.54	9,247.2	$165.39	12,292.2
	Extended Summer	$136.00	5,202.3	$166.00	3,201.2
	Annual	$136.00	150,111.7	$166.00	152,114.5
MAAC	Limited	$150.00	3,936.1	$189.06	5,102.3
	Extended Summer	$167.46	2,677.9	$200.00	1,684.0
	Annual	$167.46	59,176.4	$200.00	60,170.5
ATSI	Limited	$304.62	604.8	$415.11	693.5
	Extended Summer	$322.08	836.3	$415.72	813.1
	Annual	$357.00	9,226.5	$537.33	9,227.0

Table 16 DR and EE statistics by LDA: 2014/2015 and 2015/2016 RPM Base Residual Auctions[94]

		2014/2015 BRA		2015/2016 BRA		Change in UCAP	
LDA		ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)	MW	Percentage
RTO	DR offered	15,043.1	15,545.6	19,243.6	19,956.3	4,410.7	28.4%
RTO	EE offered	806.5	831.9	907.8	940.3	108.4	13.0%
RTO	DR cleared	13,663.8	14,118.4	14,303.2	14,832.8	714.4	5.1%
RTO	EE cleared	796.9	822.1	890.8	922.5	100.4	12.2%
MAAC	DR offered	8,140.7	8,413.8	8,835.9	9,163.3	749.5	8.9%
MAAC	EE offered	201.8	207.6	229.1	237.2	29.6	14.3%
MAAC	DR cleared	7,003.5	7,236.8	6,411.4	6,648.7	(588.1)	(8.1%)
MAAC	EE cleared	193.9	199.6	215.3	222.6	23.0	11.5%
EMAAC	DR offered	3,353.5	3,466.6	3,736.6	3,874.9	408.3	11.8%
EMAAC	EE offered	24.9	25.1	48.9	50.5	25.4	101.2%
EMAAC	DR cleared	2,774.5	2,866.8	2,517.2	2,610.4	(256.4)	(8.9%)
EMAAC	EE cleared	20.7	20.9	40.9	42.2	21.3	101.9%
SWMAAC	DR offered	2,393.7	2,473.4	2,212.6	2,295.2	(178.2)	(7.2%)
SWMAAC	EE offered	157.3	162.6	154.2	159.8	(2.8)	(1.7%)
SWMAAC	DR cleared	2,162.1	2,234.4	1,937.2	2,009.1	(225.3)	(10.1%)
SWMAAC	EE cleared	156.0	161.3	153.8	159.4	(1.9)	(1.2%)
DPL South	DR offered	253.7	262.3	127.2	131.9	(130.4)	(49.7%)
DPL South	EE offered	5.0	5.0	0.0	0.0	(5.0)	(100.0%)
DPL South	DR cleared	213.9	220.9	83.2	86.3	(134.6)	(60.9%)
DPL South	EE cleared	5.0	5.0	0.0	0.0	(5.0)	(100.0%)
PSEG	DR offered	1,102.7	1,140.1	1,043.2	1,081.9	(58.2)	(5.1%)
PSEG	EE offered	6.8	6.8	11.6	11.9	5.1	75.0%
PSEG	DR cleared	933.0	964.2	767.6	796.1	(168.1)	(17.4%)
PSEG	EE cleared	4.8	4.8	10.4	10.7	5.9	122.9%
PSEG North	DR offered	479.8	496.2	353.3	366.5	(129.7)	(26.1%)
PSEG North	EE offered	0.0	0.0	3.4	3.5	3.5	NA
PSEG North	DR cleared	429.1	443.3	253.8	263.3	(180.0)	(40.6%)
PSEG North	EE cleared	0.0	0.0	3.0	3.1	3.1	NA
Pepco	DR offered	989.9	1,022.5	931.7	966.4	(56.1)	(5.5%)
Pepco	EE offered	41.8	43.3	54.2	56.2	12.9	29.8%
Pepco	DR cleared	864.3	893.1	836.3	867.4	(25.7)	(2.9%)
Pepco	EE cleared	41.4	42.9	53.8	55.8	12.9	30.1%
ATSI	DR offered	1,021.1	1,055.1	1,965.7	2,038.5	983.4	93.2%
ATSI	EE offered	3.0	3.0	46.5	48.1	45.1	1,503.3%
ATSI	DR cleared	925.0	955.7	1,700.8	1,763.7	808.0	84.5%
ATSI	EE cleared	2.7	2.7	43.3	44.9	42.2	1,563.0%

