Monitoring Analytics

Analysis of the 2014/2015 RPM Base Residual Auction

The Independent Market Monitor for PJM

April 9, 2012

Introduction

This report, prepared by the Independent Market Monitor for PJM (IMM or MMU), reviews the functioning of the eighth Reliability Pricing Model (RPM) Base Residual Auction (BRA) (for the 2014/2015 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 shape of the Variable Resource Requirement (VRR) curve; constrained Locational Deliverability Areas (LDAs); the Short-Term Resource Procurement Target; Demand Resources (DR); changes in CETL; and 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 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; 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 and PSEG North RPM markets failed the three pivotal supplier (TPS) test. All generation included in the incremental supply in MAAC passed the test. The result was that, for all generation offers except MAAC incremental offers, 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 increased market clearing price.[2, 3] The offer caps are designed to reflect the marginal cost of capacity. The absence of mitigation for incremental MAAC generation offers had no impact on the clearing prices in the auction. Based on these facts, the MMU concludes that the results of the 2014/2015 RPM Base Residual Auction were competitive.

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

In particular, the MMU recommends that the use of the 2.5 percent demand adjustment (Short-Term Resource Procurement Target) be terminated immediately. The MMU 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

---

1 Attachment B 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 The definition of Planned Generation Capacity Resource and the rules regarding mitigation were redefined effective January 31, 2011. See 134 FERC ¶ 61,065 (2011).

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 reflect the actual flexibility of units in responding to price signals.[4, 5] The result is higher net revenues, which affects the parameters of the RPM demand curve and market outcomes. The MMU recommends that the recent rule change requiring that relatively small increases in capacity be treated as new resources and exempted from offer capping be removed. The MMU recommends that, as part of the MOPR 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]

The MMU also recommends that, prior to estimating the default 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.[7] 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.

Results

The shape of the demand curve, the VRR curve, had a significant impact on the outcome of the auction. As a result of the downward sloping VRR demand curve, more capacity cleared in the market than would have cleared with a vertical demand curve equal to the reliability requirement. As shown in Table 6, the 149,974.7 MW of cleared resources for the entire RTO, which represented a reserve margin of 20.6 percent, resulted in net excess of 5,472.3 MW over the reliability requirement of 148,323.1 MW which represents a reserve margin of 15.3 percent.

The changes in CETL values between the prior BRA and this BRA resulted in a decrease in auction revenues. Based on actual auction clearing prices and quantities and make-

---

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 *Comments of the Independent Market Monitor for PJM*, Docket Nos. EL11-20 and ER11-2875 (March 4, 2011)

7 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).

whole MW, total RPM market revenues for the 2014/2015 RPM Base Residual Auction were $7,258,389,284. If the market clearing used the CETL values from the 2013/2014 RPM Base Residual Auction, total RPM market revenues for the 2014/2015 RPM Base Residual Auction would have been $7,498,575,916, a difference of $240,186,632. The change in CETL values resulted in a reduction in auction revenues of three percent compared to the total based on the prior CETL values.

The reduction in demand for capacity by 2.5 percent had a significant impact on the auction results. The removal of 2.5 percent of demand significantly reduced the clearing prices and quantities for most RPM markets. There was no change in the clearing price for the PSEG North LDA, except that the clearing price for Limited DR was slightly lower as a result of the 2.5 percent demand reduction. 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 2014/2015 RPM Base Residual Auction were $7,258,389,284. If the VRR curves and Minimum Resource Requirements had not been reduced by the Short-Term Resource Procurement Target, total RPM market revenues for the 2014/2015 RPM Base Residual Auction would have been $8,494,547,168, an increase of $1,236,157,884, or 17 percent, compared to the actual results.

The inclusion of inferior demand side products in the auction had a significant impact on the auction results. Based on actual auction clearing prices and quantities, total RPM market revenues for the 2014/2015 RPM Base Residual Auction were $7,258,389,284. If only generation and annual DR were offered in the 2014/2015 RPM Base Residual Auction, total RPM market revenues for the 2014/2015 RPM Base Residual Auction would have been $9,631,126,037, an increase of $2,372,736,753, or 33 percent, compared to the actual results.

The inclusion of expected investments based on the implementation of the EPA's MACT rules had a significant impact on the auction results. Of the 7,437.1 MW of uncleared offers for subcritical/supercritical coal units, 5,898.1 MW were offers from resources including costs associated with EPA MACT 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 2014/2015 RPM Base Residual Auction were $7,258,389,284. If the APIR associated with the pending EPA MACT emissions standards which were not previously submitted were removed, total RPM market revenues for the 2014/2015 RPM Base Residual Auction would have been $5,897,269,210, a reduction of $1,361,120,074, or 19 percent, compared to the total based on actual results. The impact of including MACT requirements in APIR was to increase total market revenues by $1,361,120,074, or 23 percent.

Clearing Prices

Table 1 shows the clearing prices for Annual Resources in the 2014/2015 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 LDA.

Table 1 Clearing prices and net CONE: 2014/2015 RPM Base Residual Auction

LDA	Annual Clearing Price ($ per MW-day)	Net CONE ($ per MW-day)
RTO	$125.99	$342.23
MAAC	$136.50	$241.91
EMAAC	$136.50	$275.02
SWMAAC	$136.50	$241.91
PSEG	$136.50	$275.02
PSEG North	$225.00	$275.02
DPL South	$136.50	$275.02
Pepco	$136.50	$241.91

Market Changes

RPM Market Design Changes

The 2014/2015 RPM Base Residual Auction was the first BRA conducted under the revised RPM rules effective January 31, 2011, related to the RPM must-offer requirement and market power mitigation.[8] 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.[9] The changes to the MOPR included updating the calculation of the net Cost of New Entry (CONE) for CC and 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

---

8 134 FERC ¶ 61,065 (2011).

9 135 FERC ¶ 61,022 (2011).

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.[10]

The MOPR rule provided for a unit specific review by the MMU of offers by new units 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 an objective standard that should apply except in specific cases where the objective 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.

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.[11] 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 were defined as a Minimum Annual Resource Requirement and a Minimum Extended Summer Resource Requirement for the PJM region as a whole and LDAs for which a separate VRR curve is established.[12] Annual Resources include generation resources and Annual DR. The Minimum Resource Requirements are targets established by PJM to ensure that a sufficient amount of Annual Resources are procured in order to address certain reliability concerns associated with the Extended Summer and Limited DR products and that a sufficient amount of Annual Resources and Extended Summer Resources are procured in order to address certain reliability concerns associated with the Limited DR product. The identified reliability risk associated with relying on either the Extended Summer or Limited DR products is the risk of relying on resources that are not required to respond at all times of the year 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. The Minimum Extended Summer Resource Requirement is the minimum amount of capacity that PJM will seek to procure

---

10 FERC subsequently issued an order on November 17, 2011, which included clarification on the duration of mitigation and which resources are subject to the MOPR. See 137 FERC ¶ 61,145 (2011).

11 134 FERC ¶ 61,066 (2011).

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

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 because additional purchases of these products is not consistent with reliability.

As part of the definition of the new DR products, coupled DR sell offers were defined. Coupled DR sell offers are linked sell offers for a Demand Resource that can qualify for more than one of the three DR product types. For example, a DR offer based on a single facility could be offered as Annual, Extended Summer and Limited simultaneously in a coupled offer. Only Demand Resources of different product types may be coupled, and the Capacity Market Seller must specify a sell offer price of at least $0.01 per MW-day more for the less limited DR product type within a coupled segment group. PJM's auction clearing mechanism will select Annual Resources out of merit order if necessary to procure the defined minimum resource requirements for the annual product. Generation resources are Annual Resources as are DR Annual Resources. PJM's auction clearing mechanism will select Extended Summer DR out of merit order if necessary to procure the defined minimum resource requirements for the sum of annual and extended summer products. 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. The more valuable products will receive a higher price if the constraints related to Extended Summer or Limited DR products are binding.

Effective in the 2014/2015 delivery year, the RPM market design also included the implementation of credit limited offers, which allows 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.[13] 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. This could permit participants to offer capacity when they could not otherwise offer capacity based on an uncertain credit limit that could vary substantially with clearing prices. 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 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

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

after posting the BRA results is the greater of $20 per MW-day or 20 percent of the LDA resource clearing price times the number of days in the Delivery Year.

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. If MPCE violations exist, such offers are removed and the RPM auction clearing mechanism is rerun until no MPCE violations exist. The problem is made more complex because the Post-Auction Credit Rate may be a function of the resource clearing price.

Other Changes Affecting Supply and Demand

The U.S. Environmental Protection Agency (EPA) issued, on March 16, 2011, a notice of proposed rulemaking (NOPR) in a proceeding to promulgate final 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 12(d) of the Clean Air Act. The MMU stated that the March 16th NOPR 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 as proposed in the March 16th NOPR.[14, 15]

The Duke Energy Ohio Kentucky (DEOK) Zone, which is to integrate into PJM on January 1, 2012, was included in RPM for the first time in the 2014/2015 RPM Base Residual Auction. Although the majority of the DEOK load is served under the FRR alternative, a small amount of load was included in the preliminary peak load forecast from which the reliability and VRR curve were derived.[16] Supply in the 2014/2015 RPM Base Residual Auction included resources in the DEOK Zone which were not committed to an FRR capacity plan.

---

14 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)

15 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).

16 See PJM "2014/2015 RPM Base Residual Auction Planning Period Parameters," <http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/20110102-rpm-bra-planning-parameters-2014-2015.ashx> (February 2, 2011).

The default Avoidable Cost Rate (ACR) values were adjusted from the levels used in the 2013/2014 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 2014/2015 BRA.[17]

Preliminary Market Structure Screen

Under the terms of the PJM Tariff, the MMU is required to apply the preliminary market structure screen (PMSS) prior to RPM Base Residual Auctions.[18] The purpose of the PMSS is 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 is 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.[19] The PMSS is applied separately for each LDA for which a separate VRR curve has been established by PJM for the delivery year.

An LDA or the Regional Transmission Organization (RTO) region fails the PMSS if any one of the following three screens is failed: (1) the market share of any capacity resource owner exceeds 20 percent; (2) the Herfindahl-Hirschman Index (HHI) for all capacity resource owners is 1800 or higher; or (3) there are not more than three jointly pivotal suppliers.[20] Capacity resource owners who own or control generation in the area that fails the PMSS and who intend to submit a non-zero sell offer price are required to provide Avoidable Cost Rate (ACR) data or a calculation of opportunity cost along with supporting documentation to the MMU.[21]

---

17 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).

18 OATT Attachment M (PJM Market Monitoring Plan)-Appendix § II.D.1.

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

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

21 OATT Attachment DD § 6.7 (b).

Consistent with the requirements of the Tariff, the MMU applied the PMSS 90 days prior to the 2014/2015 RPM Base Residual Auction. 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 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.[22]

Table 2 Preliminary Market Structure Screen results: 2014/2015

RPM Markets	Highest Market Share	HHI	Pivotal Suppliers	Pass/Fail
RTO	15.0%	800	1	Fail
MAAC	17.6%	1038	1	Fail
EMAAC	33.1%	1966	1	Fail
SWMAAC	49.4%	4733	1	Fail
PSEG	89.4%	8027	1	Fail
PSEG North	88.2%	7825	1	Fail
DPL South	56.5%	3796	1	Fail
Pepco	94.5%	8955	1	Fail

MMU Methodology

The MMU reviewed the following inputs to and results of the 2014/2015 RPM Base Residual Auction:[23]

- **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 2008 through 2010;

- **Minimum Offer Price Rule (MOPR).** Reviewed requests for exceptions to the MOPR to determine if consistent with costs;

22 OATT Attachment DD § 6.7 (c).

23 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 2014/2015 RPM Base Residual Auction.

- **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.** Approved 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, 2010;

- **Clearing Prices.** Verified that the auction clearing prices were accurate, based on submitted offers,[24] the Variable Resource Requirement (VRR) curves, and the Minimum Resource Requirements;

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

Market Structure Tests

As shown in Table 3, all participants in the RTO and PSEG North RPM markets failed the TPS test.[25] All participants included in the incremental supply of MAAC passed the 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 increased the market clearing price. Market power mitigation was applied to 29 Generation Capacity Resources, including 3,822.8 MW in the 2014/2015 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

---

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

25 See the *2010 State of the Market Report for PJM* (March 10, 2011), Volume II, Section 2, "Energy Market, Part 1," and Volume II, Appendix L, "Three Pivotal Supplier Test" for a more detailed discussion of market structure tests.

RTO cost-based clearing price.[26] 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.

In the 2014/2015 RPM Base Residual Auction, incremental demand in MAAC was 411.4 MW. The incremental supply in MAAC, considered in the application of the three pivotal supplier test, was 2,415.6 MW, including all offered MW from Generation Capacity Resources with sell offer prices greater than the RTO clearing price for Annual Resources of $125.99 per MW-day and less than or equal to 1.5 times the MAAC clearing price for Annual Resources of $136.50 per MW-day. The incremental supply in MAAC was offered by seven parent companies. Of the incremental supply in MAAC that passed the test, the submitted sell offers were at or below the defined offer caps or would not have increased the market clearing price if mitigation were not applied. Therefore, passing of the TPS test in MAAC had no effect on clearing prices.

