Analysis of the 2013/2014 RPM Base Residual Auction

The Independent Market Monitor for PJM

July 14, 2010

Introduction

This report, prepared by the Independent Market Monitor for PJM (IMM or MMU), reviews the functioning of the seventh Reliability Pricing Model (RPM) Base Residual Auction (BRA) (for the 2013/2014 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); Equivalent demand forced outage rate (EFORd) rule changes; the Short-Term Resource Procurement Target; the increased default Avoidable Cost Rate (ACR) values; and Demand Resources (DR).

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 built into 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 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 RPM 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 the competitive market 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 curves and verified that the market structure tests were applied correctly. All participants in the RTO as well as MAAC, EMAAC, and Pepco RPM markets failed the three pivotal supplier (TPS) test. The result was that offer caps were applied to all sell offers of participants that did not pass the test, excluding sell offers for planned generation resources for the first delivery year, Demand Resources (DR), and Energy Efficiency (EE) resources. Prior to November 1, 2009, existing DR and EE resources were subject to mitigation in RPM Auctions.[1] The offer caps are designed to reflect the marginal cost of capacity. Based on these facts, the MMU concludes that the results of the 2013/2014 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 addressed in order to ensure that such resources provide the same value in the capacity market as generation resources.

While not as fundamental, 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. The tariff should be modified if necessary to implement this change.

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

[1] 129 FERC ¶ 61,081 (2009).

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.[2] 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."[3] A reliability requirement and a Variable Resource Requirement (VRR) curve are established for each modeled LDA. Table 1 shows the clearing prices in the 2013/2014 BRA by LDA compared to the corresponding net Cost of New Entry (CONE) values. The clearing prices were less than net CONE for each LDA except Pepco.

Table 1 Clearing prices and net CONE: 2013/2014 Base Residual Auction

LDA	Clearing Price ($/MW-day)	Net CONE ($/MW-day)
RTO	$27.73	$317.95
MAAC	$226.15	$227.20
EMAAC	$245.00	$261.06
Pepco	$247.14	$227.20

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.[4] 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 MMU to apply the 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

2 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.

3 See PJM OATT § 5.10(a)(ii) (Attachment DD: Reliability Pricing Model," Substitute First Revised Sheet No. 584 (Effective March 27, 2009)).

4 See PJM OATT § II.D.1 (Attachment M: PJM Market Monitoring Plan - Appendix," Substitute Original Sheet No. 453M.01 (Effective June 29, 2009)).

requirement.[5] 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.[6] 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.[7]

Consistent with the requirements of the Tariff, the MMU applied the PMSS two months prior to the 2013/2014 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 or opportunity cost data to the MMU for resources for which they intended to submit non-zero sell offers unless certain other conditions were met.[8] There were no provisional exceptions for the 2013/2014 Auction.

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5 The terms “PJM Region,” ”RTO Region” and “RTO” are synonymous in this report and include all capacity within the PJM footprint.

6 See PJM OATT § II.D.2 (Attachment M: PJM Market Monitoring Plan - Appendix,” Original Sheet No. 453M.01 (Effective June 29, 2009)).

7 See PJM OATT § 6.7 (Attachment DD: Reliability Pricing Model,” Third Revised Sheet No. 609 (Effective June 29, 2009)).

8 See PJM OATT § 6.7(c) (Attachment DD: Reliability Pricing Model,” Fifth Revised Sheet No. 610 (Effective November 1, 2009)).

Table 2 Preliminary Market Structure Screen results: 2013/2014[9]

	Highest Market Share	HHI	Pivotal Suppliers	Pass/Fail
RTO	14.4%	812	1	Fail
MAAC	18.1%	1101	1	Fail
EMAAC	33.0%	1992	1	Fail
SWMAAC	50.9%	4790	1	Fail
PSEG	89.7%	8069	1	Fail
Pepco	94.5%	8947	1	Fail
JCPL	28.5%	1731	1	Fail
PSEG North	89.5%	8056	1	Fail
DPL South	55.8%	3887	1	Fail

Offer Caps

The defined capacity resource owners were required to submit ACR or opportunity cost data to the MMU by two months prior to the 2013/2014 RPM Base Residual Auction. If a capacity resource owner failed the market power test for the auction, avoidable costs less PJM market revenues or opportunity costs were used to calculate offer caps for that owner's resources.

The opportunity cost option allows resource owners to input a documented export opportunity cost as the offer for the unit, subject to export limits. If the relevant RPM market clears above the opportunity cost, the unit's capacity is sold in the RPM market. If the opportunity cost is greater than the clearing price, the unit's capacity does not clear in the RPM market, and it is available for export.

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.[10] 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 also include annual capital recovery associated with investments required to

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9 The PJM Planning Period Parameters for the 2013/2014 delivery year were updated after the results of the PMSS were posted. Subsequently, JCPL was not modeled as a constrained LDA for the 2013/2014 BRA.

10 See PJM OATT § 6.8 (b) (Attachment DD: Reliability Pricing Model," First Revised Sheet No. 617 (Effective January 19, 2008)).

maintain a unit as a capacity resource. Avoidable cost based offer caps are defined to be net of net revenues from all other PJM markets and unit-specific bilateral contracts. The specific components of avoidable costs are defined in the PJM Tariff.