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

Table 17 Offered and cleared DR by LDA and offer/product type: 2015/2016 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	65.9	0.0	0.0	63.3	0.0	0.0
RTO	Non-coupled	Extended Summer	0.0	1,798.2	0.0	0.0	512.3	0.0
RTO	Non-coupled	Limited	0.0	0.0	6,535.6	0.0	0.0	4,475.5
RTO	Coupled	Annual and Extended Summer	0.0	0.0	0.0	0.0	0.0	0.0
RTO	Coupled	Annual and Limited	28.5	0.0	80.3	0.0	0.0	80.3
RTO	Coupled	Extended Summer and Limited	0.0	3,341.5	3,415.8	0.0	2,393.6	80.1
RTO	Coupled	Annual, Extended Summer, and Limited	7,277.5	7,918.4	8,059.8	320.0	2,296.4	4,611.3
MAAC	Non-coupled	Annual	34.7	0.0	0.0	34.7	0.0	0.0
MAAC	Non-coupled	Extended Summer	0.0	1,136.7	0.0	0.0	445.3	0.0
MAAC	Non-coupled	Limited	0.0	0.0	3,262.2	0.0	0.0	2,068.0
MAAC	Coupled	Annual and Extended Summer	0.0	0.0	0.0	0.0	0.0	0.0
MAAC	Coupled	Annual and Limited	24.3	0.0	65.3	0.0	0.0	65.3
MAAC	Coupled	Extended Summer and Limited	0.0	1,348.5	1,348.5	0.0	1,120.5	8.1
MAAC	Coupled	Annual, Extended Summer, and Limited	2,767.8	3,232.7	3,315.3	0.0	1,112.1	1,794.7
ATSI	Non-coupled	Annual	5.2	0.0	0.0	2.6	0.0	0.0
ATSI	Non-coupled	Extended Summer	0.0	66.3	0.0	0.0	2.1	0.0
ATSI	Non-coupled	Limited	0.0	0.0	530.7	0.0	0.0	460.1
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	292.0	299.8	0.0	292.0	0.0
ATSI	Coupled	Annual, Extended Summer, and Limited	1,125.0	1,132.5	1,136.5	320.0	542.2	144.7

Table 18 Weighted-average sell offer prices for DR by LDA and offer/product type: 2015/2016 RPM Base Residual Auction

			Weighted-Average ($ per MW-day UCAP)		
LDA	Offer Type	Product Type(s)	Annual	Extended Summer	Limited
RTO	Non-coupled	Annual	$96.94		
RTO	Non-coupled	Extended Summer		$144.40	
RTO	Non-coupled	Limited			$64.15
RTO	Coupled	Annual and Extended Summer			
RTO	Coupled	Annual and Limited	$109.12		$20.00
RTO	Coupled	Extended Summer and Limited		$119.00	$107.72
RTO	Coupled	Annual, Extended Summer, and Limited	$101.29	$79.09	$59.33
MAAC	Non-coupled	Annual	$100.81		
MAAC	Non-coupled	Extended Summer		$122.19	
MAAC	Non-coupled	Limited			$71.53
MAAC	Coupled	Annual and Extended Summer			
MAAC	Coupled	Annual and Limited	$110.70		$20.00
MAAC	Coupled	Extended Summer and Limited		$115.03	$104.91
MAAC	Coupled	Annual, Extended Summer, and Limited	$108.05	$83.20	$60.00
ATSI	Non-coupled	Annual	$178.08		
ATSI	Non-coupled	Extended Summer		$266.91	
ATSI	Non-coupled	Limited			$54.27
ATSI	Coupled	Annual and Extended Summer			
ATSI	Coupled	Annual and Limited			
ATSI	Coupled	Extended Summer and Limited		$124.32	$118.32
ATSI	Coupled	Annual, Extended Summer, and Limited	$166.75	$140.40	$117.97

Table 19 Impact of DR product types: 2015/2016 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	$118.54	9,247.2		
	Extended Summer	$136.00	5,202.3		
	Annual	$136.00	150,111.7	$220.00	162,323.0
MAAC	Limited	$150.00	3,936.1		
	Extended Summer	$167.46	2,677.9		
	Annual	$167.46	59,176.4	$220.00	65,323.0
ATSI	Limited	$304.62	604.8		
	Extended Summer	$322.08	836.3		
	Annual	$357.00	9,226.5	$358.22	10,562.0

Table 20 Impact of Short Term Resource Procurement Target and DR product types: 2015/2016 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	$118.54	9,247.2		
	Extended Summer	$136.00	5,202.3		
	Annual	$136.00	150,111.7	$313.43	164,335.8
MAAC	Limited	$150.00	3,936.1		
	Extended Summer	$167.46	2,677.9		
	Annual	$167.46	59,176.4	$313.43	66,383.9
ATSI	Limited	$304.62	604.8		
	Extended Summer	$322.08	836.3		
	Annual	$357.00	9,226.5	$410.64	10,758.5

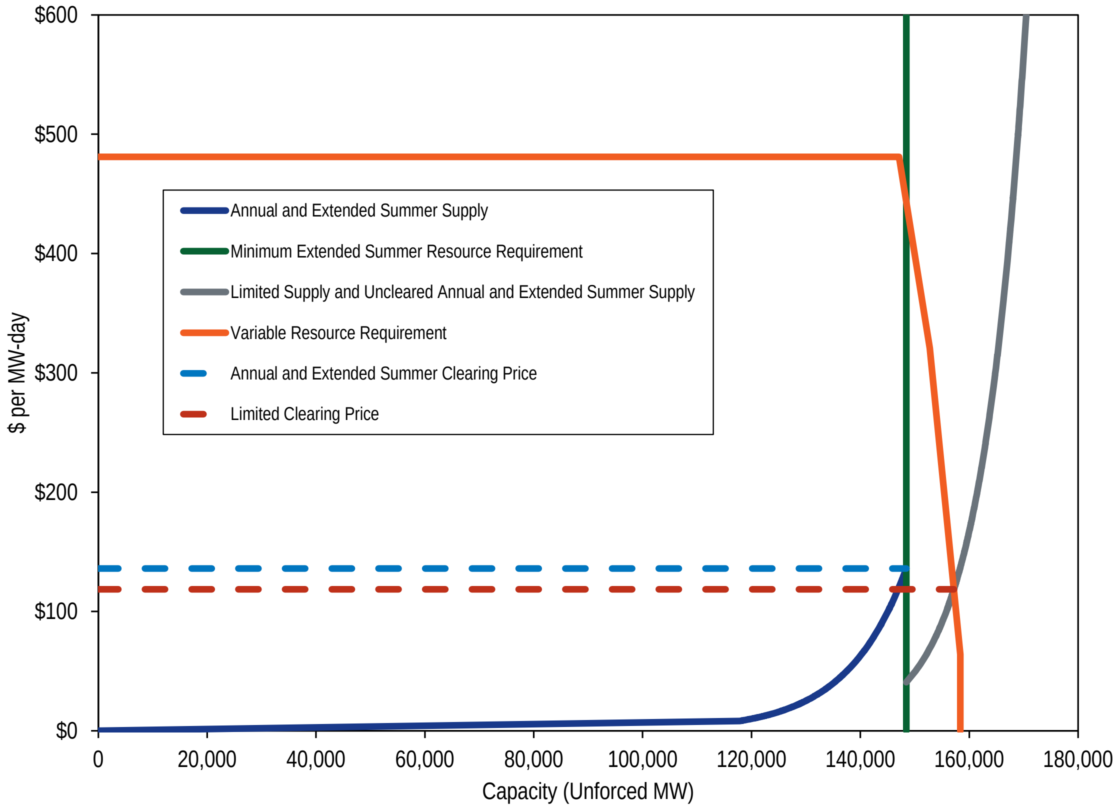
Table 21 Impact of DR: 2015/2016 RPM Base Residual Auction