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 owners have a reduced ability to unilaterally influence market price.[27] MAAC/SWMAAC/EMAAC/PSEG/DPL South/Pepco are presented together because SWMAAC, EMAAC, PSEG, DPL South, and Pepco were modeled but were not constrained LDAs in this auction.

---

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

27 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 *2010 State of the Market Report for PJM* (March 10, 2011), Appendix L, "Three Pivotal Supplier Test" for additional discussion.

Table 3 RSI Results: 2014/2015 RPM Base Residual Auction[28]

	$RSI_{1\ 1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
RTO	0.76	0.58	93	93
MAAC/SWMAAC/EMAAC/PSEG/DPL South/Pepco	1.40	1.03	7	0
PSEG North	0.00	0.00	1	1

Offer Caps

The defined Generation Capacity Resource owners were required to submit ACR or opportunity cost data to the MMU by two months prior to the 2014/2015 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.[29] 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.[30] 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 maintain a unit as a Generation Capacity Resource, termed 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.[31]

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

---

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

29 OATT Attachment DD § 6.5.

30 OATT Attachment DD § 6.8 (b).

31 OATT Attachment DD § 6.8 (a).

the RPM market. If the opportunity cost is greater than the clearing price, the Generation Capacity Resource does not clear in the RPM market, and if the resource is internal to PJM, it is available for export.

ACR Offers

As shown in Table 4, offers were submitted for 1,152 generation resources in the 2014/2015 RPM Base Residual Auction compared to 1,170 generation resources offered in the 2013/2014 RPM Base Residual Auction, or a net decrease of 18 generation resources. This was a result of 61 fewer generation resources offered offset by 43 additional generation resources offered.

The 43 additional generation resources offered consisted of 39 new resources (1,038.5 MW), two additional resources imported (577.6 MW), one reactivated resource (8.1 MW), and one Duke Energy Ohio and Kentucky (DEOK) integration resource (22.5 MW).[32] The new Generation Capacity Resources consisted of 17 solar resources (30.2 MW), seven wind resources (146.6 MW), seven diesel resources (31.5 MW), five hydroelectric resources (132.7), two CT units (76.7 MW), and one combined cycle unit (620.8 MW). The reactivated Generation Capacity Resources consisted of one diesel resource (8.1 MW).

The 61 fewer generation resources offered consisted of 12 deactivated resources (936.8 MW), 12 additional resources excused from offering (1,129.9 MW), 32 additional resources committed fully to FRR (2,175.0 MW), four Planned Generation Capacity Resources not offered (240.0 MW), and one external generation resource not offered (6.6 MW). In addition, there were the following retirements of resources that were either exported or excused in the 2013/2014 BRA: two combustion turbine (CT) units (2.5 MW). The publicly posted deactivation requests include Kingsland (1.4 MW) in PSEG North; Baleville (1.1 MW) in PSEG; Indian River 3 (154.5 MW) in DPL South; Vineland 9 (17.0 MW) in EMAAC; and State Line Coal 3 (178.6 MW) and State Line Coal 4 (299.6) in RTO.[33] Resources that are no longer capacity resources but were not required to have public notifications of future deactivations consisted of four CT units (46.0 MW), two steam units (233.7 MW), and two diesel resources (7.4 MW).

---

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

33 This list includes those deactivations publicly posted by PJM and may not consider deactivation notices in company press releases. See PJM Generation Retirements webpage, <http://www.pjm.com/planning/generation-retirements.aspx>.

The MMU calculated offer caps for 709 generation resources, of which 561 were based on the technology specific default (proxy) ACR values.[34] No generation resources elected to use the retirement ACR in the 2014/2015 BRA. The 2014/2015 default ACR values were escalated from the 2013/2014 ACR values by PJM using the previously estimated base year values for 2013/2014 rather than incorporating the most recent Handy-Whitman Index value for 2010 in calculating the base year value. Unit-specific offer caps were calculated for 141 generation resources (12.2 percent) including 138 generation resources (12.0 percent) with an Avoidable Project Investment Recovery Rate (APIR) component and 3 generation resources (0.3 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 1,152 generation resources, 22 Planned Generation Capacity Resources had uncapped offers, 11 generation resources had uncapped planned uprates along with default ACR based offer caps calculated for the existing portion, six generation resources had uncapped planned uprates along with price taker status for the existing portion, while the remaining 415 generation resources were price takers, of which the offers for 413 generation resources were zero and the offers for two generation resources were set to zero because no data were submitted.[35]

As shown in Table 5, the weighted average gross ACR for units with APIR ($437.99 per MW-day) and the weighted-average offer caps, net of net revenues, for units with APIR ($274.45 per MW-day) increased from the 2013/2014 BRA values of $390.05 per MW-day and $134.44 per MW-day, due primarily to higher weighted average gross ACRs for CTs and resources in the other category (diesel, pumped storage, hydro, waste coal) and lower weighted-average net revenues. Weighted average APIR decreased for all categories except CTs.

The APIR component added an average of $268.95 per MW-day to the ACR value of the APIR units compared to $268.59 per MW-day in the 2013/2014 BRA.[36, 37] The highest

34 Six generation resources had both ACR based and opportunity cost based offer caps calculated, and 11 generation resources had uncapped planned uprates along with ACR based offer caps calculated for the existing portion.

35 Planned generation is subject to different market power mitigation rules than existing generation. For RPM rules regarding mitigation, see OATT Attachment DD § 6.5 (a) (ii). For the definition of planned generation, see "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region", Section 1.70.

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

APIR for a technology ($313.68 per MW-day) was for subcritical/supercritical coal units. The maximum APIR effect ($744.80 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, increased from $14.09 per MW-day to $25.32 per MW-day due primarily to lower weighted-average net revenues and higher weighted-average gross ACR for units without an APIR component.[38]

Table 4 ACR statistics: 2014/2015 RPM Base Residual Auction

Offer Cap/Mitigation Type	Number of Resources	Percent of Generation Resources Offered
Default ACR	544	47.2%
ACR data input (APIR)	138	12.0%
ACR data input (non-APIR)	3	0.3%
Opportunity cost	7	0.6%
Default ACR and opportunity cost	6	0.5%
Uncapped planned uprates and default ACR	11	1.0%
Uncapped planned uprates and opportunity cost	0	0.0%
Uncapped planned uprates and price taker	6	0.5%
Uncapped planned generation resources	22	1.9%
Existing generation resources as price takers	415	36.0%
Generation capacity resources offered	1,152	100.0%

37 The 138 resources which had an APIR component submitted $815.6 million for capital projects associated with 21,673.4 MW of UCAP.

38 The default ACR values include an average APIR of $1.42 per MW-day, which is the average APIR ($1.37 per MW-day) for the previously estimated default ACR values in the 2013/2014 BRA escalated using the most recent Handy-Whitman Index value.

Table 5 APIR statistics: 2014/2015 RPM Base Residual Auction[39, 40]

	Weighted-Average ($ per MW-day UCAP)					
	Combined Cycle	Combustion Turbine	Oil or Gas Steam	Subcritical/ Supercritical Coal	Other	Total
Non-APIR units						
ACR	$47.04	$34.61	$84.19	$222.70	$58.86	$110.52
Net revenues	$112.21	$29.80	$14.52	$306.01	$226.46	$152.35
Offer caps	$8.92	$16.34	$74.66	$28.52	$16.68	$25.32
APIR units						
ACR	NA	$65.34	$278.46	$511.79	$330.13	$437.99
Net revenues	NA	$18.24	$55.97	$222.06	$138.36	$182.98
Offer caps	NA	$51.46	$222.49	$313.68	$191.78	$274.45
APIR	NA	$38.99	$185.24	$313.37	$1.67	$268.95
Maximum APIR effect						$744.80

RTO Market Results

Table 6 shows total RTO offer data for the 2014/2015 RPM Base Residual Auction. All MW values stated in the RTO section include all nested LDAs.[41, 42] As shown in Table 8, total internal RTO unforced capacity (UCAP) increased 11,588.8 MW (4.6 percent) from 184,647.0 MW in the 2013/2014 RPM BRA to 196,235.8 MW.[43, 44]

---

39 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.

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

41 Nested LDAs occur when a constrained LDA is a subset of a larger constrained LDA or the RTO. For example, MAAC is nested in the RTO, while PSEG North is nested in MAAC.

42 Maps of the LDAs can be found in the *2010 State of the Market Report for PJM*, Appendix A, "PJM Geography."

43 The total internal RTO internal capacity for the 2013/2014 BRA was 195,602.2 MW ICAP and 184,647.0 MW UCAP. These values differ from the values of 195,633.4 MW ICAP and 184,678.2 MW UCAP reported in the "Analysis of the 2013/2014 RPM Base Residual Auction Revised and Updated" (September 20, 2010) due to a correction in the modeling of a resource.

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 11,588.8 MW increase in internal capacity was a result of net generation capacity modifications (cap mods) (54.7 MW), net DR modifications (6,940.0 MW), net EE modifications (49.4 MW), the EFORd effect due to higher sell offer EFORds (-271.7 MW), the DR and EE effect due to a lower Load Management UCAP conversion factor (-0.4 MW), and the integration of the DEOK Zone (4,816.8 MW).[45, 46, 47]

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 resources, demand resources, and energy efficiency resources that qualified as PJM Capacity Resources for the 2014/2015 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.[48] The ICAP of a unit may only be reduced through a cap mod if the capacity owner does not intend to restore the reduced capability by the end of the planning period following the planning period in question.[49]

---

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

45 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.

46 The UCAP value of a load management product is equal to the ICAP value multiplied by the Demand Resource Factor and the Forecast Pool Requirement (FPR). For the 2013/2014 BRA, this conversion factor was 0.957*1.0804 = 1.0339. For the 2014/2015 BRA, this factor was 0.956*1.0809 = 1.0333. The Demand Resource 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 Section B of Schedule 6 of the PJM Reliability Assurance Agreement.

47 PJM. "Manual 20: PJM Resource Adequacy Analysis," Revision 04 (June 1, 2011), p. 12-14.

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

49 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."

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 169,629.8 MW compared to 164,930.0 MW in the 2013/2014 RPM Base Residual Auction.[50] FRR volumes increased by 6,565.1 MW primarily due to the election of FRR by load serving entities in the DEOK Zone, and imports increased by 323.9 MW. Of the 4,055.5 MW of imports, 1,039.0 MW were committed to an FRR capacity plan and 3,016.5 MW were offered in the auction, of which all 3,016.5 MW cleared. Of the cleared imports, 922.7 MW, 31 percent, were from MISO. RPM capacity was reduced by exports of 1,228.1 MW. In addition, RPM capacity was reduced by 594.1 MW which were excused from the RPM must offer requirement as a result of significant physical operational restrictions (36.9 MW), environmental restrictions (507.7 MW), and the resource being considered existing in terms of mitigation only because it cleared an RPM Auction in a prior delivery year but is unable to achieve full commercial operation prior to the delivery year (49.5).[51] Exports decreased by 1,210.3 MW, and excused generation volumes increased 589.6 MW from the 2013/2014 RPM Base Residual Auction. Subtracting 2,088.0 MW of FRR optional volumes not offered, an increase of 1,142.8 MW in FRR MW not offered from the 2013/2014 RPM Base Residual Auction, and 5,232.2 MW of DR and EE not offered, resulted in 160,487.4 MW that were available to be offered in the auction, a decrease of 410.7 MW from the 2013/2014 RPM Base Residual Auction.[52, 53] After accounting for the above, 1.1 MW were not offered in the RPM Auction.

Offered MW decreased 411.8 MW from 160,898.1 MW to 160,486.3 MW, while the overall RTO Reliability Requirement adjusted for FRR obligations, from which the

---

50 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.

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

52 FRR entities are allowed to offer in the RPM Auction excess volumes above their FRR quantities, subject to a sales cap amount. The 2,087.9 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.

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

demand curve is developed, decreased 1,665.6 MW from 149,988.7 MW to 148,323.1 MW.[54] 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.[55] The 1,665.6 MW decrease in the RTO Reliability Requirement adjusted for FRR obligations from the 2013/2014 RPM Base Residual Auction was a result of a 6,203.1 MW increase in the FRR obligation offset by a 4,537.5 MW increase in the RTO Reliability Requirement not adjusted for FRR, shifting the RTO market demand curve to the left. The forecast peak load expressed in terms of installed capacity increased 4,123.6 MW from the 2013/2014 RPM Base Residual Auction to 164,757.6 MW, including a peak load contribution of 5,811.6 MW for the DEOK Zone. The 4,537.5 MW increase in the RTO Reliability Requirement was a result of a 4,455.1 MW increase in the forecast peak load in UCAP terms holding the FPR constant at the 2013/2014 level plus 82.4 MW attributable to the change in the FPR.

The Minimum Extended Summer Resource Requirement was a binding constraint for the RTO in the 2014/2015 BRA. This means that the auction clearing mechanism selected resources out of merit order to procure the minimum quantity, and the resources selected to meet the minimum requirements received a price adder to the system marginal price. As shown in Figure 1, the resource clearing price for Limited Resources for the RTO was $125.47 per MW-day, the resource clearing price for Extended Summer and Annual Resource for the RTO was $125.99 per MW-day.