Default ACR Calculation Issue

Capacity resource owners could provide ACR data by providing their own unit-specific data or by selecting the default ACR values. For all auctions prior to this one, the default ACR values for both the mothball and the retirement options were calculated by the MMU based on available unit data and calculated escalation factors, in order to provide an alternative for owners that did not wish to calculate unit-specific ACR values or who believed that the default ACR values exceeded their unit-specific ACR values. The default ACR values, less net revenues, may serve as offer caps for units with market power, if unit owners select the default option.

The default ACR values through the 2012/2013 delivery year were recently included in the tariff, along with a procedure to develop ACR default values for future years on the basis of the Handy-Whitman Index (Handy-Whitman Index of Public Utility Construction Costs).[11]

Default ACR values were calculated for the first RPM auction. The default ACR values for subsequent auctions were calculated using Handy-Whitman Index values. After the Transition Period, the RPM auctions were for delivery years three years in the future, requiring that estimated default ACR values be used. The default ACR values were estimated using the most current ten year annual average rate of change in the Handy-Whitman Index applied to the base values. Each year, an additional Handy-Whitman Index value became available. Prior to estimating the default ACR values for the next RPM auction, the most current Handy-Whitman Index value was used to recalculate the ACR for the applicable year and the ten year annual average Handy-Whitman Index value was updated and used to recalculate the subsequent default ACR values. These recalculated base values did not affect the default ACR values which had already been used in auctions, but served to ensure that the base, from which future escalation would be calculated, would be accurate.

PJM's default values for 2013/2014 are overstated because PJM's approach used the annual average rate of change in the Handy-Whitman Index for the ten year period from 1999 through 2008. This annual average rate of change was used to calculate the default

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11 PJM OATT § 6.7(c) (Attachment DD: Reliability Pricing Model," Sixth Revised Sheet No. 611 (Effective November 1, 2009)); *PJM Interconnection, L.L.C.*, 129 FERC ¶61,081at P 47 (The Commission found "the revisions acceptable because they accurately state the default rates for market sellers that are subject to offer price mitigation.").

ACR values for each year from 2009/2010 through 2012/2013. However, at the time of PJM's calculation, more current Handy-Whitman Index values were available.

In order to have an accurate calculation of the 2013/2014 ACR default values, the base year values for the delivery years 2009/2010 through 2012/2013 must be calculated using the most current actual Handy-Whitman Index data rather than relying on outdated data. Unless this approach is taken each year, the estimated values will use fewer and fewer years of actual Handy-Whitman data, and the result will potentially diverge farther each year from an estimate calculated using the actual historical Handy-Whitman Index data. The method used by PJM may result in either an overstatement or an understatement of the appropriate value, depending on the relationship between the actual Handy-Whitman Index value and the estimate.

The MMU took the position that the recently revised tariff language did not unambiguously direct use of a value that was known to be incorrect and that, if it did so direct, the potential impact was sufficiently serious that action should be taken to allow use of the correct value.[12] PJM took the position that the tariff required use of a value based on a prior estimate and did not believe it appropriate to take action to modify the tariff prior to the auction that was to occur in two and a half months. PJM explained that "the specifics of this issue may in fact be a one-time situation, and that the issue may be best included in any effort to result from the Long Term Capacity Issues Symposium."[13] The MMU presented the issue to members at the February 24, 2010 meeting of the MRC and the members did not choose to act. PJM calculated and incorporated in the tariff the ACR values consistent with its view of the tariff and the approach established in compliance with Order No. 719 that PJM should calculate the default ACR values.[14]

The annual average rate of change in the Handy-Whitman Index for the most current ten year period, from 2000 through 2009, was 1.04092. Both the MMU and PJM used the factor of 1.04092 to adjust the 2012/2013 default ACR values. However, PJM applied this factor to 2012/2013 default ACR values which had been estimated using the ten year period ending in 2008 rather than using the most current Handy-Whitman Index values. The estimated values for 2012/2013 used by PJM applied an escalation factor of 1.04551 to the 2008/2009 ACR values and for each subsequent year including 2011/2012. The

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[12] MMU presentation to the PJM Markets and Reliability Committee (MRC), "Default ACR Escalation Calculation" (February 24, 2010), which can be accessed at <*http://www.pjm.com/~/media/committees-groups/committees/mrc/20100224/20100224-item-14-avoidable-cost-rate.ashx*> (84.57 KB).

[13] Minutes of the MRC meeting of February 24, 2010 at 10.

[14] See 129 FERC ¶61,250 at P 143 & n.110.

actual change in the Handy-Whitman Index in 2009 over 2008 was a reduction to 0.96980 rather than an increase. The most current ten year average rate of change in the Handy-Whitman Index was 1.04092 rather than the 1.04551 used by PJM. If the 2012/2013 default ACR values had been recalculated first, using the actual Handy-Whitman Index for 2009 rather than the estimate used by PJM and using the most current ten year average for each subsequent year, the 2013/2014 ACR values would have been significantly lower.

The result of PJM's reliance on Handy-Whitman Index data that did not incorporate the Index value for 2009 was that the default ACR values used in the 2013/2014 BRA were about nine percent higher than appropriate. Table 3 shows a comparison of the Monitoring Analytics and PJM calculated default ACR values by technology.

The MMU 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. Every prior delivery year default ACR value that had been estimated using now outdated Handy-Whitman Index data should be recalculated using the most current Handy-Whitman Index data. The failure to do so will lead to significant errors that may compound over time. The purpose of the recalculation is to ensure that the base values are accurate prior to escalation and not to modify the estimated default ACR values for the prior auctions. The tariff should be modified if necessary to ensure that the calculations are accurate and to ensure that the correct Handy-Whitman Index values are used for 2009 and every subsequent year.