		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	$118.54	9,247.2		
	Extended Summer	$136.00	5,202.3		
	Annual	$136.00	150,111.7	$401.42	156,381.4
MAAC	Limited	$150.00	3,936.1		
	Extended Summer	$167.46	2,677.9		
	Annual	$167.46	59,176.4	$401.42	63,550.3
ATSI	Limited	$304.62	604.8		
	Extended Summer	$322.08	836.3		
	Annual	$357.00	9,226.5	$537.33	9,690.5

Table 22 Impact of environmental regulations: 2015/2016 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	$118.54	9,247.2	$122.22	14,912.1
	Extended Summer	$136.00	5,202.3	$122.22	437.5
	Annual	$136.00	150,111.7	$122.22	148,943.0
MAAC	Limited	$150.00	3,936.1	$122.22	6,346.9
	Extended Summer	$167.46	2,677.9	$122.22	354.8
	Annual	$167.46	59,176.4	$122.22	59,605.8
ATSI	Limited	$304.62	604.8	$357.00	1,863.3
	Extended Summer	$322.08	836.3	$357.00	51.6
	Annual	$357.00	9,226.5	$357.00	8,651.6

Figure 1 RTO market supply/demand curves: 2015/2016 RPM Base Residual Auction[95, 96]



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95 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.

96 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 and Minimum Extended Summer Resource Requirement exclude incremental demand which cleared in MAAC and ATSI.

MAAC Market Results

Table 23 shows total MAAC offer data for the 2015/2016 RPM Base Residual Auction. All MW values stated in the MAAC section include all LDAs nested within MAAC. Total internal MAAC unforced capacity of 79,793.1 MW includes all Generation Capacity Resources, Demand Resources, and Energy Efficiency Resources that qualified as PJM Capacity Resources, excluding external units, and also includes owners' modifications to ICAP ratings. As shown in Table 9, MAAC unforced internal capacity increased 3,544.1 MW from 76,249.0 MW in the 2014/2015 BRA as a result of net generation capacity modifications (3,125.9 MW), net DR modifications (-149.6 MW), and net EE modifications (29.4 MW), the EFORd effect due to lower sell offer EFORds (508.9 MW), and the DR and EE effect due to a higher Load Management UCAP conversion factor (29.5 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 79,793.1 MW.[97] RPM capacity was reduced by 674.0 MW of exports, 53.5 MW of Planned Generation Capacity Resources which were not subject to the RPM must offer requirement, and 1,494.5 MW excused from the RPM must offer requirement. The excused Existing Generation Capacity Resources were the result of plans for retirement (1,447.1 MW), significant physical operational restrictions (43.6 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 (3.8 MW). Subtracting 3,303.8 MW of DR and EE not offered, resulted in available unforced capacity in MAAC of 74,267.3 MW.[98] After accounting for the above exceptions, 6.8 MW in MAAC were not offered in the RPM Auction.

The MAAC LDA import limit was a binding constraint in the 2015/2016 BRA. Of the 65,790.4 MW cleared in MAAC, 63,565.9 MW were cleared in the RTO before MAAC became constrained. Once the constraint was binding, based on the 6,456.0 MW CETL value, only the incremental supply located in MAAC was available to meet the incremental demand in the LDA. Of the incremental supply, 2,224.5 MW cleared, which resulted in a clearing price for Limited Resources of $150.00 per MW-day, as shown in Figure 2. The clearing price was determined by the intersection of the incremental supply and VRR Curve.

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[97] PJM. "Manual 18: PJM Capacity Market," Revision 16 (September 27, 2012), p. 44.

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

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 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.