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 6, the preliminary net load price is $125.94 per MW-day in the RTO.

As shown in Table 6, the 149,974.7 MW of cleared resources for the entire RTO, which represented a reserve margin of 20.6 percent, resulted in net excess of 5,472.3 MW over the reliability requirement of 148,323.1 MW (Installed Reserve Margin (IRM) of 15.3

---

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

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

percent).[56, 57] Net excess decreased 1,046.0 MW from the net excess of 6,518.3 MW in the 2013/2014 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 $125.99 per MW-day, and the downward sloping VRR demand curve resulted in a clearing price for Limited Resources of $125.47 per MW-day.

If the market clears on a nonflexible supply segment, a sell offer that specifies a minimum block MW value greater than zero, the Capacity Market Seller will be assigned make-whole MW equal to the difference between the sell offer minimum block MW and the sell offer cleared MW quantity if that solution to the market clearing minimizes the cost of satisfying the reliability requirements across the PJM region.[58] 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.[59] The market results in the 2014/2015 BRA did not include a make-whole quantity or 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.[60, 61] 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.[62]

Table 9 shows cleared MW by zone and fuel source. Of the 144,108.8 MW offered by generation resources, 135,034.2 MW cleared (93.7 percent). Of the 149,974.7 cleared MW in the entire RTO, 25,617.5 MW (17.1 percent) cleared in ComEd, followed by 23,656.1 MW in Dominion (15.8 percent) and 12,143.1 MW (8.1 percent) in PPL. Of the 135,034.2

---

[56] Prior to the elimination of ILR, net excess under RPM was calculated as cleared capacity less the reliability requirement plus ILR. After the ILR forecast was replaced by the Short-Term Resource Procurement Target, net excess under RPM is calculated as cleared capacity less the reliability requirement plus the Short-Term Resource Procurement Target.

[57] The IRM remained the same as the 2013/2014 Base Residual Auction.

[58] OATT Attachment DD § 5.14 (b).

[59] OATT Attachment DD § 5.12 (a).

[60] OATT Attachment DD § 5.14 (c) (2).

[61] OATT Attachment DD § 6.8 (a).

[62] OATT Attachment DD § 5.14 (c) (2) (ii).

cleared MW from generation resources in the entire RTO, 44,713.3 MW (33.1 percent) were gas resources, followed by 42,264.0 MW (31.3 percent) from coal resources and 30,626.9 MW (22.7 percent) from nuclear resources.

The 10,399.0 MW uncleared MW in the entire RTO were the result of offer prices which exceeded the clearing prices. Of the 10,399.0 uncleared MW in the entire RTO, 9.8 MW were EE offers, 1,427.2 MW were DR offers, and the remaining 8,962.0 MW were generation offers. Table 10 presents details on the generation offers that did not clear. Of the 8,962.0 MW of uncleared generation offers, 6,096.6 MW (68.0 percent) were for generation resources greater than 40 years old, and 2,865.4 MW (32.0 percent) were for generation resources less than or equal to 40 years old. Of the 7,437.1 MW of uncleared offers for subcritical/supercritical coal units, 5,898.1 MW were offers from resources including costs associated with EPA MACT compliance that were not previously included in APIR.

Table 11 shows the auction results in the prior two delivery years for the generation resources that did not clear some or all MW in the 2014/2015 BRA. Of the 59 generation resources that did not clear 8,962.0 MW in the 2014/2015 BRA, 19 generation resources did not clear 1,414.0 MW in the 2013/2014 delivery year. Of those 19 generation resources that did not clear MW in the 2014/2015 and 2013/2014 delivery years, 8 resources did not clear 514.0 MW in the 2012/2013 delivery year. Thus, 1,414.0 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.[63] 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

---

[63] PJM. "Manual 14B: PJM Region Transmission Planning Process, Attachment C: PJM Deliverability Testing Methods," Revision 19 (September 15, 2011), p. 48. Manual 14B indicates that all "electrically cohesive load areas" are tested.

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.[64] Attachment A includes a table listing all the transmission upgrades included in the CETL/CETO modeling.[65]

Under the Tariff, PJM determines, in advance of each BRA, whether defined Locational Deliverability Areas (LDAs) will be modeled in the auction. Effective with the 2012/2013 delivery year, an LDA will be modeled as a potentially constrained LDA for a delivery year if the Capacity Emergency Transfer Limit (CETL) is less than 1.15 times the Capacity Emergency Transfer Objective (CETO), such LDA had a locational price adder in one or more of the three immediately preceding BRAs, or such LDA is determined by PJM in a preliminary analysis to be likely to have a locational price adder based on historic offer price levels. The rules also provide that starting with the 2012/2013 delivery year, EMAAC, SWMAAC, and MAAC LDAs will be modeled as potentially constrained LDAs regardless of the results of the above three tests.[66] 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."[67] A reliability requirement, a Variable Resource Requirement (VRR) curve, a Minimum Annual Resource Requirement, and a Minimum Extended Summer Resource Requirement are established for each modeled LDA.

Table 12 shows the CETL and CETO values used in the 2014/2015 study compared to the 2013/2014 values. The increase in CETL for the MAAC, SWMAAC, and Pepco LDAs is mainly due to the addition of the Brambleton 500kV substation and Brambleton 500/230

---

64 PJM. "Manual 18: PJM Capacity Market," Revision 13 (November 17, 2011), p. 10.

65 Attachment A was compiled from Key Expected Transmission Upgrades as posted on the PJM RPM Auction User Information webpage, <http://www.pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx>.

66 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.

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

kV transformer with an expected in-service date by June 1, 2014.[68] In addition, the increase in the SWMAAC LDA CETL was attributable to the addition of a second Conastone-Graceton 230 kV circuit with an expected in-service date by June 1, 2014. The increase in CETL for the EMAAC LDA is mainly due to a 350 MW reduction in the size of a merchant transmission project located in northern New Jersey (merchant transmission queue number O66) and a change in the load distribution profile of the EMAAC LDA.

The Price Impacts of Constraints in the RPM Market

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

There was one locationally binding constraint in the 2014/2015 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, and Pepco used in the 2014/2015 RPM Base Residual Auction were significantly higher than the values used in the 2013/2014 RPM Base Residual Auction. The CETL values for PSEG, PSEG North, and DPL South used in the 2014/2015 RPM Base Residual Auction were slightly lower than the values used in the 2013/2014 RPM Base Residual Auction.

---

[68] See PJM "2014/2015 RPM Base Residual Auction Planning Period Parameters," (February 2, 2011) <http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/20110102-rpm-bra-planning-parameters-2014-2015.ashx> (February 2, 2011).

Table 19 shows the results if the market clearing used the CETL values from the 2013/2014 RPM Base Residual Auction. 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 $119.14 per MW-day, and the clearing quantity would have increased to 150,094.6 MW. The MAAC clearing price for Limited Resources would have increased to $141.60 per MW-day, and the clearing quantity would have decreased to 5,494.5 MW. The MAAC clearing price for Extended Summer and Annual Resources would have increased to $151.60 per MW-day, and the clearing quantity would have increased to 62,489.3 MW. The EMAAC import limit would have been a binding constraint. The EMAAC clearing price for Limited Resources would have increased to $150.00 per MW-day, and the clearing quantity would have decreased to 2,283.5 MW. The EMAAC clearing price for Extended Summer and Annual Resources would have increased to $160.00 per MW-day, and the clearing quantity would have increased to 30,841.7 MW. The PSEG North clearing price for Limited Resources would have remained the same at $213.97 per MW-day, and the clearing quantity would have increased to 369.8 MW. The PSEG North clearing price for Extended Summer and Annual Resources would have been $223.97 per MW-day, and the clearing quantity would have decreased to 3,252.4 MW.

Based on actual auction clearing prices and quantities and make-whole MW, total RPM market revenues for the 2014/2015 RPM Base Residual Auction were $7,258,389,284. If the market clearing used the CETL values from the 2013/2014 RPM Base Residual Auction, total RPM market revenues for the 2014/2015 RPM Base Residual Auction would have been $7,498,575,916, a difference of $240,186,632. The change in CETL values resulted in a reduction in auction revenues of three percent compared to the total based on the prior CETL values.

Composition of the Steeply Sloped Portion of the Supply Curve

Table 13 shows the composition of the offers on the steeply sloped portion of the total RTO supply curve from $35.00 per MW-day up to and including the highest offer of $1,000.00 per MW-day. DR and EE offers were 24.8 percent of the offers greater than $35.00 per MW-day. Oil or gas steam, combustion turbines and subcritical/supercritical coal units made up 72.7 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 planning 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 and Minimum Resource Requirements. The stated rationale is that this provides for short lead time resource procurement in incremental auctions for the given delivery year. For the 2014/2015 BRA, the 2.5 percent reduction resulted in the removal of 3,708.1 MW from the RTO demand curve and Minimum Resource Requirements.[69] For comparison purposes, in the 2011/2012 BRA, removal of the ILR forecast from the reliability requirement resulted in a reduction in demand of 1,593.8 MW, or 1.2 percent of the reliability requirement of 130,658.7 MW.

Table 14 shows the results if the demand curves and Minimum Resource Requirements had not been reduced by the 2.5 percent Short-Term Resource Procurement Target and everything else had remained the same. All binding constraints would have remained the same. The RTO clearing price for Limited Resources would have increased to $142.65 per MW-day, and the clearing quantity would have decreased to 11,846.2 MW. The RTO clearing price for Extended Summer and Annual Resources would have increased to $142.69 per MW-day, and the clearing quantity would have increased to 141,516.9 MW. The MAAC clearing price for Limited Resources would have increased to $150.00 per MW-day, and the clearing quantity would have decreased to 5,385.8 MW. The MAAC clearing price for Extended Summer and Annual Resources would have increased to $160.00 per MW-day, and the clearing quantity would have increased to 62,922.6 MW. The PSEG North clearing price for Limited Resources would have increased to $215.00 per MW-day, and the clearing quantity would have increased to 347.6 MW. The PSEG North clearing price for Extended Summer and Annual Resources would have remained the same at $225.00 per MW-day, and the clearing quantity would have increased to 3,605.1 MW.

The conclusion is that the removal of 2.5 percent of demand significantly reduced the clearing prices and quantities for most RPM markets. There was no change in the clearing price for the PSEG North LDA, except that the clearing price for Limited DR was slightly lower as a result of the 2.5 percent demand reduction. 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 2014/2015 RPM Base Residual Auction were $7,258,389,284. If the VRR curves and Minimum Resource Requirements had not been reduced by the Short-Term Resource Procurement Target, total RPM market revenues for the 2014/2015 RPM Base Residual Auction would have been $8,494,547,168, an increase of $1,236,157,884, or 17 percent, compared to the actual results.

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

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 2.5 Percent Holdback Rule is not counter to the interests of DR. Most DR clears in the BRA where prices have been substantially higher than in the IAs. Price suppression is a barrier to the entry of new DR resources in exactly the same way that it is a barrier to the entry of new generation resources. In the 2014/2015 BRA, the result of reducing demand by 2.5 percent was to reduce prices in the eastern part of PJM, except PSEG North which was unchanged, 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 2014/2015 BRA:[70, 71]

- **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 reduction in electric energy consumption during peak periods that is not reflected in the peak load forecast for the delivery year, and that is fully implemented at all times during the

70 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.

71 Interruptible load for reliability (ILR) is an interruptible load resource that is not offered in 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.

relevant delivery year, without any requirement of notice, dispatch, or operator intervention.[72]

Effective with the 2014/2015 delivery year, there are three types of Demand Resource products incorporated in the RPM market design:[73, 74]

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

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

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

Table 15 shows offered and cleared capacity from Demand Resources and Energy Efficiency Resources in the 2014/2015 RPM Base Residual Auction compared to the 2013/2014 RPM Base Residual Auction. DR offers increased from 12,952.7 MW in the 2013/2014 BRA to 15,545.6 MW in the 2014/2015 BRA, an increase of 2,592.9 or 20.0 percent.

Table 16 shows offered and cleared MW for Demand Resources by LDA and offer/product type in the 2014/2015 RPM Base Residual Auction. Of the 6,029.3 MW of non-coupled DR offers, 5,173.8 MW were for the Limited DR product. Of the possible DR coupling scenarios, the most frequently used was the Annual, Extended Summer,

---

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

73 134 FERC ¶ 61,066 (2011).

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

and Limited DR coupling group, with about 9,000 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 17 shows the weighted average prices for DR by LDA and offer/product type. As would be expected, given their relative values, for the coupled DR offers, the offers for Annual DR were greater than the offers for Extended Summer DR which were greater than the offers for Limited DR. In addition, the Capacity Market Seller must specify a sell offer price of at least $0.01 per MW-day more for the less limited DR product type within a coupled segment group.

In the absence of data on the marginal cost of providing DR and EE, it is difficult to determine whether such resources are offered at levels equal to, greater than or less than marginal cost. If such resources are offered at prices in excess of marginal cost, the result would be prices greater than competitive levels. If such resources are offered at prices less than marginal cost, the result would be prices less than competitive levels. Both potential outcomes are of significant concern. The RPM rules exempt DR and EE resources from market power mitigation 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 resources. Generation resources are obligated to provide capacity every hour of the year if called.