The MMU's approach was used for every prior year in the calculation of default ACR values. The PJM approach was used for the first time in the 2013/2014 BRA.

Table 3 Comparison of Monitoring Analytics and PJM calculated default ACR values: 2013/2014 Base Residual Auction

Technology Type	Monitoring Analytics Calculated Default ACR Values ($/MW-Day)	PJM Calculated Default ACR Values ($/MW-Day)
Nuclear	NA	NA
Pumped Storage	$21.64	$23.64
Hydro	$73.96	$80.80
Subcritical Coal	$177.58	$193.98
Supercritical Coal	$183.46	$200.41
Waste Coal - Small	$234.18	$255.81
Waste Coal - Large	$86.61	$94.61
Wind	NA	NA
CC - Two on One Frame F Technology	$32.21	$35.18
CC - Three on One Frame E/Siemens Technology	$35.76	$39.06
CC - Three or More on One or More Frame F Technology	$27.88	$30.46
CC - NUG Cogeneration Frame B or E Technology	$119.71	$130.76
CT - First & Second Generation Aero (P&W FT 4)	$25.59	$27.96
CT - First & Second Generation Frame B	$25.29	$27.63
CT - Second Generation Frame E	$24.04	$26.26
CT - Third Generation Aero (GE LM 6000)	$58.20	$63.57
CT - Third Generation Aero (P&W FT-8 TwinPak)	$30.52	$33.34
CT - Third Generation Frame F	$24.68	$26.96
Diesel	$27.38	$29.92
Oil and Gas Steam	$67.92	$74.20

ACR Results

As shown in Table 4, 1,170 generating resources submitted offers compared to 1,133 generating resources offered in the 2012/2013 RPM Base Residual Auction, or a net increase of 37 resources. The increase in generating resources consisted of 63 ATSI resources that were not offered in the 2012/2013 BRA (11,325.4 MW), 31 new resources (1,038.2 MW), four resources that were previously entirely Fixed Resource Requirement (FRR) committed (234.3 MW), and four additional resources imported (460.1 MW). The reduction in generating resources consisted of seven retired resources (824.0 MW), two deactivated resources (66.6 MW), 49 additional resources committed fully to FRR (307.7 MW), four less planned generation resources that were not offered (249.3 MW), two additional resources excused from offering (4.2 MW), and one less external resource that was not offered (45.7 MW). In addition, there were the following retirements of resources that were either exported or excused in the 2012/2013 BRA: three steam units (125.9 MW). The publicly posted retirement and deactivation requests include Kearny 9 (17.4 MW) in PSEG North; Cromby 1 (137.6 MW), Cromby 2 (183.6 MW), Eddystone 1

(212.0 MW), and Eddystone 2 (232.6 MW) in EMAAC; and Gorsuch 1 (40.6 MW), Gorsuch 2 (41.6 MW), Gorsuch 3 (44.0 MW), Gorsuch 4 (40.3 MW), and North Branch 1 (64.0 MW) in RTO. Resources that are no longer capacity resources but do not have public notifications of future deactivations consisted of two diesel resources (2.8 MW).

The new generation capacity resources consisted of 11 solar resources (9.5 MW), 11 wind resources (245.7 MW), four combined cycle units (671.5 MW), three diesel resources (5.4 MW), one steam unit (23.8 MW), and one CT unit (82.3 MW).[15] In addition, there were the following new generation resources that were not offered in to the auction because they were either exported or entirely committed to FRR for the 2013/2014 delivery year: four wind resources (66.2 MW).

There were 426 demand resources (DR) offered compared to 233 DR resources offered in the 2012/2013 RPM Base Residual Auction. There were 128 EE resources offered compared to 53 EE resources in the 2012/2013 RPM Base Residual Auction.

The MMU calculated 700 offer caps, of which 587 were based on the technology specific default (proxy) ACR values.[16] The 2013/2014 default ACR values were escalated from the 2012/2013 ACR values by PJM using the previously estimated base year values for 2012/2013 rather than incorporating the most recent Handy-Whitman Index value for 2009 in calculating the base year value. Unit-specific offer caps were calculated for 107 units (9.1 percent) including 92 units (7.9 percent) with an Avoidable Project Investment Recovery Rate (APIR) component and 15 units (1.3 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 1,724 generation resources, 20 planned resources had uncapped offers while the remaining 450 generating resources were price takers, of which the offers for 441 resources were zero and the offers for nine resources were set to zero because no data were submitted.[17]

As shown in Table 5, the weighted-average gross ACR for units with APIR ($390.05 per MW-day) and the weighted-average offer caps, net of net revenues, for units with APIR ($134.44 per MW-day) decreased from the 2012/2013 BRA values of $464.54 per MW-day

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

16 Seven resources had both ACR based and opportunity cost based offer caps calculated.

17 Planned units are subject to mitigation only under specific conditions defined in the tariff. Some of the 20 uncapped planned units submitted zero price offers. See PJM OATT § 6.5(a)(ii) (Attachment DD: Reliability Pricing Model," Third Revised Sheet No. 607 (Effective January 31, 2010)).

and $167.62 per MW-day, due primarily to lower gross ACRs and APIR components for subcritical/supercritical coal units with APIR, offset in part by lower net revenues.