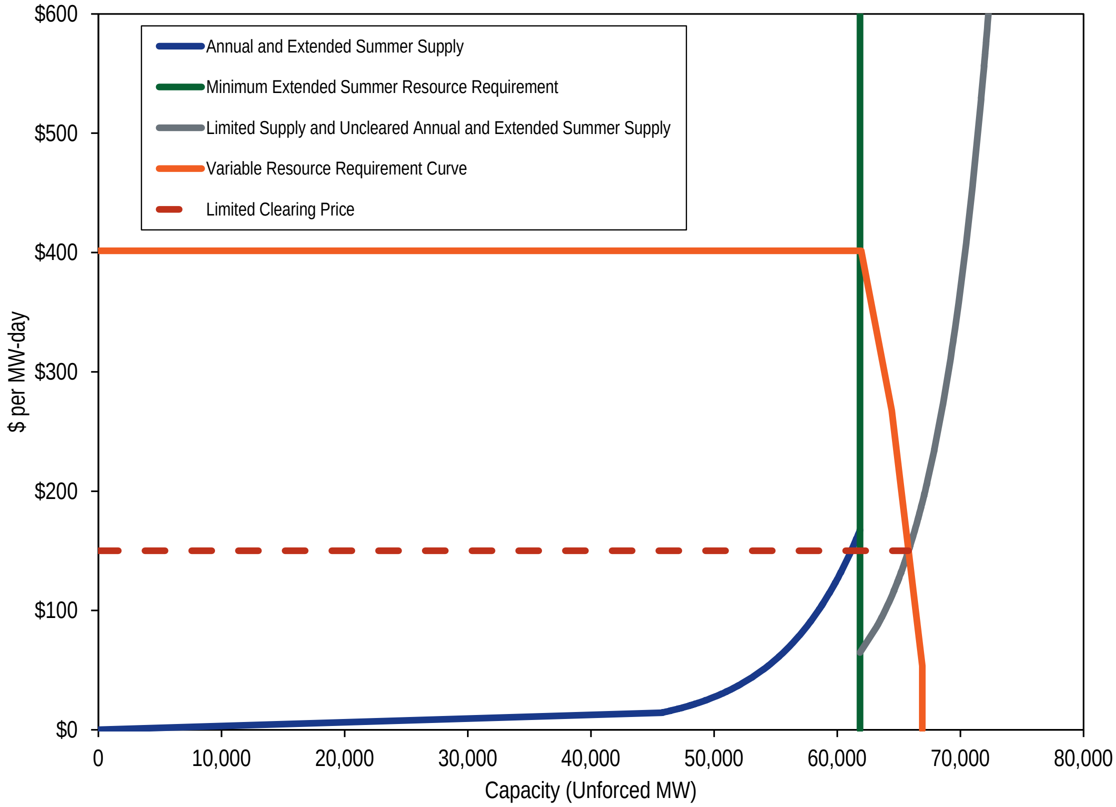
The Minimum Extended Summer Resource Requirement was a binding constraint for RTO in the 2015/2016 BRA. This means that the auction clearing mechanism resulted in a higher price for Extended Summer and Annual Resources. Annual and Extended Summer Resources in MAAC received a clearing price of $167.46 per MW-day. Higher priced Extended Summer Resources were required in order to meet the minimum reliability requirement for such resources. Annual Resources contribute to meeting the Minimum Extended Summer Resource Requirement, so both Annual Resources and Extended Summer DR receive the higher price.

Table and Figures for MAAC

Table 23 MAAC offer statistics: 2015/2016 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	70,496.4	67,088.8		
DR capacity	12,022.1	12,467.1		
EE capacity	229.1	237.2		
Total internal MAAC capacity	82,747.6	79,793.1		
FRR	0.0	0.0		
Imports	0.0	0.0		
RPM capacity	82,747.6	79,793.1		
Exports	(674.0)	(674.0)		
FRR optional	0.0	0.0		
Excused Existing Generation Capacity Resources	(1,750.6)	(1,494.5)		
Unoffered Planned Generation Capacity Resources	(53.5)	(53.5)		
Unoffered DR and EE	(3,186.2)	(3,303.8)		
Available	77,083.3	74,267.3	100.0%	100.0%
Generation offered	68,010.3	64,860.0	88.2%	87.3%
DR offered	8,835.9	9,163.3	11.5%	12.3%
EE offered	229.1	237.2	0.3%	0.3%
Total offered	77,075.3	74,260.5	100.0%	99.9%
Unoffered	8.0	6.8	0.0%	0.0%
Cleared in RTO		63,565.9		85.6%
Cleared in MAAC		2,224.5		3.0%
Total cleared		65,790.4		88.6%
Make-whole		0.0		0.0%
Reliability requirement		71,623.0		
Total cleared plus make-whole		65,790.4		
CETL		6,456.0		
Total Resources		72,246.4		
Short-Term Resource Procurement Target		1,658.9		
Net excess/(deficit)		2,282.3		
Resource clearing price for Limited Resources ($ per MW-day)		$150.00		
Resource clearing price for Extended Summer Resources ($ per MW-day)		$167.46		
Resource clearing price for Annual Resources ($ per MW-day)		$167.46		
Preliminary zonal capacity price ($ per MW-day)		$166.08	A	
Base zonal CTR credit rate ($ per MW-day)		$0.30	B	
Preliminary net load price ($ per MW-day)		$165.78	A-B	

Figure 2 MAAC market supply/demand curves: 2015/2016 RPM Base Residual Auction[99,100]



ATSI Market Results

Table 24 shows total ATSI offer data for the 2015/2016 RPM Base Residual Auction. Total internal ATSI unforced capacity of 14,407.5 MW includes all Generation Capacity Resources, Demand Resources, and Energy Efficiency Resources that qualified as PJM Capacity Resources, excluding external units, and also includes owners' modifications to ICAP ratings. As shown in Table 9, ATSI unforced internal capacity increased 3,862.3

99 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.