Table 18 shows the results if only generation and annual DR were offered in the 2014/2015 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 $154.87 per MW-day, and the clearing quantity would have decreased to 149,420.6 MW. The MAAC clearing price would have increased to $202.80 per MW-day, and the clearing quantity would have decreased to 67,176.0 MW. The PSEG North clearing price would have remained the same at $225.00 per MW-day, and the clearing quantity would have decreased to 3,807.9 MW.

Based on actual auction clearing prices and quantities and make-whole MW, total RPM market revenues for the 2014/2015 RPM Base Residual Auction were $7,258,389,284. If only generation and annual DR were offered in the 2014/2015 RPM Base Residual Auction, total RPM market revenues for the 2014/2015 RPM Base Residual Auction would have been $9,631,126,037, an increase of $2,372,736,753, or 33 percent, compared to the actual results.

Demand side resources had a significant impact on the outcome of the 2013/2014 BRA.

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 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 EPA MACT Emissions Standards

The U.S. Environmental Protection Agency (EPA) issued, on March 16, 2011, a notice of proposed rulemaking (NOPR) in a proceeding to promulgate final 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 12(d) of the Clean Air Act. The MMU stated that the March 16th NOPR 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 as proposed in the March 16th NOPR.[75, 76]

Table 20 shows the results if the APIR associated with the pending EPA MACT emissions standards, 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 $94.26 per MW-day, and the clearing quantity would have increased to 150,564.2 MW. The MAAC clearing price for Limited Resources would have decreased to $102.50 per MW-day, and the clearing quantity would have increased to 6,000.5 MW. The MAAC clearing price for Extended Summer and Annual Resources would have decreased to $105.00 per MW-day, and the clearing quantity would have remained the same at 61,255.3 MW. The EMAAC import limit would have been a binding constraint. The EMAAC clearing price for Limited Resources would have increased to $128.35 per MW-day, and the clearing quantity would have increased to 2,497.0 MW. The EMAAC clearing price for Extended Summer and Annual Resources would have decreased to $133.41 per MW-day, and the clearing quantity would have decreased to 29,670.7 MW. The PSEG North clearing price for Limited Resources would have increased to $222.50 per MW-day, and the clearing quantity would have increased to 398.6 MW. The PSEG North clearing price for Extended Summer and Annual Resources would have remained the same at $225.00 per MW-day, and the clearing quantity would have decreased to 3,411.6 MW.

Based on actual auction clearing prices and quantities and make-whole MW, total RPM market revenues for the 2014/2015 RPM Base Residual Auction were $7,258,389,284. If the APIR associated with the pending EPA MACT emissions standards which were not previously submitted were removed, total RPM market revenues for the 2014/2015 RPM Base Residual Auction would have been $5,897,269,210, a reduction of $1,361,120,074, or 19 percent, compared to the total based on actual results. The impact of including MACT

---

75 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).

76 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).

requirements in APIR was to increase total market revenues by $1,361,120,074, or 23 percent.

Tables and Figures for RTO Market

Table 6 RTO offer statistics: 2014/2015 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	186,341.5	174,108.1		
DR capacity	20,608.1	21,295.9		
EE capacity	806.5	831.8		
Total internal RTO capacity	207,756.1	196,235.8		
FRR	(33,612.7)	(30,661.5)		
Imports	4,299.4	4,055.5		
RPM capacity	178,442.8	169,629.8		
Exports	(1,243.1)	(1,228.1)		
FRR optional	(2,545.9)	(2,088.0)		
Excused generation	(690.1)	(594.1)		
Excused DR and EE	(5,063.6)	(5,232.2)		
Available	168,900.1	160,487.4	100.0%	100.0%
Generation offered	153,048.1	144,108.8	90.6%	89.8%
DR offered	15,043.1	15,545.6	8.9%	9.7%
EE offered	806.5	831.9	0.5%	0.5%
Total offered	168,897.7	160,486.3	100.0%	100.0%
Unoffered	2.4	1.1	0.0%	0.0%
Cleared in RTO		149,278.4		93.0%
Cleared in LDAs		696.3		0.4%
Total cleared		149,974.7		93.4%
Make-whole		112.6		0.1%
Uncleared generation		8,962.0		5.6%
Uncleared DR		1,427.2		0.9%
Uncleared EE		9.8		0.0%
Total uncleared		10,399.0		6.5%
Reliability requirement		148,323.1		
Total cleared plus make-whole		150,087.3		
Short-Term Resource Procurement Target		3,708.1		
Net excess/(deficit)		5,472.3		
Resource clearing price for Limited Resources ($ per MW-day)		$125.47		
Resource clearing price for Extended Summer Resources ($ per MW-day)		$125.99		
Resource clearing price for Annual Resources ($ per MW-day)		$125.99		
Preliminary zonal capacity price ($ per MW-day)		$125.94	A	
Base zonal CTR credit rate ($ per MW-day)		$0.00	B	
Preliminary net load price ($ per MW-day)		$125.94	A-B	

Table 7 Capacity modifications (ICAP): 2014/2015 RPM Base Residual Auction[77, 78]

	ICAP (MW)		
	RTO	MAAC	PSEG North
Generation increases	1,595.8	1,228.7	2.4
Generation decreases	(1,567.1)	(468.8)	(2.7)
Capacity modifications net increase/(decrease)	28.7	759.9	(0.3)
DR increases	19,854.8	12,180.8	708.8
DR decreases	(13,132.4)	(5,739.0)	(510.1)
DR modifications increase/(decrease)	6,722.4	6,441.8	198.7
EE increases	277.6	129.8	0.0
EE decreases	(229.5)	(75.9)	(0.6)
EE modifications increase/(decrease)	48.1	53.9	(0.6)
Net capacity/DR/EE modifications increase/(decrease)	6,799.2	7,255.6	197.8
DEOK generation	5,067.9		
DEOK DR	286.8		
DEOK EE	0.0		
Net internal capacity increase/(decrease)	12,153.9	7,255.6	197.8

77 Only cap mods, DR mods, and EE mods that had a start date on or before June 1, 2013 are included.

78 The total internal RTO capacity for the 2013/2014 BRA was 195,602.2 MW ICAP and 184,647.0 MW UCAP. These values differ from the values of 195,633.4 MW ICAP and 184,678.2 MW UCAP reported in the "Analysis of the 2013/2014 RPM Base Residual Auction Revised and Updated" (September 20, 2010) due to a correction in the modeling of a resource.

Table 8 Capacity modifications (UCAP): 2014/2015 RPM Base Residual Auction

	UCAP (MW)		
	RTO	MAAC	PSEG North
Generation increases	1,513.9	1,160.4	2.4
Generation decreases	(1,459.2)	(451.7)	(1.4)
Capacity modifications net increase/(decrease)	54.7	708.7	1.0
DR increases	20,517.3	12,587.4	732.4
DR decreases	(13,577.3)	(5,933.6)	(527.4)
DR modifications increase/(decrease)	6,940.0	6,653.8	205.0
EE increases	285.1	133.1	0.0
EE decreases	(235.7)	(77.5)	(0.6)
EE modifications increase/(decrease)	49.4	55.6	(0.6)
Net capacity/DR/EE modifications increase/(decrease)	7,044.1	7,418.1	205.4
EFORd effect	(271.7)	(248.0)	25.5
DR and EE effect	(0.4)	0.0	0.0
DEOK generation	4,520.3		
DEOK DR	296.5		
DEOK EE	0.0		
Net internal capacity increase/(decrease)	11,588.8	7,170.1	230.9

Table 9 Cleared MW by zone and resource type/fuel source: 2014/2015 RPM Base Residual Auction[79]

	Cleared UCAP (MW)										
Zone	DR	EE	Coal	Gas	Hydroelectric	Nuclear	Oil	Solar	Solid Waste	Wind	Total
AECO	205.4	0.7	726.0	640.2	0.0	0.0	346.4	16.1	0.0	0.0	1,934.8
AEP	1,635.1	9.2	1,641.0	3,499.7	58.4	85.1	0.0	0.0	0.0	200.9	7,129.4
APS	886.8	5.5	5,320.0	1,731.4	76.7	0.0	0.0	0.0	0.0	103.7	8,124.1
ATSI	955.7	2.7	3,738.0	2,024.4	0.0	2,004.1	216.1	0.0	0.0	0.0	8,941.0
BGE	1,341.3	118.4	1,222.4	503.0	0.0	1,663.5	606.4	0.0	54.5	0.0	5,509.5
ComEd	1,535.7	546.2	5,527.6	7,668.8	0.0	9,903.4	175.5	0.0	0.0	260.3	25,617.5
DAY	231.9	3.7	1,269.4	874.7	0.0	0.0	45.9	0.4	0.0	0.0	2,426.0
DEOK	54.6	0.0	1,036.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,091.4
DLCO	222.3	3.1	595.4	208.5	0.0	1,753.9	13.5	0.0	0.0	0.0	2,796.7
Dominion	1,359.5	52.1	5,761.9	7,715.8	3,531.3	3,457.6	1,617.5	3.2	157.2	0.0	23,656.1
DPL	391.5	6.8	272.1	2,716.9	0.0	0.0	910.4	0.0	0.0	0.0	4,297.7
EXT	0.0	0.0	1,796.5	975.0	245.0	0.0	0.0	0.0	0.0	0.0	3,016.5
JCPL	444.0	2.0	0.0	2,406.3	393.8	586.5	304.7	5.2	10.0	0.0	4,152.5
Met-Ed	398.4	4.1	688.5	1,994.2	17.9	796.8	221.5	0.0	75.6	0.0	4,197.0
PECO	830.5	6.6	0.0	3,282.9	1,630.3	4,505.8	774.3	1.0	99.3	0.0	11,130.7
PENELEC	437.7	3.6	5,786.3	302.6	435.4	0.0	51.0	0.0	40.4	100.8	7,157.8
Pepco	893.1	42.9	2,479.9	788.6	0.0	0.0	1,360.3	0.0	49.8	0.0	5,614.6
PPL	1,299.5	9.7	3,563.4	2,117.6	701.4	2,476.9	1,913.3	0.0	31.6	29.7	12,143.1
PSEG	964.2	4.8	813.0	5,288.5	1.9	3,393.3	377.9	19.7	143.8	0.0	11,007.1
RECO	31.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	31.2
Total	14,118.4	822.1	42,238.2	44,739.1	7,092.1	30,626.9	8,934.7	45.6	662.2	695.4	149,974.7

Table 10 Uncleared generation offers by technology type and age: 2014/2015 RPM Base Residual Auction

	Uncleared UCAP (MW)	
Technology Type	Less Than or Equal to 40 Years Old	Greater than 40 Years Old
Combined cycle	645.8	0.0
Combustion turbine	98.8	213.7
Oil or gas steam	125.9	440.7
Subcritical/supercritical coal	1,994.9	5,442.2
Other	0.0	0.0
Total	2,865.4	6,096.6

79 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, 3,424.1 MW of the 11,007.1 cleared MW in the PSEG Zone were modeled and cleared in the EMAAC LDA.

Table 11 Uncleared generation resources in multiple auctions

Technology	2014/2015 Uncleared UCAP (MW)	2014/2015 Number of Resources	2013/2014 Results for Same Set of Resources Uncleared UCAP (MW)	2013/2014 Results for Same Set of Resources Number of Resources	2012/2013 Results for Same Set of Resources Uncleared UCAP (MW)	2012/2013 Results for Same Set of Resources Number of Resources
Combined cycle	645.8	2	0.0	0	0.0	0
Combustion turbine	312.5	6	12.2	2	0.0	0
Oil or gas steam	566.6	5	227.1	3	283.5	3
Subcritical/supercritical coal	7,437.1	46	1,174.7	14	230.5	5
Other	0.0	0	0.0	0	0.0	0
Total	8,962.0	59	1,414.0	19	514.0	8

Table 12 PJM LDA CETL and CETO Values: 2013/2014 and 2014/2015 RPM Base Residual Auctions

	2013/2014			2014/2015			Change			
	CETO	CETL	CETL to CETO Ratio	CETO	CETL	CETL to CETO Ratio	CETO MW	CETO Percentage	CETL MW	CETL Percentage
MAAC	4,190.0	4,460.0	106%	2,020.0	5,694.0	282%	(2,170.0)	(52%)	1,234.0	28%
EMAAC	7,050.0	7,095.0	101%	5,790.0	8,189.0	141%	(1,260.0)	(18%)	1,094.0	15%
SWMAAC	5,740.0	6,724.9	117%	5,420.0	7,718.5	142%	(320.0)	(6%)	993.6	15%
PSEG	5,950.0	5,868.4	99%	4,880.0	5,720.7	117%	(1,070.0)	(18%)	(147.7)	(3%)
PSEG North	2,620.0	2,570.0	98%	2,110.0	2,372.0	112%	(510.0)	(19%)	(198.0)	(8%)
DPL South	1,350.0	2,123.0	157%	1,410.0	1,925.0	137%	60.0	4%	(198.0)	(9%)
Pepco	4,030.0	4,483.0	111%	3,500.0	5,606.3	160%	(530.0)	(13%)	1,123.3	25%