The APIR component added an average of $268.59 per MW-day to the ACR value of the APIR units compared to $351.74 per MW-day in 2012/2013.[18, 19] The highest APIR for a technology ($352.55 per MW-day) was for subcritical/supercritical coal units. The maximum APIR effect ($1,304.36 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

Offer caps for units without an APIR component, including units for which the default value was selected, decreased from $21.55 per MW-day to $14.09 per MW-day due primarily to lower weighted-average offer caps for subcritical/supercritical coal units without an APIR component and units in the other category (diesel, pumped storage, hydro, waste coal) without an APIR component.[20]

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

[19] The 92 units which had an APIR component submitted $326.7 million for capital projects associated with 10,328.3 MW of UCAP.

[20] The default ACR values include an average APIR of $1.37 per MW-day, which is the average APIR ($1.31 per MW-day) for the previously estimated default ACR values in the 2012/2013 BRA escalated using the most recent Handy-Whitman Index value.

Table 4 ACR statistics: 2013/2014 RPM Base Residual Auction

Calculation Type	Number of Resources	Percent of Generation Resources Offered
Default ACR selected	580	49.6%
ACR data input (APIR)	92	7.9%
ACR data input (non-APIR)	15	1.3%
Opportunity cost input	6	0.5%
Default ACR and opportunity cost input	7	0.6%
Generating resources with offer caps	700	59.8%
Uncapped planned generation resources	20	1.7%
Generation price takers	450	38.5%
Generation resources offered	1,170	100.0%
Uncapped demand resources	426	
Uncapped energy efficiency resources	128	
Total capacity resources offered	1,724	

Table 5 APIR statistics: 2013/2014 RPM Base Residual Auction[21, 22]

	Weighted-Average ($ per MW-day UCAP)					
	Combined Cycle	Combustion Turbine	Oil or Gas Steam	Subcritical/ Supercritical Coal	Other	Total
Non-APIR units						
ACR	$44.51	$33.30	$79.91	$212.68	$52.57	$115.83
Net revenues	$110.63	$30.53	$12.72	$364.90	$259.34	$199.44
Offer caps	$6.84	$16.36	$68.15	$9.29	$14.30	$14.09
APIR units						
ACR	NA	$49.42	$341.77	$509.95	$305.48	$390.05
Net revenues	NA	$9.18	$63.80	$459.41	$187.40	$292.92
Offer caps	NA	$40.73	$277.96	$112.30	$118.09	$134.44
APIR	NA	$25.28	$243.47	$352.55	$1.69	$268.59
Maximum APIR effect						$1,304.36

RPM Auction Results

MMU Methodology

The MMU reviewed the following inputs to and results of the 2013/2014 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 capacity resource for the period from 2007 through 2009;

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21 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.

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

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 DR and EE resources. The EFORd values in this report are the EFORd values used in the 2013/2014 RPM Base Residual Auction.

- **Exported Resources –** Verified that capacity resources exported from PJM had firm external contracts or made documented opportunity cost offers;

- **Excused Resources –** Verified the specific reasons that capacity resources were excused from offering into the auction;

- **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, 2009;

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

- **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

Only those participants that fail the market power test are subject to offer capping. As shown in Table 6, all participants in the RTO as well as MAAC, EMAAC, and Pepco RPM markets failed the TPS test.[24] The result was that offer caps were applied to all sell offers of participants that did not pass the test, excluding sell offers for planned generation resources for the first delivery year, DR, and EE resources. The supply considered in the TPS test for the RTO market includes all supply from generation resources offered at less than or equal to 150 percent of the RTO cost-based clearing price. The supply considered in the TPS test 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 demand consists of the incremental MW needed in the LDA to relieve the constraint. As a result of the fact that DR and EE resources are no longer subject to market power mitigation, such resources are not included in the TPS test.[25] The reason that it was acceptable, in the short run, to exempt DR and EE resources from market power mitigation is that physical generation resources set the price in the auctions and DR and EE resources cannot increase the price. Given that physical

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24 See the *2009 State of the Market Report for PJM* (March 11, 2010), 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.

25 129 FERC ¶ 61,081 (2009).

generation resources set the maximum auction price, without regard to DR and EE resources, it is appropriate to consider only the physical generation resources in the market structure test. The exercise of market power by DR and EE resources is still possible but the outcome would be that the reduction in price that results from the participation of DR and EE resources will be less than the reduction in price from a competitive outcome, rather than an increase in the market price.

Table 6 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.[26] MAAC/SWMAAC are presented together because SWMAAC was modeled but was not a constrained LDA in this auction. Similarly, EMAAC/PSEG/PSEG North/DPL South are presented together because PSEG, PSEG North, and DPL South were modeled but were not constrained LDAs in this auction.

Table 6 RSI Results: 2013/2014 RPM Base Residual Auction

	$RSI_{1\ 1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
RTO	0.80	0.59	87	87
MAAC/SWMAAC	0.42	0.23	9	9
EMAAC/PSEG/PSEG North/DPL South	0.25	0.00	2	2
Pepco	0.00	0.00	1	1

RTO

Table 7 shows total RTO offer data for the 2013/2014 RPM Base Residual Auction. All MW values stated in the RTO section include all nested LDAs. Nested LDAs occur when

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26 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 *2009 State of the Market Report for PJM* (March 11, 2010), Appendix L, "Three Pivotal Supplier Test" for additional discussion.