100 The Minimum Extended Summer Resource Requirement was not a binding constraint in MAAC in the 2015/2016 RPM Base Residual Auction, and the MAAC clearing price for Extended Summer Resources was based on the RTO Extended Summer Resource Price Adder.

MW from 10,545.2 MW in the 2014/2015 BRA as a result of net generation capacity modifications (918.2 MW), net DR modifications (2,729.0 MW), and net EE modifications (78.2 MW), the EFORd effect due to lower sell offer EFORds (133.6 MW), and the DR and EE effect due to a higher Load Management UCAP conversion factor (3.3 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 14,407.5 MW. There were no exports from ATSI. RPM capacity was reduced by 1,813.6 MW excused from the RPM must offer requirement as a result of plans for retirement. Subtracting 816.8 MW of DR and EE not offered, resulted in available unforced capacity in ATSI of 11,777.1 MW.[101] 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 2015/2016 BRA. Of the 10,667.6 MW cleared in ATSI, 5,789.4 MW were cleared in the RTO before ATSI became constrained. Once the constraint was binding, based on the 10,669.1 MW CETL value, only the incremental supply located in ATSI was available to meet the incremental demand in the LDA. Of the incremental supply, 4,878.2 MW cleared, which resulted in a clearing price for Limited Resources of $304.62 per MW-day, as shown in Figure 3. The clearing price was determined by the intersection of the incremental supply and VRR curve.

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 Annual Resource Requirement was a binding constraint for ATSI in the 2015/2016 BRA and as a result, Annual Resources in ATSI received a clearing price of $357.00 per MW-day.

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

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

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.

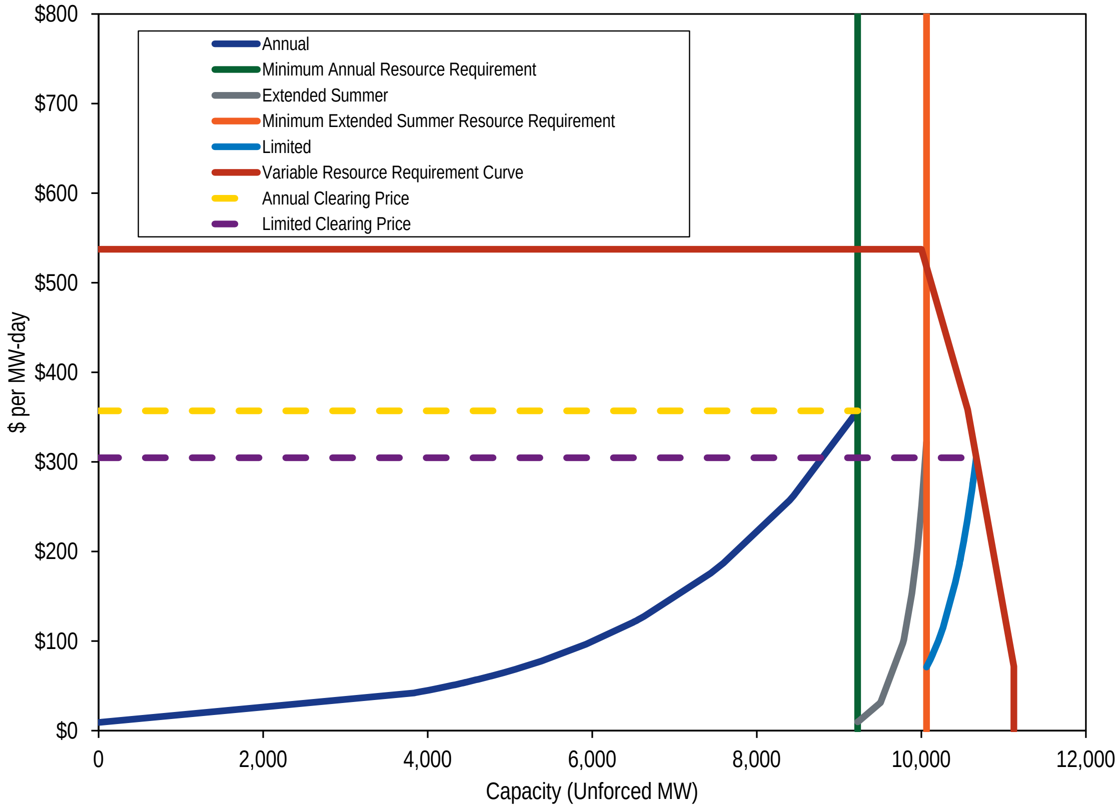
The Minimum Extended Summer Resource Requirement was a binding constraint for RTO in the 2015/2016 BRA and as a result Extended Summer Resources in ATSI received a clearing price of $322.08 per MW-day.