Table 13 Offers greater than $35.00 per MW-day on total RTO supply curve: 2014/2015 RPM Base Residual Auction[80]

Technology/Resource Type	Offered UCAP (MW)	Percent of Offers
Subcritical/supercritical coal	13,048.8	48.4%
Oil or gas steam	4,562.9	16.9%
Demand Resource coupled	3,823.7	14.2%
Demand Resource non-coupled	2,808.9	10.4%
Combustion turbine	1,971.2	7.3%
Combined cycle	650.6	2.4%
Other generation	45.1	0.2%
Energy Efficiency Resource	40.9	0.2%
Total	26,952.1	100.0%

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

Table 14 Impact of Short-Term Resource Procurement Target: 2014/2015 RPM Base Residual Auction

		Actual Auction Results		Without 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	$125.47	12,165.9	$142.65	11,846.2
	Extended Summer	$125.99	1,441.0	$142.69	1,971.6
	Annual	$125.99	136,367.8	$142.69	139,545.3
MAAC	Limited	$125.47	5,920.7	$150.00	5,385.8
	Extended Summer	$136.50	1,076.8	$160.00	1,796.6
	Annual	$136.50	60,178.5	$160.00	61,126.0
PSEG North	Limited	$213.97	340.7	$215.00	347.6
	Extended Summer	$225.00	97.1	$225.00	115.5
	Annual	$225.00	3,379.7	$225.00	3,489.6

Table 15 DR and EE statistics by LDA: 2013/2014 and 2014/2015 RPM Base Residual Auctions[81]

		2013/2014 BRA		2014/2015 BRA		Change in UCAP	
LDA		ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)	MW	Percentage
RTO	DR offered	12,528.7	12,952.7	15,043.1	15,545.6	2,592.9	20.0%
RTO	EE offered	733.4	756.8	806.5	831.9	75.1	9.9%
RTO	DR cleared	8,983.5	9,281.9	13,663.8	14,118.4	4,836.5	52.1%
RTO	EE cleared	658.7	679.4	796.9	822.1	142.7	21.0%
MAAC	DR offered	5,678.7	5,871.1	8,140.7	8,413.8	2,542.7	43.3%
MAAC	EE offered	147.9	152.0	201.8	207.6	55.6	36.6%
MAAC	DR cleared	5,682.3	5,871.1	7,003.5	7,236.8	1,365.7	23.3%
MAAC	EE cleared	147.9	152.0	193.9	199.6	47.6	31.3%
EMAAC	DR offered	2,380.7	2,461.3	3,353.5	3,466.6	1,005.3	40.8%
EMAAC	EE offered	23.8	23.9	24.9	25.1	1.2	5.0%
EMAAC	DR cleared	2,382.1	2,461.3	2,774.5	2,866.8	405.5	16.5%
EMAAC	EE cleared	23.8	23.9	20.7	20.9	(3.0)	(12.6%)
SWMAAC	DR offered	1,595.8	1,649.8	2,393.7	2,473.4	823.6	49.9%
SWMAAC	EE offered	107.0	110.6	157.3	162.6	52.0	47.0%
SWMAAC	DR cleared	1,596.8	1,649.8	2,162.1	2,234.4	584.6	35.4%
SWMAAC	EE cleared	107.0	110.6	156.0	161.3	50.7	45.8%
DPL South	DR offered	140.6	145.6	253.7	262.3	116.7	80.2%
DPL South	EE offered	2.0	2.0	5.0	5.0	3.0	150.0%
DPL South	DR cleared	140.7	145.6	213.9	220.9	75.3	51.7%
DPL South	EE cleared	2.0	2.0	5.0	5.0	3.0	150.0%
PSEG	DR offered	1,082.6	1,119.2	1,102.7	1,140.1	20.9	1.9%
PSEG	EE offered	7.3	7.4	6.8	6.8	(0.6)	(8.1%)
PSEG	DR cleared	1,083.3	1,119.2	933.0	964.2	(155.0)	(13.8%)
PSEG	EE cleared	7.3	7.4	4.8	4.8	(2.6)	(35.1%)
PSEG North	DR offered	510.1	527.4	479.8	496.2	(31.2)	(5.9%)
PSEG North	EE offered	0.6	0.6	0.0	0.0	(0.6)	(100.0%)
PSEG North	DR cleared	510.4	527.4	429.1	443.3	(84.1)	(15.9%)
PSEG North	EE cleared	0.6	0.6	0.0	0.0	(0.6)	(100.0%)
Pepco	DR offered	529.6	547.3	989.9	1,022.5	475.2	86.8%
Pepco	EE offered	34.6	35.8	41.8	43.3	7.5	20.9%
Pepco	DR cleared	529.9	547.3	864.3	893.1	345.8	63.2%
Pepco	EE cleared	34.6	35.8	41.4	42.9	7.1	19.8%

81 The maximum capacity within a coupled Demand Resource group was assumed in the offered capacity values reported for the 2014/2015 BRA.

Table 16 Offered and cleared DR by LDA and offer/product type: 2014/2015 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	515.2	0.0	0.0	482.6	0.0	0.0
RTO	Non-coupled	Extended Summer	0.0	340.3	0.0	0.0	251.5	0.0
RTO	Non-coupled	Limited	0.0	0.0	5,173.8	0.0	0.0	5,020.3
RTO	Coupled	Annual and Extended Summer	0.0	0.0	0.0	0.0	0.0	0.0
RTO	Coupled	Annual and Limited	0.0	0.0	0.0	0.0	0.0	0.0
RTO	Coupled	Extended Summer and Limited	0.0	206.5	219.6	0.0	41.8	177.8
RTO	Coupled	Annual, Extended Summer, and Limited	8,737.8	9,051.1	9,032.6	28.9	1,147.7	6,967.8
MAAC	Non-coupled	Annual	233.8	0.0	0.0	210.4	0.0	0.0
MAAC	Non-coupled	Extended Summer	0.0	315.0	0.0	0.0	231.6	0.0
MAAC	Non-coupled	Limited	0.0	0.0	2,728.8	0.0	0.0	2,651.3
MAAC	Coupled	Annual and Extended Summer	0.0	0.0	0.0	0.0	0.0	0.0
MAAC	Coupled	Annual and Limited	0.0	0.0	0.0	0.0	0.0	0.0
MAAC	Coupled	Extended Summer and Limited	0.0	169.3	182.4	0.0	24.4	158.0
MAAC	Coupled	Annual, Extended Summer, and Limited	4,516.1	4,740.4	4,733.0	28.9	820.8	3,111.4
PSEG North	Non-coupled	Annual	6.2	0.0	0.0	5.5	0.0	0.0
PSEG North	Non-coupled	Extended Summer	0.0	20.0	0.0	0.0	15.2	0.0
PSEG North	Non-coupled	Limited	0.0	0.0	159.3	0.0	0.0	138.5
PSEG North	Coupled	Annual and Extended Summer	0.0	0.0	0.0	0.0	0.0	0.0
PSEG North	Coupled	Annual and Limited	0.0	0.0	0.0	0.0	0.0	0.0
PSEG North	Coupled	Extended Summer and Limited	0.0	9.8	11.3	0.0	0.0	11.3
PSEG North	Coupled	Annual, Extended Summer, and Limited	269.7	283.3	280.9	0.0	81.9	190.9

Table 17 Weighted-average sell offer prices for DR by LDA and offer/product type: 2014/2015 RPM Base Residual Auction

			Weighted-Average ($ per MW-day UCAP)		
LDA	Offer Type	Product Type(s)	Annual	Extended Summer	Limited
RTO	Non-coupled	Annual	$41.90		
RTO	Non-coupled	Extended Summer		$65.93	
RTO	Non-coupled	Limited			$34.91
RTO	Coupled	Annual and Extended Summer			
RTO	Coupled	Annual and Limited			
RTO	Coupled	Extended Summer and Limited		$92.05	$39.92
RTO	Coupled	Annual, Extended Summer, and Limited	$99.01	$79.33	$51.55
MAAC	Non-coupled	Annual	$60.10		
MAAC	Non-coupled	Extended Summer		$63.74	
MAAC	Non-coupled	Limited			$23.03
MAAC	Coupled	Annual and Extended Summer			
MAAC	Coupled	Annual and Limited			
MAAC	Coupled	Extended Summer and Limited		$105.25	$41.65
MAAC	Coupled	Annual, Extended Summer, and Limited	$139.39	$109.44	$68.03
PSEG North	Non-coupled	Annual	$154.20		
PSEG North	Non-coupled	Extended Summer		$149.87	
PSEG North	Non-coupled	Limited			$42.44
PSEG North	Coupled	Annual and Extended Summer			
PSEG North	Coupled	Annual and Limited			
PSEG North	Coupled	Extended Summer and Limited		$133.07	$45.01
PSEG North	Coupled	Annual, Extended Summer, and Limited	$177.98	$130.81	$75.16

Table 18 Impact of DR product types: 2014/2015 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	$125.47	12,165.9		
	Extended Summer	$125.99	1,441.0		
	Annual	$125.99	136,367.8	$154.87	149,420.6
MAAC	Limited	$125.47	5,920.7		
	Extended Summer	$136.50	1,076.8		
	Annual	$136.50	60,178.5	$202.80	65,957.5
PSEG North	Limited	$213.97	340.7		
	Extended Summer	$225.00	97.1		
	Annual	$225.00	3,379.7	$225.00	3,807.9

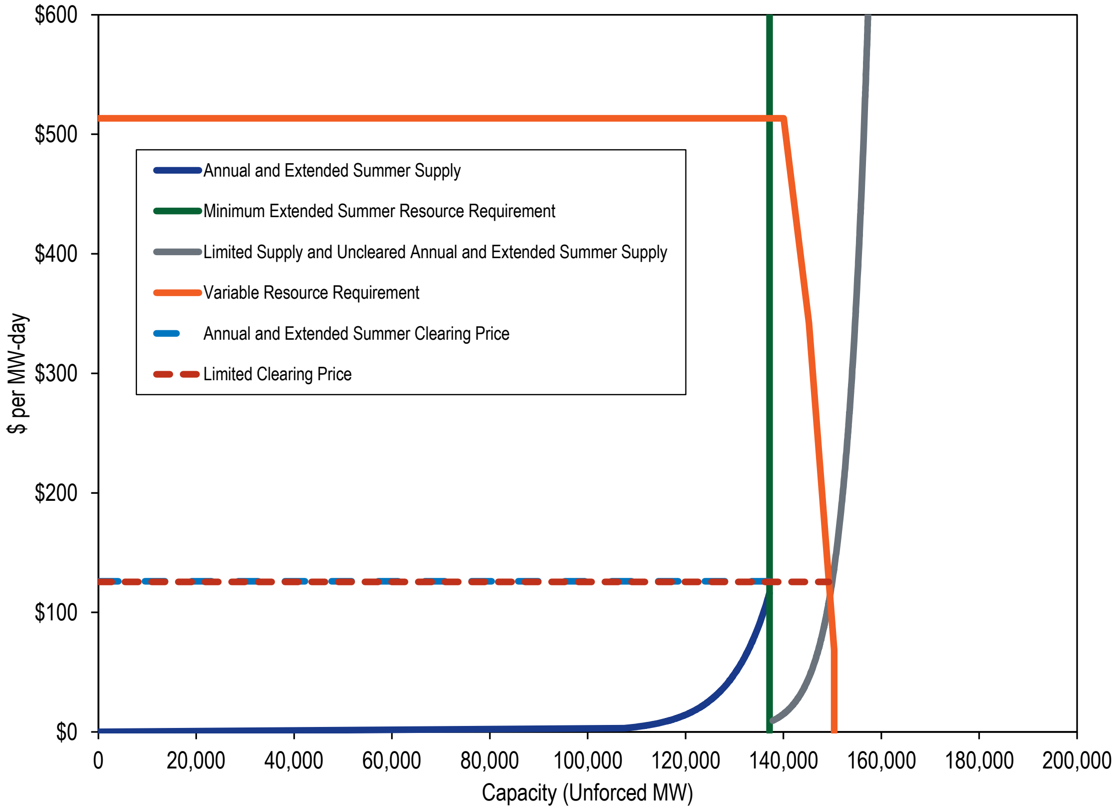
Table 19 Impact of CETL values: 2014/2015 RPM Base Residual Auction

		Actual Auction Results		Use CETL Values from 2013/2014 BRA	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Limited	$125.47	12,165.9	$119.14	12,099.7
	Extended Summer	$125.99	1,441.0	$119.14	1,713.5
	Annual	$125.99	136,367.8	$119.14	136,281.4
MAAC	Limited	$125.47	5,920.7	$141.60	5,494.5
	Extended Summer	$136.50	1,076.8	$151.60	1,693.6
	Annual	$136.50	60,178.5	$151.60	60,795.7
EMAAC	Limited	$125.47	2,322.2	$150.00	2,283.5
	Extended Summer	$136.50	442.8	$160.00	607.5
	Annual	$136.50	29,789.0	$160.00	30,234.2
PSEG North	Limited	$213.97	340.7	$213.97	369.8
	Extended Summer	$225.00	97.1	$223.97	91.9
	Annual	$225.00	3,379.7	$223.97	3,160.5

Table 20 Impact of EPA MACT emissions standards: 2014/2015 RPM Base Residual Auction

		Actual Auction Results		Remove APIR associated with pending EPA MACT emission standards	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Limited	$125.47	12,165.9	$94.26	12,133.9
	Extended Summer	$125.99	1,441.0	$94.26	812.2
	Annual	$125.99	136,367.8	$94.26	137,618.1
MAAC	Limited	$125.47	5,920.7	$102.50	6,000.5
	Extended Summer	$136.50	1,076.8	$105.00	799.3
	Annual	$136.50	60,178.5	$105.00	60,456.0
EMAAC	Limited	$125.47	2,322.2	$128.35	2,497.0
	Extended Summer	$136.50	442.8	$133.41	321.8
	Annual	$136.50	29,789.0	$133.41	29,348.9
PSEG North	Limited	$213.97	340.7	$222.50	398.6
	Extended Summer	$225.00	97.1	$225.00	64.5
	Annual	$225.00	3,379.7	$225.00	3,347.1

Figure 1 RTO market supply/demand curves: 2014/2015 RPM Base Residual Auction[82]



MAAC Market Results

Table 21 shows total MAAC offer data for the 2014/2015 RPM Base Residual Auction. All MW values stated in the MAAC section include all LDAs nested within MAAC. Total

---

82 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. 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 PSEG North. 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.

internal MAAC unforced capacity of 76,249.0 MW includes all generation 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 8, MAAC unforced internal capacity increased 7,170.1 MW from 69,078.9 MW in the 2013/2014 BRA as a result of net generation capacity modifications (708.7 MW), net DR modifications (6,653.8 MW), and net EE modifications (55.6 MW). The remaining decrease of 248.0 MW was due to higher sell offer EFORds.