a constrained LDA is a subset of a larger constrained LDA or the RTO. For example, MAAC is nested in the RTO, as are all other LDAs, while EMAAC and Pepco are both nested in MAAC. Total internal RTO unforced capacity increased 14,724.9 MW (8.7 percent) from 169,953.3 MW in the 2012/2013 RPM BRA to 184,678.2 MW as a result of new generation (756.8 MW), the integration of the ATSI zone into PJM, capacity upgrades to existing generation and increases in DR and EE, net of derations to generation, DR and EE capacity resources. As shown in Table 9, of the 14,724.9 MW increase, 13,828.2 MW were due to the integration of the ATSI zone, -518.0 MW were net generation capacity modifications (cap mods), 1,894.1 MW were net DR modifications (DR mods), and 100.8 MW were net EE modifications.[27] A decrease of 589.3 MW (0.35 percent) was due to higher sell offer EFORds, and the increase of 9.1 MW was due to a higher Load Management UCAP conversion factor compared to the 2012/2013 BRA.[28, 29] Total internal RTO unforced capacity includes all generation resources, DR, and EE that qualified as PJM capacity resources for the 2013/2014 auction, excluding external units, and also includes owners' modifications to installed capacity ratings which are permitted under the PJM Reliability Assurance Agreement (RAA) and associated manuals.[30] 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.[31] Otherwise the owner must take an

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

28 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 2012/2013 BRA, this conversion factor was 0.950*1.0872 = 1.0328. For the 2013/2014 BRA, this factor was .957*1.0804 = 1.0339. 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.

29 See "PJM Manual 20: PJM Resource Adequacy Analysis," Revision 03 (June 1, 2007), p. 8-10 <http://www.pjm.com/~/media/documents/manuals/m20.ashx> (662.9 KB).

30 See "Reliability Assurance Agreement among Load-Serving Entities in the PJM Region," (Effective June 1, 2007), Schedule 9.

31 See "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," Revision 09 (May 1, 2010), p. 11 < http://www.pjm.com/~/media/documents/manuals/m21.ashx> (272.94 KB). The manual states "the end of the next Delivery Year."

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 164,930.0 MW compared to 149,520.1 MW in the 2012/2013 RPM Base Residual Auction.[32] FRR volumes decreased by 168.4 MW, and imports increased by 516.6 MW. RPM capacity was reduced by exports of 2,438.4 MW and 4.5 MW which were excused from the RPM must offer requirement as a result of performance concerns (2.5 MW) and other factors (2.0 MW). Exports decreased 198.7 MW, and excused generation volumes decreased 39.7 MW from the 2012/2013 RPM auction. Subtracting 945.2 MW of FRR optional volumes not offered, a decrease of 520.3 MW in FRR MW not offered from the 2012/2013 RPM Base Residual Auction, and 643.8 MW of DR and EE not offered, resulted in 160,898.1 MW that were available to be offered into the auction, an increase of 15,524.8 MW.[33, 34] After accounting for the above, all capacity resources were offered into the RPM auction.

As shown in Figure 1, the resource clearing price for the RTO was $27.73 per MW-day.

As shown in Figure 2, the RTO clearing price increased from $16.46 per MW-day in the 2012/2013 Base Residual Auction to $27.73 per MW-day in the 2013/2014 auction, consistent with the fact that demand increased by more than supply. Offered volumes increased 15,524.8 MW from 145,373.3 MW to 160,898.1 MW, while the overall RTO reliability requirement, from which the demand curve is developed, increased 16,256.3 MW from 133,732.4 MW to 149,988.7 MW.[35] The increase in the reliability requirement,

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32 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.

33 FRR entities are allowed to offer into the RPM auction excess volumes above their FRR quantities, subject to a sales cap amount. The 945.2 MW are a combination of excess volumes included in the sales cap amount which were not offered into the auction and volumes above the sales cap amount which were not permitted to offer into the auction.

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

35 The demand curve UCAP quantities are based on three points, which are ratios of the Installed Reserve Margin (IRM = 15.3 percent) times the reliability requirement, less the forecast RTO ILR obligation. For the three points, the ratios are 1.123/1.153, 1.163/1.153 and 1.203/1.153. For these three points the UCAP prices are based on factors multiplied by net

due to the inclusion of the ATSI zone in the preliminary forecast peak load, shifted the RTO market demand curve to the right.

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. The final zonal capacity price and the final CTR credit rate are calculated after the final incremental auction. As shown in Table 7, the preliminary net load price is $27.73 per MW-day in the RTO.

The Impact of the Downward Sloping Demand Curve on Cleared Prices and Quantities

As a result of the downward sloping demand curve, more capacity cleared in the market than would have cleared with a vertical demand curve equal to the reliability requirement. As shown in Table 7, the 152,743.3 MW of cleared resources for the entire RTO, which represented a reserve margin of 20.2 percent, resulted in net excess of 6,518.3 MW over the reliability requirement of 149,988.7 MW (Installed Reserve Margin (IRM) of 15.3 percent). [36, 37] Net excess increased 763.9 MW from the net excess of 5,754.4 MW in the 2012/2013 RPM auction. As shown in Figure 1, the downward sloping demand curve resulted in a price of $27.73 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.[38] A more economical 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

Cost of New Entry (CONE) divided by one minus the pool-wide EFORd. Net CONE is defined as CONE minus the energy and ancillary service revenue offset (E&AS). For the three points, the factors are 1.5, 1.0 and 0.2.

36 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.

37 The IRM decreased from 16.2 percent to 15.3 percent for the 2013/2014 delivery year.

38 See PJM OATT § 5.14(b) (Attachment DD: Reliability Pricing Model," Second Revised Sheet No. 596 (Effective January 31, 2010)).

requirement.[39] The market results in the 2013/2014 BRA included a make-whole quantity of 14.0 MW in EMAAC.