Table and Figure for ATSI

Table 24 ATSI offer statistics: 2015/2016 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	12,156.6	11,504.1		
DR capacity	2,723.9	2,825.2		
EE capacity	75.5	78.2		
Total internal ATSI capacity	14,956.0	14,407.5		
FRR	0.0	0.0		
Imports	0.0	0.0		
RPM capacity	14,956.0	14,407.5		
Exports	0.0	0.0		
FRR optional	0.0	0.0		
Excused Existing Generation Capacity Resources	(2,006.5)	(1,813.6)		
Unoffered Planned Generation Capacity Resources	0.0	0.0		
Unoffered DR and EE	(787.2)	(816.8)		
Available	12,162.3	11,777.1	100.0%	100.0%
Generation offered	10,150.1	9,690.5	83.5%	82.3%
DR offered	1,965.7	2,038.5	16.2%	17.3%
EE offered	46.5	48.1	0.4%	0.4%
Total offered	12,162.3	11,777.1	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO		5,789.4		49.2%
Cleared in ATSI		4,878.2		41.4%
Total cleared		10,667.6		90.6%
Make-whole		1.5		0.0%
Reliability requirement		16,201.0		
Total cleared plus make-whole		10,669.1		
CETL		5,417.8		
Total Resources		16,086.9		
Short-Term Resource Procurement Target		360.5		
Net excess/(deficit)		246.4		
Resource clearing price for Limited Resources ($ per MW-day)		$304.62		
Resource clearing price for Extended Summer Resources ($ per MW-day)		$322.08		
Resource clearing price for Annual Resources ($ per MW-day)		$357.00		
Preliminary zonal capacity price ($ per MW-day)		$342.30	A	
Base zonal CTR credit rate ($ per MW-day)		$48.27	B	
Preliminary net load price ($ per MW-day)		$294.03	A-B	

Figure 3 ATSI market supply/demand curves: 2015/2016 RPM Base Residual Auction[102,103]



102 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.

103 The Minimum Extended Summer Resource Requirement was not a binding constraint in ATSI in the 2015/2016 RPM Base Residual Auction, and the ATSI clearing price for Extended Summer Resources was based on the RTO Extended Summer Resource Price Adder.

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.[1] 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 Variable Resource Requirement, 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. Therefore, in the RPM algorithm, the mixed integer optimization problem is solved iteratively, where after every iteration, the parent LDAs' VRR curves are reconfigured to reflect their respective child LDAs' cleared capacity. The process is repeated until an equilibrium point is reached. The method preserves the mixed integer feature of the optimization problem while allowing for incorporation of the 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

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1 OATT Attachment DD § 5.12(a).

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 is made whole for the shortfall. 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 Slight Differences between PJM and MMU Solutions

It is possible for the MMU's solution to the BRA optimization problem to differ slightly from PJM's solution. 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 computing characteristics.
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 2015/2016 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 0.04 percent of the corresponding total MW cleared under PJM's method. The clearing prices using the MMU's approach are within 2.00 percent of the corresponding clearing prices under PJM's method.

Illustration of BRA Clearing Algorithm

The objective in the auction's 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 4 and Figure 5 show an example child VRR and parent VRR curves respectively. To illustrate the price formation in the BRA, two example scenarios are presented. In the first scenario, a larger CETL is assumed between the parent LDA and the child LDA. In the second scenario, a relatively tighter CETL is assumed between the parent LDA and the child LDA. All offers and parameters, with the exception of the CETL, are identical between the two scenarios. In both scenarios, only one type of resource and only one requirement are considered.[2]

Figure 6 and Figure 7 illustrate the solution for the first scenario. Only a part, 189.1 MW, out of the available 300 MW CETL is utilized. Therefore the CETL constraint is non-binding and high-priced 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, indicating the equal tradeoff between clearing a resource from the child LDA against clearing a resource from the parent LDA.

Figure 8 and Figure 9 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. High-priced 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. Accordingly, the marginal clearing prices of the parent LDA and the child LDA are $106.70 and $120.00 per MW-day respectively.