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 76,249.0 MW.[83] RPM capacity was reduced by 674.0 MW of exports and 514.9 MW excused from the RPM must offer requirement as a result of significant physical operational restrictions (7.2 MW) and environmental restrictions (507.7 MW). Subtracting 4,173.6 MW of DR and EE not offered, resulted in available unforced capacity in MAAC of 70,886.5 MW.[84] After accounting for the above exceptions, 1.1 MW were not offered in the RPM Auction.

The MAAC LDA did not have a locationally binding constraint in the 2014/2015 BRA. As a result, Limited DR in MAAC received the RTO Limited Clearing Price of $125.47 per MW-day. The Minimum Extended Summer Resource Requirement was a binding constraint for MAAC in the 2014/2015 BRA. Of the 61,255.3 MW of Annual and Summer Extended resources cleared in MAAC, 60,585.9 MW were cleared in the RTO before MAAC became constrained. Once the constraint was binding, only the incremental supply located in MAAC was available to meet the incremental demand in the LDA. Of the incremental supply, 669.4 MW cleared, which resulted in a clearing price for Annual and Extended Summer Resources of $136.50 per MW-day, as shown in Figure 2. The clearing price was determined by the intersection of the incremental supply and the Minimum Extended Summer Resource Requirement. The market results in the 2014/2015 BRA included a make-whole quantity of 112.6 MW in DPL South due to the NEPA.

---

83 PJM. "Manual 18: PJM Capacity Market," Revision 13 (November 17, 2011), p. 25.

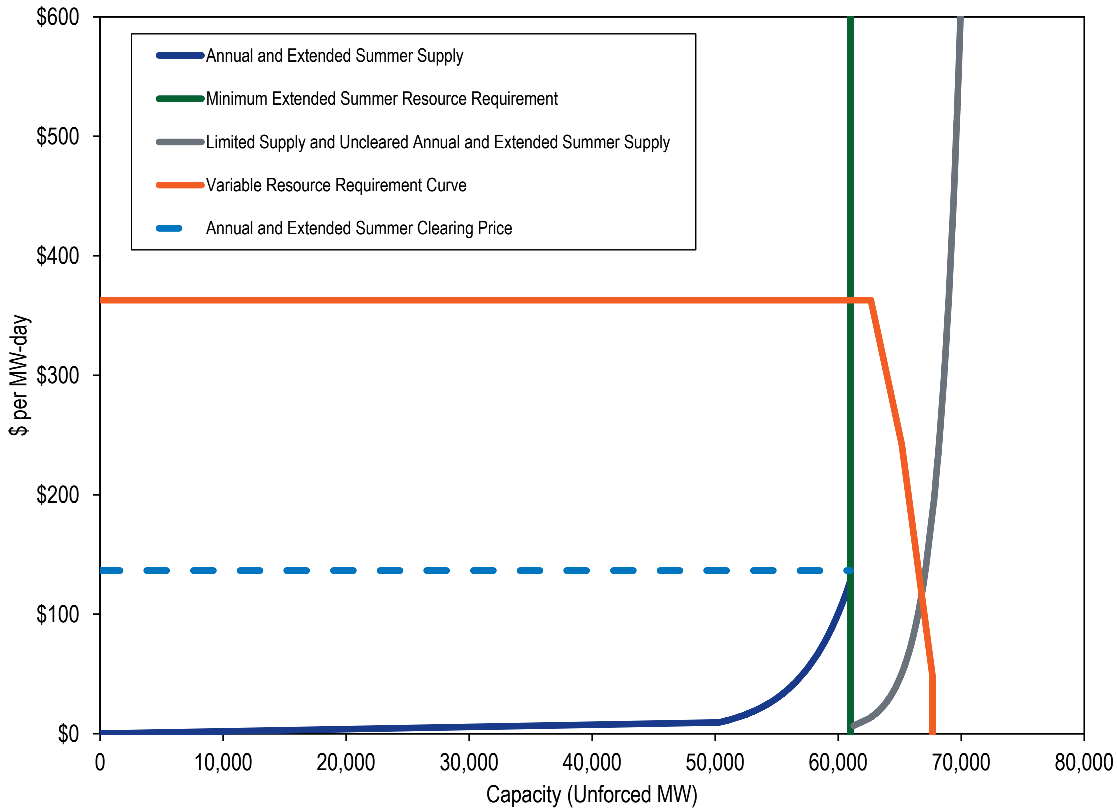
84 Unoffered DR and EE MW include PJM approved DR and EE modifications that were not offered in the auction.

Table and Figures for MAAC

Table 21 MAAC offer statistics: 2014/2015 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	67,414.5	63,454.0		
DR capacity	12,180.8	12,587.4		
EE capacity	201.8	207.6		
Total internal MAAC capacity	79,797.1	76,249.0		
FRR	0.0	0.0		
Imports	0.0	0.0		
RPM capacity	79,797.1	76,249.0		
Exports	(674.0)	(674.0)		
FRR optional	0.0	0.0		
Excused generation	(610.6)	(514.9)		
Excused DR and EE	(4,040.1)	(4,173.6)		
Available	74,472.4	70,886.5	100.0%	100.0%
Generation offered	66,127.5	62,264.0	88.8%	87.8%
DR offered	8,140.7	8,413.8	10.9%	11.9%
EE offered	201.8	207.6	0.3%	0.3%
Total offered	74,470.0	70,885.4	100.0%	100.0%
Unoffered	2.4	1.1	0.0%	0.0%
Cleared in RTO		66,479.7		93.8%
Cleared in MAAC		411.4		0.6%
Cleared in PSEG North		284.9		0.4%
Total cleared		67,176.0		94.8%
Make-whole		112.6		0.2%
Reliability requirement		72,187.0		
Total cleared plus make-whole		67,288.6		
CETL		5,694.0		
Total Resources		72,982.6		
Short-Term Resource Procurement Target		1,667.3		
Net excess/(deficit)		2,462.9		
Resource clearing price for Limited Resources ($ per MW-day)		$125.47		
Resource clearing price for Extended Summer Resources ($ per MW-day)		$136.50		
Resource clearing price for Annual Resources ($ per MW-day)		$136.50		
Preliminary zonal capacity price ($ per MW-day)		$135.25	A	
Base zonal CTR credit rate ($ per MW-day)		$0.00	B	
Preliminary net load price ($ per MW-day)		$135.25	A-B	

Figure 2 MAAC market supply/demand curves: 2014/2015 RPM Base Residual Auction[85, 86]



PSEG North Market Results

Table 22 shows total PSEG North offer data for the 2014/2015 RPM Base Residual Auction. Total internal PSEG North unforced capacity of 4,405.7 MW includes all generation 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 8, PSEG North unforced internal capacity increased 230.9 MW from 4,174.8 MW in the 2013/2014 BRA as a result of net generation capacity modifications (1.0 MW), net DR modifications (205.0 MW), and net

85 The VRR curve is reduced by the CETL and incremental demand which cleared in PSEG North, and the Minimum Extended Summer Resource Requirement is reduced by the incremental demand which cleared in PSEG North.

86 MAAC did not have a locationally binding constraint in the 2014/2015 RPM Base Residual Auction, and the MAAC clearing price for Limited Resources was set by the RTO clearing price for Limited Resources.

EE modifications (0.6 MW). The remaining increase of 25.5 MW was due to lower sell offer EFORds.

All imports offered in the auction from areas external to PJM are modeled in the RTO, so PSEG North RPM capacity was 4,405.7 MW. There were no exports from or excused generation in PSEG North. Subtracting 236.2 MW of DR and EE not offered, resulted in available unforced capacity in PSEG North of 4,169.5 MW.[87] After accounting for the above exceptions, all capacity resources in PSEG North were offered in the RPM auction.

The PSEG North LDA had a locationally binding constraint in the 2014/2015 BRA, the only one in the auction. Of the 3,817.5 MW cleared in PSEG North, 3,529.4 MW were cleared in the RTO before PSEG North became constrained. Once the constraint was binding, based on the 2,372.0 MW CETL value, only the incremental supply located in PSEG North was available to meet the incremental demand in the LDA. Of the incremental supply, 288.1 MW cleared, which resulted in a clearing price for Limited Resources of $213.97 per MW-day, as shown in Figure 3. The clearing price was determined by the intersection of the incremental supply and VRR curves.

The Minimum Extended Summer Resource Requirement was a binding constraint for MAAC and as a result Annual and Extended Summer Resources received a higher clearing price than Limited Resources in PSEG North.

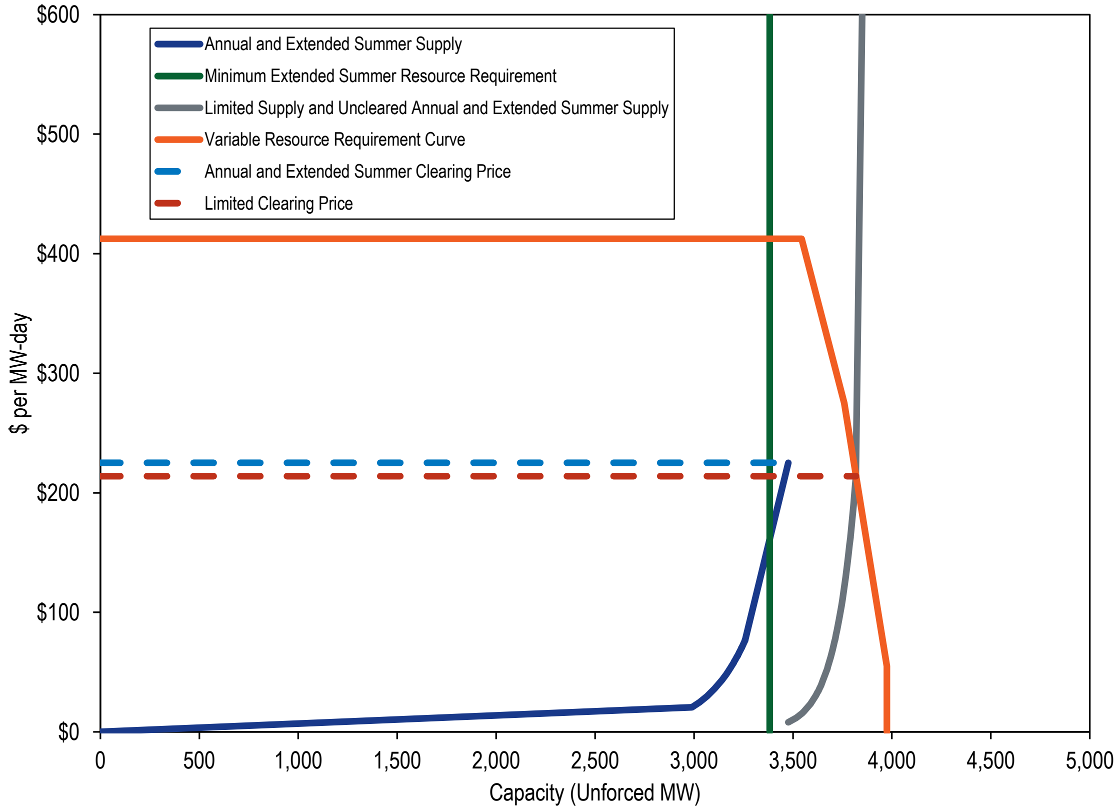
87 Unoffered DR and EE MW include PJM approved DR and EE modifications that were not offered in the auction.