Table 10 shows cleared MW by zone and fuel source. Of the 12,952.7 MW offered by DR, 9,281.9 MW cleared (71.7 percent). Of the 756.8 MW offered by EE resources, 679.4 MW cleared (89.8 percent). Of the 147,188.6 MW offered by generation resources, 142,782.0 MW cleared (97.0 percent). Of the 152,743.3 cleared MW in the entire RTO, 25,688.6 MW (16.8 percent) cleared in ComEd, followed by 22,836.4 MW in Dominion (15.0 percent) and 11,598.2 MW (7.6 percent) in PPL. Of the 142,782.0 cleared MW from generation resources in the entire RTO, 49,270.6 MW (34.5 percent) were coal resources, followed by 45,747.7 MW (32.0 percent) from gas resources and 30,889.7 MW (21.6 percent) from nuclear resources.

The 8,140.8 MW of uncleared volumes in the entire RTO were the result of offer prices which exceeded the clearing prices. Of the 8,140.8 uncleared MW in the entire RTO, 77.4 MW were EE offers, 3,670.8 MW were DR offers, and the remaining 4,392.6 MW were generation offers. Table 11 presents details on the generation offers that did not clear.

Table 12 shows the auction results in the prior two delivery years for the generation resources that did not clear some or all MW in the 2013/2014 BRA. Of the 54 generation resources that did not clear 4,392.6 MW in the 2013/2014 BRA, 23 generation resources did not clear 1,007.2 MW in the 2012/2013 delivery year. Of those 23 generation resources that did not clear MW in the 2013/2014 and 2012/2013 delivery years, 4 resources did not clear 58.9 MW in the 2011/2012 delivery year. Thus, 1,007.2 MW of capacity did not clear in two subsequent auctions, but this did not extend to three subsequent auctions.

If the demand curve had been vertical at the reliability requirement less the Short-Term Resource Procurement Target with the same maximum price set at 1.5 times the net CONE and the RTO cleared as a single market, the clearing price would have been $33.00 per MW-day as shown in Figure 3. If the given LDAs were modeled and the demand curves had been vertical at the LDA reliability requirements less the LDA Short-Term Resource Procurement Targets, MAAC, EMAAC, and Pepco would have had binding constraints, and SWMAAC, PSEG, PSEG North, and DPL South would not have had binding constraints. The RTO would have cleared at $15.00 per MW-day as shown in Figure 4.

Based on actual auction clearing prices and quantities and make-whole MW, total RPM market revenues for the 2013/2014 delivery year were $6,708,567,045. If the demand

[39] See PJM OATT § 5.12(a) (Attachment DD: Reliability Pricing Model," Second Revised Sheet No. 594 (Effective November 13, 2009)).

curves had been vertical at the RTO and LDA reliability requirements less the Short-Term Resource Procurement Targets and the given LDAs were modeled, total RPM market revenues for the 2013/2014 delivery year would have been $4,983,766,843, a difference of $1,724,800,202 compared to the total based on actual results.

The conclusion is that the use of downward sloping demand curves for the RTO and the individual LDAs had a significant impact on the clearing prices and quantities.

The Price Impacts of Constraints in the RPM Market

As is the case in locational energy markets, 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.

The impact of constraints on relative prices was significant in the 2013/2014 BRA. There were three binding constraints in the 2013/2014 BRA which resulted in demand clearing in those LDAs which did not clear in the RTO market. The result was to shift the demand curve in the RTO market to the left along the upwardly sloping supply curve and to reduce the price in the RTO market. The price impact is the result both of the size of the shift of the demand curve and the slope of the supply curve. The larger the shift in the demand curve and the steeper the slope of the supply curve, the greater the price impact.

Figure 5 illustrates the impact of the constraints on relative prices in the 2013/2014 BRA. If no LDAs had been modeled or constrained in this auction and the RTO had cleared as a single market, the RTO would have cleared at $60.32 per MW-day. If only Pepco had been constrained, the RTO would have cleared at $54.79 per MW-day. If, in addition, EMAAC had been constrained, the RTO would have cleared at $38.10 MW-day. Finally, adding MAAC as a constrained LDA resulted in the RTO market clearing at $27.73 per MW-day. The incremental effect of adding EMAAC as a modeled LDA when no nested LDAs within EMAAC have binding constraints is greater than when nested LDAs within EMAAC have binding constraints. In the 2012/2013 BRA, DPL South and PSEG North, both nested within EMAAC, were constrained. Pepco, which is a subset of MAAC but not EMAAC, was constrained in the 2013/2014 auction, resulting in fewer incremental MW cleared in the rest of MAAC and less of an incremental effect of modeling MAAC.

Based on actual auction clearing prices and quantities and make-whole MW, total RPM market revenues for the 2013/2014 delivery year were $6,708,567,045. If the market had cleared as a single market, total RPM market revenues for the 2013/2014 delivery year would have been $3,362,918,687, a difference of $3,345,648,358 compared to the total based on actual results. If only Pepco had been constrained, total RPM market revenues for the 2013/2014 delivery year would have been $3,391,028,449, a difference of $3,317,538,596 compared to the total based on actual results. If, in addition, EMAAC had been constrained, total RPM market revenues for the 2013/2014 delivery year would have been $4,969,417,202, a difference of $1,739,149,844 compared to the total based on actual results.

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 what cleared incrementally in the constrained, nested LDAs.

Mitigated and Unmitigated Supply Curves

The unmitigated supply curve includes all submitted offers while the mitigated supply curve includes the sell offers used in clearing the market. The two curves differ where an offer was reduced to an offer cap when an owner failed the TPS test. There were 75 mitigated generating resources, including 5,842.0 MW.