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

Figure 4 Variable Resource Requirement Curve: Child LDA

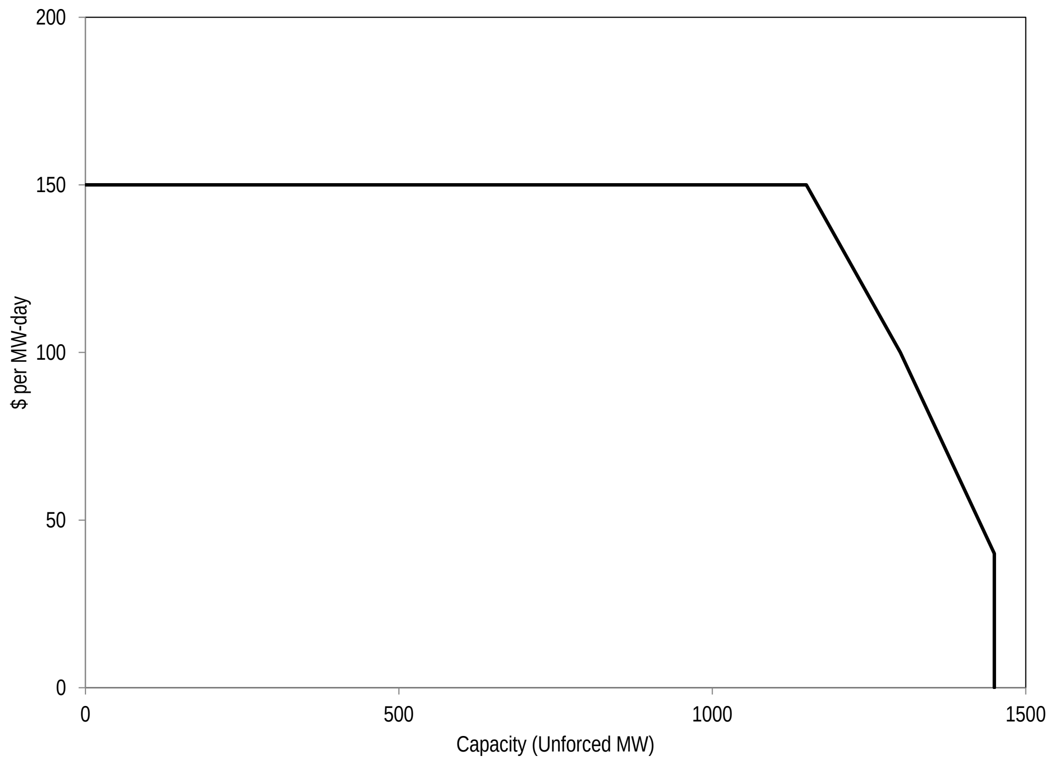

Figure 5 Nested Variable Resource Requirement Curve: Parent LDA

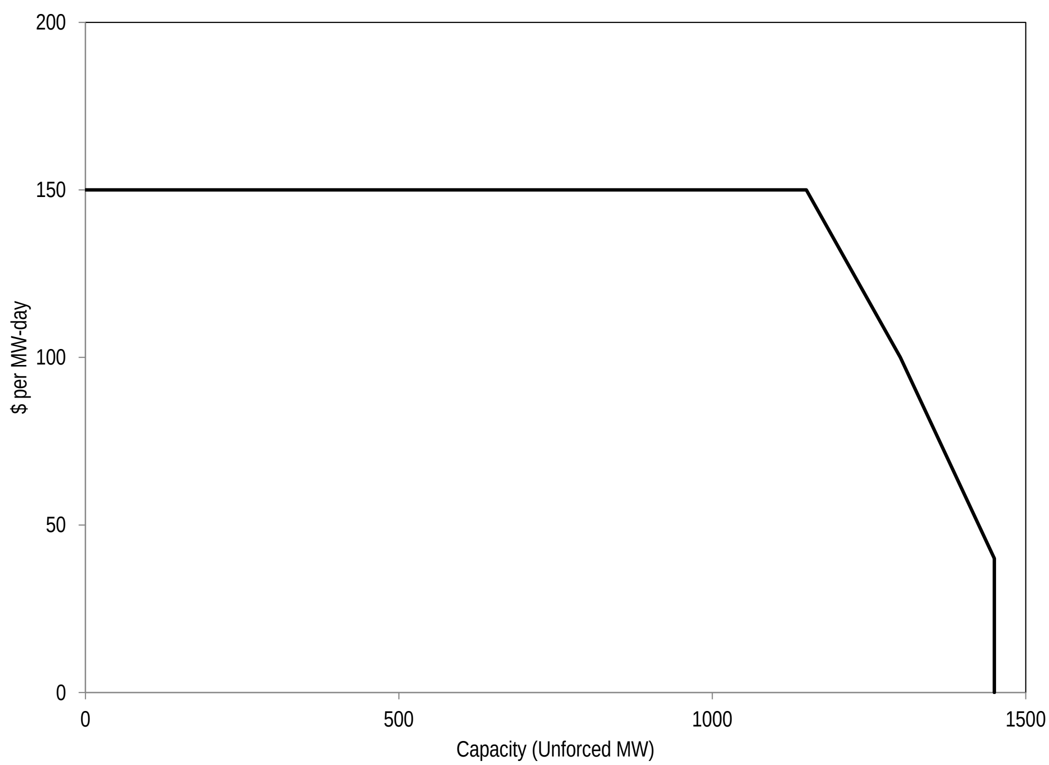

Figure 6 Optimal solution for scenario 1: Child LDA