Table and Figures for PSEG North

Table 22 PSEG North offer statistics: 2014/2015 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	3,965.8	3,673.3		
DR capacity	708.8	732.4		
EE capacity	0.0	0.0		
Total internal PSEG North capacity	4,674.6	4,405.7		
FRR	0.0	0.0		
Imports	0.0	0.0		
RPM capacity	4,674.6	4,405.7		
Exports	0.0	0.0		
FRR optional	0.0	0.0		
Excused generation	0.0	0.0		
Excused DR and EE	(229.0)	(236.2)		
Available	4,445.6	4,169.5	100.0%	100.0%
Generation offered	3,965.8	3,673.3	89.2%	88.1%
DR offered	479.8	496.2	10.8%	11.9%
EE offered	0.0	0.0	0.0%	0.0%
Total offered	4,445.6	4,169.5	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO		3,529.4		84.6%
Cleared in MAAC		3.2		0.1%
Cleared in PSEG North		284.9		6.8%
Total cleared		3,817.5		91.5%
Make-whole		0.0		0.0%
Reliability requirement		6,211.0		
Total cleared plus make-whole		3,817.5		
CETL		2,372.0		
Total Resources		6,189.5		
Short-Term Resource Procurement Target		134.0		
Net excess/(deficit)		112.5		
Resource clearing price for Limited Resources ($ per MW-day)		$213.97		
Resource clearing price for Extended Summer Resources ($ per MW-day)		$225.00		
Resource clearing price for Annual Resources ($ per MW-day)		$225.00		
Preliminary zonal capacity price for PSEG zone ($ per MW-day)		$179.81	A	
Base zonal CTR credit rate for PSEG zone ($ per MW-day)		$15.81	B	
Preliminary net load price for PSEG zone ($ per MW-day)		$164.00	A-B	

Figure 3 PSEG North market supply/demand curves: 2014/2015 RPM Base Residual Auction[88]



88 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.

Attachment A

Key Expected Transmission Upgrades

Upgrade ID	Description	Transmission Owner
b0025	Convert the Bergen-Leonia 138kV circuit to 230kV circuit.	PSEG
b0071	Loop the W-1323 line into the Bayway 138 kV bus	PSEG
b0074	Rebuild 12 miles of S Akron-Berks to double circuit, looping Met Ed's S Lebanon-S Reading line into Berks	PPL
b0132	Reconductor Portland - Kittatinny 230kV with 1590ACSS	JCPL
b0134	Reconductor Kittatinny – Newton 230 kV with 1590 ACSS	PSEG
b0135	Build new Cumberland – Dennis 230 kV circuit which replaces existing Cumberland – Corson 138 kV	AEC
b0136	Install Dennis 230/138 kV, Dennis 150 MVAR SVC and 50 MVAR capacitor	AEC
b0138	Install Cardiff 230/138 kV transformer and a 50 MVAR capacitor at Cardiff	AEC
b0145	Build new Essex – Aldene 230 kV cable connected through a phase angle regulator at Essex	PSEG
b0169	Build a new 230 kV section from Branchburg – Flagtown and move the Flagtown - Somerville 230 kV circuit to the new section	PSEG
b0170	Reconductor the Flagtown-Somerville-Bridgewater 230 kV circuit with 1590 ACSS	PSEG
b0171.1	Replace two 500 kV circuit breakers and two wave traps at Elroy substation to increase rating of Elroy - Hosensack 500kV	PECO
b0174	Upgrade the Portland – Greystone 230kV circuit	JCPL
b0206	Install 161Mvar capacitor at Planebrook 230kV substation	PECO
b0207	Install 161Mvar capacitor at Newlinville 230kV substation	PECO
b0208	Install 161Mvar capacitor Heaton 230kV substation	PECO
b0209	Install 2% series reactor at Chichester substation on the Chichester - Mickleton 230kV circuit	PECO
b0210	Install a new 500/230kV substation in AE area, the high side will be tapped on the Salem - East Windsor 500kV circuit and the low side will be tapped on the Churchtown - Cumberland 230kV circuit.	AEC
b0216	Black Oak Install -100/+525 MVAR dynamic reactive device	APS
b0218	Install third & forth Wylie Ridge 500/345kV transformer	APS
b0229	Install fourth Bedington 500/138kV transformer	APS
b0230	Install fourth Meadowbrook 500/138kV transformer	APS
b0238	Reconductor Doubs - Dickerson and Doubs - Aqueduct 1200MVA	APS
b0241.3	Red Lion Sub - 500/230kV work	DPL
b0244	Install a 4th Waugh Chapel 500/230kV transformer, terminate the transformer in a new 500 kV bay and operate the existing in-service spare transformer on standby and other assoc. configuration changes	BGE
b0264	Upgrade Chichester - Delco Tap 230kV and the PECO portion of the Delco Tap - Mickleton 230kV cicuit	PECO
b0265	Upgrade AE portion of Delco Tap - Mickleton 230kV circuit	AEC
b0278	Install 228MVAR capacitor at Roseland 230kV substation	PSEG
b0280.1	Install 161MVAR capacitor at Warrington 230 kV substation	PECO
b0280.2	Install 161MVAR capacitor at Bradford 230 kV substation	PECO
b0284.1	Build Airydale 500kV substation - Tap the Keystone - Juniata and Conemaugh - Juniata 500kV, connect the circuits with a breaker and half scheme, and install new 400 MVAR capapcitor	PENELEC
b0286	Install 130MVAR capacitor at Whippany 230kV substation	JCPL
b0287	Install 600MVAR Dynamic Reactive Device at Whitpain 500kV substation	PECO
b0288	Brighton Substation - Add 2nd 1000 MVA 500/230kV transformer, 2 500kV circuit breakers and miscellaneous bus work	PEPCO
b0298	Replace both Conastone 500/230kV transformer banks with larger transformers, replace Conastone 230kV breaker 500-3/2323, remove re-closing scheme of breakers #4 & #7 and other configuration changes	BGE
b0411	Install 4th 500/230kV transformer at New Freedom	PSEG
b0160	Relocate the X-2250 circuit from Hudson 1-6 bus to Hudson 7-12 bus	PSEG
b0251	Install 100 MVAR of 230kV capacitors at Bells Mill	PEPCO
b0252	Install 100 MVAR of 230kV capacitors at Bells Mill	PEPCO
b0269	Install a new 500/230kV substation in PECO, and tap the high side to Elroy - Whitpain 500kV and the low side to North Wales - Perkiomen 230kV circuit	PECO
b0272.1	Replace line trap and disconnect switch at Keeney 500kV Sub - 5025 Line Terminal Upgrade	DPL
b0289	Install 600MVAR Dynamic Reactive Device in the Whippany 230kV vicinity	JCPL
b0290	Install 400MVAR capacitor in the Branchburg 500kV vicinity	PSEG
b0311	Reconductor Idywood to Arlington 230 kV	Dominion
b0320	Create a new 230kV station that splits the 2nd Milford to Indian River 230kV line. Add a 230/69kV transformer and run a new 69kV line down to Harbeson 69kV	DPL
b0321.1	Build new Prexy to 502 Junction 500kV circuit	APS
b0321.2	Build new Prexy 500kV substation	APS
b0321.3	Build new Prexy 138kV circuits	APS
b0327	Build 2nd Harrisonburg-Valley 230 kV	Dominion
b0347.3	Build new 502 Junction 500kV substation	APS

Upgrade ID	Description	Transmission Owner
b0369	Install 100 MVAR Dynamic Reactive Device at Airydale 500kV substation	PENELEC
b0505	Reconductor the North Wales - Whitpain 230 kV circuit	PECO
b0506	Reconductor the North Wales - Hartman 230 kV circuit	PECO
b0507	Reconductor the Jarrett - Whitpain 230 kV circuit	PECO
b0319	Burches Hill Substation - Add 2nd 1000 MVA 500/230kV Transformer	PEPCO
b0328.1	Build new Meadowbrook - Loudoun 500kV circuit (65 of 81 miles)	Dominion
b0328.2	Build new Meadowbrook - Loudoun 500kV circuit (26 of 81 miles)	APS
b0328.3	Upgrade Mt Storm 500kV substation	Dominion
b0328.4	Upgrade Loudon 500kV substation	Dominion
b0329	Build Carson-Suffolk 500 kV line+Suffolk 500/230 #2 transformer+Suffolk-Thrasher 230kV line	Dominion
b0343	Replace Doubs 500/230 kV transformer #2	APS
b0344	Replace Doubs 500/230 kV transformer #3	APS
b0345	Replace Doubs 500/230 kV transformer #4	APS
b0347.1	Build new Mt. Storm - 502 Junction 500kV circuit	APS
b0347.2	Build new Mt. Storm - Meadowbrook 500kV circuit	APS
b0347.3	Build new 502 Junction 500kV substation	APS
b0347.4	Upgrade Meadowbrook 500kV substation	APS
b0357	Reconductor Buckingham - Pleasant Valley 230kV	PECO
b0367	Reconductor 230kV Quince Orchard to Dickerson circuits 33 & 35	PEPCO
b0370	Install 500 MVAR Dynamic Reactive Device at Airydale 500kV substation	PENELEC
b0375	Upgrade Dickerson - Pleasant View 230kV Circuit with reactor	PEPCO
b0376	Install 300MVAR capacitor at Conemaugh 500kV substation	PENELEC
b0423	Reconductor Readington - Branchburg 230kV circuit	PSEG
b0424	Replace wavetraps at Roseland on Readington 230kV circuit	PSEG
b0425	Reconductor Linden - Tosco 230kV circuit	PSEG
b0426	Reconductor Tosco - G22_MTX5 230kV circuit	PSEG
b0427	Reconductor Athenia - Saddle Brook 230kV circuit river section	PSEG
b0428	Replace wavetraps on Roseland - West Caldwell G 138kV circuit	PSEG
b0429	Reconductor the PSEG portion of Kittatinny - Newton 230kV circuit	PSEG
b0467.1	Reconductor the Dickerson - Pleasant View 230kV circuit	PEPCO
b0467.2	Reconductor the Dickerson - Pleasant View 230kV circuit	Dominion
b0508	Reconductor the Warrington - Hartman 230 kV circuit	PECO
b0509	Reconductor the Jarrett - Heaton 230 kV circuit	PECO
b0450	Install 150 MVAR Capacitor at Fredricksburg 230 kV	Dominion
b0469	Install 130 MVAR capacitor at West Shore 230 kV	PPL
b0472	Increase the emergency rating of Saddle Brook - Athenia 230 kV by 25% by adding forced cooling	PSEG
b0473	Move the 150 MVAR mobile capacitor from Aldene 230 kV to Lawrence 230 kV	PSEG
b0475	At North West, create two 230 kV ring buses, add two 230/115 kV transformers and create a new 115 kV station	BGE
b0478	Reconductor the four circuits from Burches Hill to Palmers Corner and replace terminal equipment	PEPCO
b0480	Rebuild Lank - Five Points 69 kV	DPL
b0489	Construct a Susquehanna - Roseland 500 kV circuit (PSEG 500 kV equipment)	PSEG
b0489.4	Install Roseland 500/230 kV transformation and upgrade 230 kV substation and switchyard	PSEG
b0501	New Brady 345 kV substation and 345 / 138 kV transformer at Brady	DL
b0502	New Underground Carson - Brady - Brunot Island 345 kV circuit	DL
b0513	Maridel to Ocean Bay (6723-1) Rebuild	DPL
b0526	Two new 230 kV circuits between Ritchie - Benning Sta. "A"	PEPCO
b0549	Install a 250 MVAR capacitor at Keystone 500 kV substation	PENELEC
b0552	Install a 50 MVAR capacitor at Altoona 230 kV substation	PENELEC
b0553	Install a 50 MVAR capacitor at Raystown 230 kV substation	PENELEC
b0555	Install a 100 MVAR capacitor at Johnstown 230 kV substation	PENELEC
b0556	Install a 50 MVAR capacitor at Grover 230 kV substation	PENELEC
b0557	Install a 75 MVAR capacitor at East Towanda 230 kV substation	PENELEC
b0559	Install a 200 MVAR capacitor at Meadow Brook 500 kV substation	APS
b0565	Install 100 MVAR capacitor at Cox's Corner 230 kV station	PSEG
b0496	Replace existing 500/230 kV transformer at Brighton	PEPCO
b0661	Install a Plano 345/138 kV Transformer	ComEd
b0663	Reconductor East Frankfort - Goodings Grove 345 kV "Red"	ComEd
b0676.1	Reconductor Doubs - Lime Kiln (#207) 230kV	APS
b0676.2	Reconductor Doubs - Lime Kiln (#231) 230kV	APS
b0717	Rebuild existing Brunner Island-West Shore 230 kV line and add a 2nd Brunner Island-West Shore 230 kV line	PPL