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 RTO supply curve (see Figure 1) 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 39.2 percent of the offers and oil/gas steam, combustion turbines and subcritical/supercritical coal units made up 59.9 percent of the offers.

Impacts of Rule Changes Affecting EFORd

Prior to March 27, 2009, sell offer EFORds in RPM Auctions could not exceed the EFORd based on 12 months of outage data for the time period ending September 30 prior to the auction. Effective March 27, 2009, sell offer EFORds cannot exceed the greater of of the EFORd based on 12 months of outage data ending September 30 prior to the auction or the EFORd based on five years of outage data ending on September 30 prior to the auction.[40] The result of the rule change was to increase the EFORds used and to decrease the amount of UCAP offered in the auctions. The total internal RTO unforced capacity would have been 186,568.1 MW compared to the actual 184,678.2 MW, a difference of 1,889.9 MW.

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40 126 FERC ¶ 61,275 (2009).

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. As shown in Table 9, the EFORd effect, determined by comparing the actual sell offer EFORd levels applied to the ICAP in the 2012/2013 BRA and 2013/2014 BRA, was -589.3 MW. The net capacity increase from the 2012/2013 BRA to the 2013/2014 BRA was 1,476.9 MW, holding the sell offer EFORds constant at the 2012/2013 BRA level. The components included in the calculation of the net internal capacity increase/decrease for the 2013/2014 BRA that are affected by an EFORd rule change are the EFORd effect MW and the ATSI generation MW. If the highest sell offer EFORd participants could have chosen had been the one year EFORd values, the EFORd effect would have been a positive 1,178.3 MW compared to the actual EFORd effect of -589.3 MW, a difference of 1,767.6 MW. If the highest sell offer EFORd participants could have chosen had been the one year EFORd values, the ATSI generation resources would have had a total UCAP of 12,100.7 MW compared to the actual 11,978.4 MW, a difference of 122.3 MW. If the highest sell offer EFORd participants could have chosen had been the one year EFORd values, the net internal capacity increase would have been 16,614.8 MW (net capacity/DR/EE modifications of 1,476.9 MW plus EFORd effect of 1,178.3 MW plus DR and EE effect of 9.1 MW plus ATSI generation of 12,100.7 MW plus ATSI DR of 1,821.0 MW plus ATSI EE of 28.8 MW) compared to the actual net internal capacity increase of 14,724.9 MW, a difference of 1,889.9 MW (1,767.6 MW plus 122.3 MW).

Table 14 shows the auction results if the maximum EFORd which participants could submit had been the one-year EFORd. More UCAP MW would have been offered as a result of lower sell offer EFORds. Pepco would not have had a binding constraint and would have cleared with MAAC. EMAAC would have cleared at $191.25 per MW-day with a total EMAAC clearing quantity of 33,196.2 MW. MAAC would have cleared at $186.71 per MW-day with a total MAAC clearing quantity of 68,190.6 MW. The RTO would have cleared at $23.47 per MW-day compared to the actual clearing price of $27.73 per MW-day. The entire RTO clearing quantity would have remained the same at 152,743.3 MW. The conclusion is that the inclusion of the maximum of the five-year or the one-year EFORd had a significant impact on the market results.

ILR and the Short-Term Resource Procurement Target

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. The stated rationale is that this provides for short lead time resource procurement in incremental auctions for the given delivery year. For the 2013/2014 BRA, the 2.5 percent reduction resulted in the removal of 3,749.7 MW from the RTO demand curve. For comparison purposes, in the 2011/2012 BRA, removal of the ILR forecast from the reliability requirement resulted in a reduction in demand of 1,593.8 MW, or 1.2 percent of the reliability requirement of 130,658.7 MW.

Table 15 shows the results if the reliability requirements had not been reduced by the 2.5 percent Short-Term Resource Procurement Target and everything else had remained the same. The Pepco LDA would not have been constrained, but would have cleared with MAAC and the clearing quantity would have increased to 5,288.9 MW. The EMAAC clearing price would have increased to $324.01 per MW-day and the clearing quantity would have increased to 32,977.5 MW. The MAAC clearing price would have increased to $272.34 per MW-day and the clearing quantity would have increased to 68,308.1 MW. The RTO clearing price would have increased to $42.00 per MW-day and the clearing quantity would have increased to 156,493.0 MW.

The conclusion is that the removal of 2.5 percent of demand significantly reduced the clearing prices and quantities for Pepco, EMAAC, MAAC and the RTO.

Based on actual auction clearing prices and quantities and make-whole MW, total RPM market revenues for the 2013/2014 delivery year were $6,708,567,045. If the demand curves had not been reduced by the Short-Term Resource Procurement Targets, total RPM market revenues for the 2013/2014 delivery year would have been $8,763,920,530, a difference of $2,055,353,485 compared to the total based on actual results.

The MMU recommends that the use of the 2.5 percent demand adjustment be terminated immediately. 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. 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. In the 2013/2014 BRA, the result was to reduce prices in the eastern part of PJM and to reduce the quantity of capacity purchased in the eastern part of PJM. The result was also to significantly reduce the clearing price for the RTO market, affecting substantial MW of capacity and reducing total payments to capacity by a significant amount.