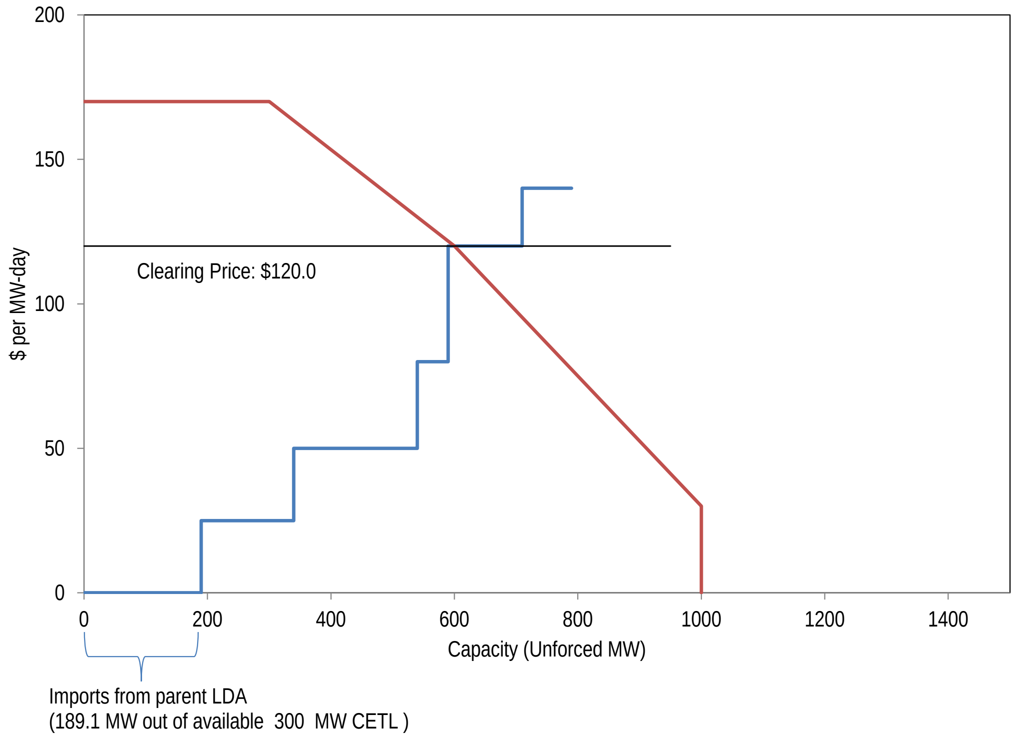

Figure 7 Optimal solution for scenario 1: Parent LDA

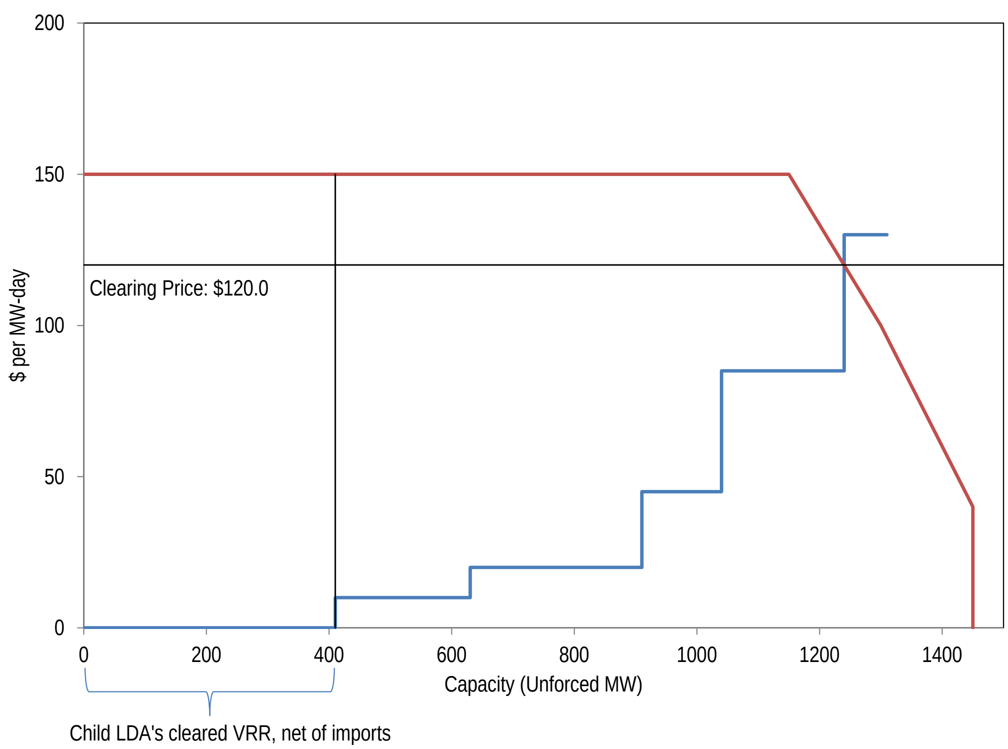

Figure 8 Optimal solution for scenario 2: Child LDA

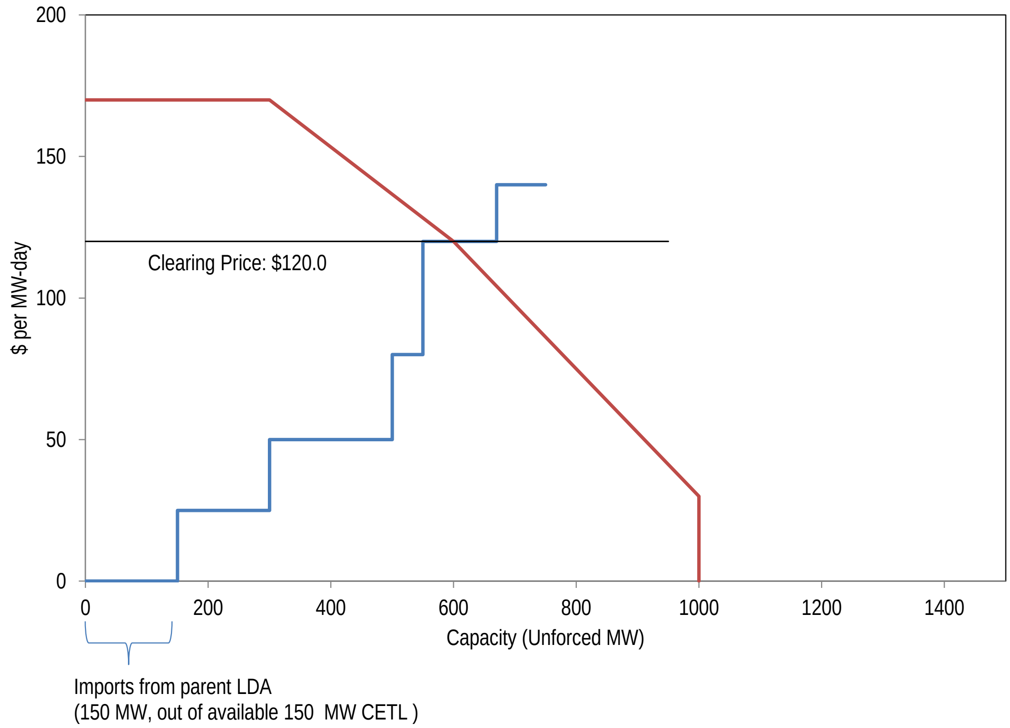

Figure 9 Optimal solution for scenario 2: Parent LDA