Upgrade ID	Description	Transmission Owner
b0721	Upgrade Oak Grove - Ritchie 23061 230 kV line	PEPCO
b0722	Upgrade Oak Grove - Ritchie 23058 230 kV line	PEPCO
b0723	Upgrade Oak Grove - Ritchie 23059 230 kV line	PEPCO
b0724	Upgrade Oak Grove - Ritchie 23060 230 kV line	PEPCO
b0749	Riverside 230kV, replace breaker & CT's on 2345 line; replace 2345 line dead-end structures at multiple buses	BGE
b0751	Add two additional breakers at Keeney 500 kV	DPL
b0752	Reybold - Lums Pond 138 kV: Replace two circuit breakers to bring the emergency rating up to 348 MVA	DPL
b0754	Rebuild 10 miles of Glasgow to Mt. Pleasant 138 kV line to bring the normal rating to 298 MVA and the emergency rating to 333 MVA	DPL
b0756	(Option D) Install a second 500/115 kV autotransformer at Chancellor 500 kV	Dominion
b0756.1	Install two 500 kV breakers at Chancellor 500 kV	Dominion
b0784	Replace wave traps on North Anna to Ladysmith 500 kV	Dominion
b0870	Rebuild Burtonsville - Sandy Spring 230 kV circuits (2314 and 2334) (0.2 miles each) to increase rating to 968N/1227E MVA	BGE
b0910	Install a second 230 kV line between Jenkins and Stanton	PPL
b1023.1	Install a 500/138 kV transformer at 502 Junction	APS
b0497	Install a second Conastone - Graceton 230 kV circuit and replace Conastone 230 kV breaker 2323/2302	BGE
b1016	Rebuild Graceton - Bagley 230 kV as double circuit line using 1590 ACSR. Terminate new line at Graceton with a new circuit breaker.	BGE
b1032.1	Construct a new 345/138kV station on the Marquis-Bixby 345kV line near the intersection with Ross - Highland 69kV	AEP
b1153	Upgrade Conemaugh 500/230 KV transformer and new line from Conemaugh-Seward 230 KV	PENELEC
b1154	Convert the West Orange 138 kV substation, the two Roseland – West Orange 138 kV circuits , and the Roseland – Sewaren 138 kV circuit from 138 kV to 230 kV	PSEG
b1155	Build a new 230 kV circuit from Branchburg to Middlesex Sw. Rack. Build a new 230 kV substation at Middlesex	PSEG
b1156	Convert the Burlington, Camden, and Cuthbert Blvd 138 kV substations, the 138 kV circuits from Burlington to Camden, and the 138 kV circuit from Camden to Cuthbert Blvd. from 138 kV to 230 kV	PSEG
b1188	Build new Brambleton 500 kV three breaker ring bus connected to the Loudoun to Pleasant View 500 kV line	Dominion
b1188.6	Install one 500/230 kV transformer and two 230 kV breakers at Brambleton	Dominion
b1221.4	Carbon Center - Carbon Center Junction & Carbon Center Junction - Bear Run conversion from 138 kV to 230 kV	APS
b1315	Convert line #64 Trowbridge to Winfall to 230 kV and install a 230 kV capacitor bank at Winfall.	Dominion

Attachment B

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 limited demand resource products and restrictions specified in credit limited offers.[89] The optimization algorithm calculates clearing prices, which are derived from the shadow prices of the binding resource requirement constraints.

For an LDA, when a transmission constraint binds and limits imports from elsewhere in PJM, higher priced offers that would not clear in an unconstrained market are required to meet demand in the LDA. The result is a constrained LDA price which is higher than the RTO price. In the BRA, the locational requirement to purchase capacity takes the form of a downward sloping piece-wise linear 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. For each constrained LDA, the auction clearing mechanism requires that the supply curve of capacity resources, including those within the LDA and imports into the LDA (from inside PJM and across the constrained interface), intersect the VRR curve. Accordingly, the shadow price associated with this constraint, called the price adder, should accurately account for the additional cost of meeting 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 MMU's approach is based on the fact that for every LDA, binding of the locational constraint means that cleared imports into the LDA equal the Capacity Emergency Transfer Limit (CETL) of the LDA. Conversely, when the locational constraint is not binding, the cleared imports should strictly be less than the CETL. The essence of the algorithm is therefore reduced to iteratively solving the mixed integer optimization problem to locate a series of points, one on each LDA's VRR curve, such that the above relationship is satisfied. 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.

89 OATT Attachment DD § 5.12(a).

Possible Reasons for Slight Differences between PJM and MMU Solutions

It is possible for the MMU's solution to the BRA optimization problem to slightly deviate 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 level. In general, lower tolerance levels are associated with longer computational times.
2. Linearization of VRR Curve: The VRR curve is a downward-sloping piece-wise linear curve. This curve is approximated by a step-wise linear function. The approximation transforms the original non-linear problem to a more tractable linear mixed integer optimization problem. Difference in the magnitude of approximation could result in slightly different solutions. A smaller step-size results in a larger number of variables in the optimization problem and therefore requires longer computational time.
3. Algorithm: The MMU's 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.

Comparison of PJM and MMU Solutions

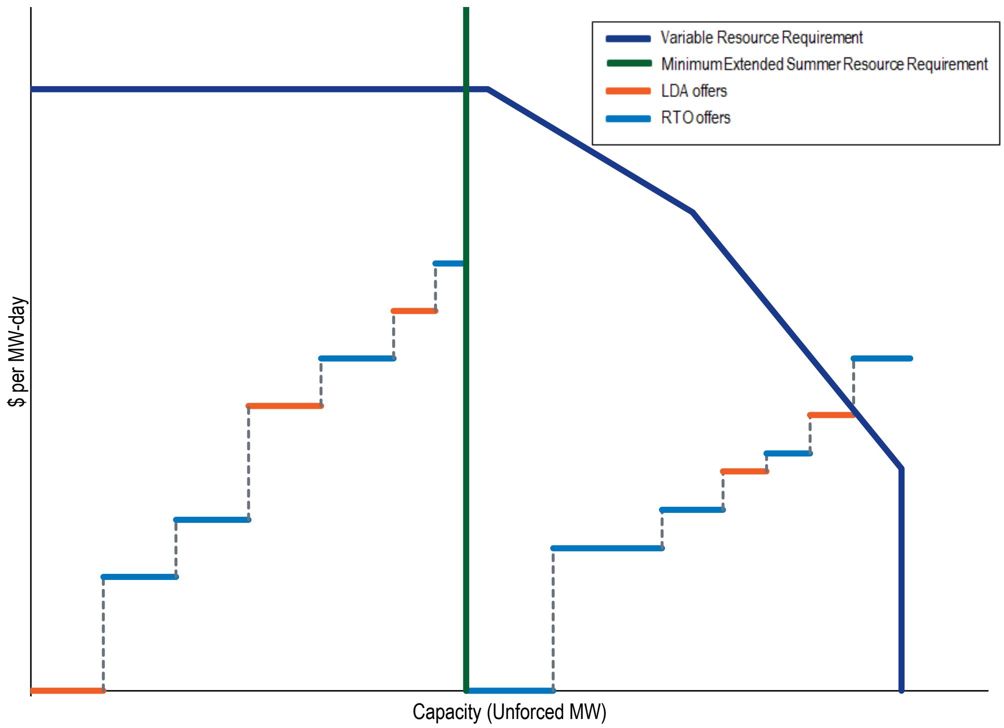
The results of the 2014/2015 Base Residual Auction and two sensitivity scenarios conducted by PJM were solved using the MMU's approach. The total MW cleared for every nested LDA using the MMU's approach is within 0.32 percent of the corresponding total MW cleared under PJM's method. The clearing prices using the MMU's approach are within 1.72 percent of the corresponding clearing prices under PJM's method.

Illustration of BRA Auction 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.

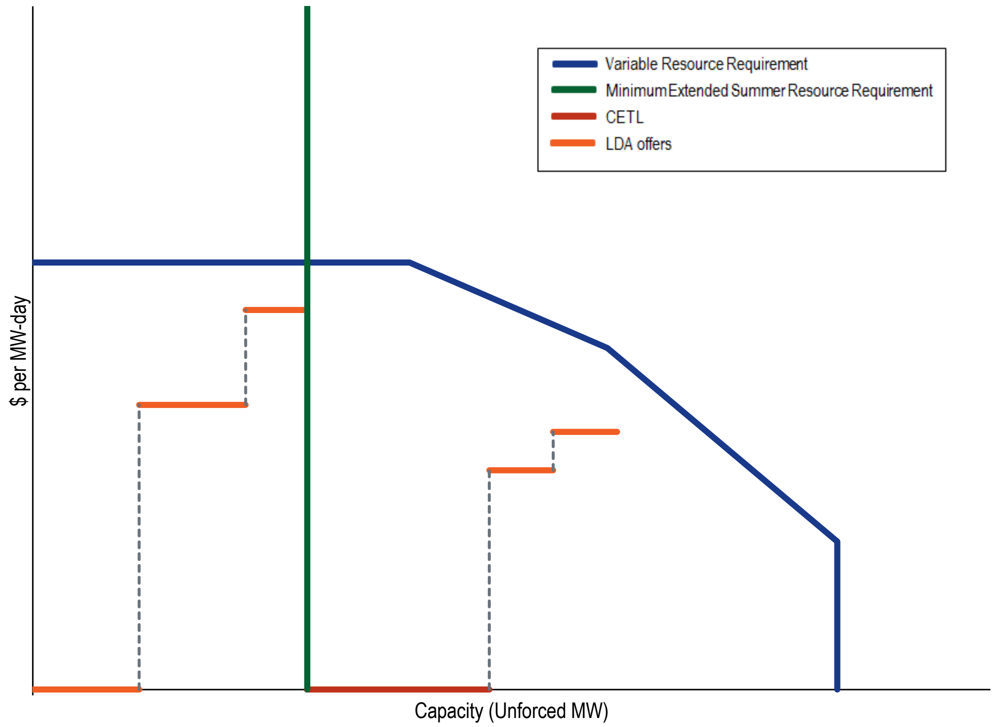
Figure 4 and Figure 5 show a solution that appears optimal from the RTO perspective, but violates the LDA requirements and constraint. The LDA's supply curve does not intersect the LDA's VRR curve.[90] To satisfy the locational requirement, higher priced offers had to be cleared to extend the LDA's supply curve until it intersects with the LDA's VRR curve. In the scenario where offered resource capacity is insufficient to meet this requirement, the clearing price is set by the intersection of the vertical line extending upwards form the last cleared resource and the VRR curve.

Figure 4 Locational resource requirement is violated: RTO



[90] For simplicity, the minimum annual resource requirement constraint is assumed to be non-binding.

Figure 5 Locational resource requirement is violated: LDA



The feasible solution shown in Figure 6 and Figure 7 is optimal and satisfies the LDA requirements and constraints. Compared to the solution shown in Figure 4 and Figure 5, a higher priced offer is cleared to satisfy the import limit constraint, i.e. the supply curve in the LDA intersects the LDA's VRR curve while imports clear at the maximum CETL. The additional cost imposed to satisfy the import limit constraint constitutes the price adder.

Figure 6 Optimal solution where locational resource requirement is not violated: RTO

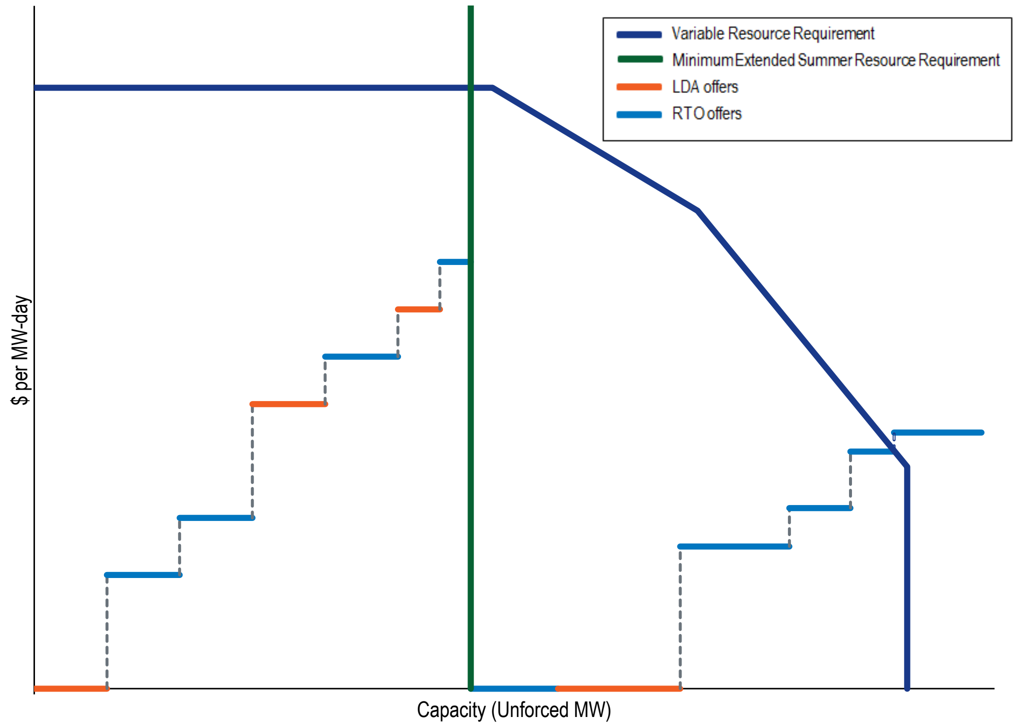


Figure 7 Optimal solution where locational resource requirement is not violated: LDA