Impact of Default ACR Calculation

PJM calculated the default ACR values for the first time for the 2013/2014 BRA. As a result of not recalculating the base year values for 2012/2013 using the most recent actual Handy-Whitman Index data, the PJM calculations overstated the default ACR rates by about nine percent. The MMU determined the impact of incorporating PJM's approach to calculating the default ACR values on the outcome of the 2013/2014 BRA. As shown in Table 16, if offer caps had been calculated based on the MMU calculated default ACR rates, the binding constraints and constrained LDA clearing prices and quantities would have remained the same, while the RTO clearing price would have been $24.60 per MW-day compared to the actual clearing price of $27.73 per MW-day. The total RTO clearing quantity would have remained the same at 152,743.3 MW.

Based on actual auction clearing prices and quantities and make-whole MW, total RPM market revenues for the 2013/2014 delivery year were $6,708,567,045. If the MMU calculated default ACR values had been used, total RPM market revenues for the 2013/2014 delivery year would have been $6,573,377,825, a difference of $135,189,220 compared to the total based on actual results.

Tables and Figures for RTO Section

Supply Curves

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 MMU has taken this step in light of the issues related to the release of RPM data.[41] While it is the MMU's view that the supply curves published in prior MMU RPM reports did not reveal confidential data, the MMU has provided only smoothed curves in this report in order to eliminate any controversy associated with the data release issue.

It should be noted that 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.

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[41] *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.

Table 7 RTO offer statistics: 2013/2014 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Total internal RTO capacity (gen, DR, and EE)	195,633.4	184,678.2		
FRR	(25,793.1)	(24,096.4)		
Imports	4,766.1	4,348.2		
RPM capacity	174,606.4	164,930.0		
Exports	(2,624.5)	(2,438.4)		
FRR optional	(1,193.6)	(945.2)		
Excused generation	(9.5)	(4.5)		
Excused DR and EE	(622.6)	(643.8)		
Available	170,156.2	160,898.1	100.0%	100.0%
Generation offered	156,894.1	147,188.6	92.2%	91.4%
DR offered	12,528.7	12,952.7	7.4%	8.1%
EE offered	733.4	756.8	0.4%	0.5%
Total offered	170,156.2	160,898.1	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO	152,227.4	144,067.1	89.5%	89.5%
Cleared in LDAs	9,261.1	8,676.2	5.4%	5.4%
Total cleared	161,488.5	152,743.3	94.9%	94.9%
Make-whole	15.1	14.0	0.0%	0.0%
Uncleared in RTO	7,872.0	7,456.7	4.6%	4.7%
Uncleared in LDAs	780.6	684.1	0.5%	0.4%
Total uncleared	8,652.6	8,140.8	5.1%	5.1%
Reliability requirement		149,988.7		
Total cleared plus make-whole		152,757.3		
Short-Term Resource Procurement Target		3,749.7		
Net excess/(deficit)		6,518.3		
Resource clearing price ($ per MW-day)		$27.73	A	
Preliminary zonal capacity price ($ per MW-day)		$27.73	B	
Base zonal CTR credit rate ($ per MW-day)		$0.00	C	
Preliminary net load price ($ per MW-day)		$27.73	B-C	

Table 8 Capacity modifications (ICAP): 2013/2014 RPM Base Residual Auction[42, 43]

	ICAP (MW)			
	RTO	MAAC	EMAAC	Pepco
Generation increases	897.1	296.5	196.6	18.2
Generation decreases	(1,608.9)	(1,310.9)	(1,148.7)	(27.0)
Capacity modifications net increase/(decrease)	(711.8)	(1,014.4)	(952.1)	(8.8)
DR increases	6,787.3	3,375.9	1,725.2	377.8
DR decreases	(4,957.7)	(2,506.9)	(1,059.1)	(318.0)
DR modifications increase/(decrease)	1,829.6	869.0	666.1	59.8
EE increases	253.9	54.6	14.7	17.5
EE decreases	(155.8)	(87.9)	(14.7)	(37.6)
EE modifications increase/(decrease)	98.1	(33.3)	0.0	(20.1)
Net capacity/DR/EE modifications increase/(decrease)	1,215.9	(178.7)	(286.0)	30.9
ATSI generation	12,837.0			
ATSI DR	1,761.3			
ATSI EE	28.0			
Net Internal Capacity Increase/(Decrease)	15,842.2	(178.7)	(286.0)	30.9

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

43 The total internal MAAC capacity for the 2012/2013 BRA was 72,720.2 MW ICAP and 69,016.9 MW UCAP. These values differ from the values of 72,707.2 MW ICAP and 69,003.9 MW UCAP reported in the "Analysis of the 2012/2013 RPM Base Residual Auction" (August 6, 2009) due to a correction in the modeling of a resource.

Table 9 Capacity modifications (UCAP): 2013/2014 Base Residual Auction

	UCAP (MW)			
	RTO	MAAC	EMAAC	Pepco
Generation increases	866.2	282.5	186.0	16.2
Generation decreases	(1,384.2)	(1,117.7)	(960.6)	(25.4)
Capacity modifications net increase/(decrease)	(518.0)	(835.2)	(774.6)	(9.2)
DR increases	7,014.6	3,489.4	1,783.3	390.4
DR decreases	(5,120.5)	(2,589.2)	(1,093.8)	(328.6)
DR modifications increase/(decrease)	1,894.1	900.2	689.5	61.8
EE increases	261.3	55.6	14.7	18.1
EE decreases	(160.5)	(90.5)	(15.0)	(38.8)
EE modifications increase/(decrease)	100.8	(34.9)	(0.3)	(20.7)
Net capacity/DR/EE modifications increase/(decrease)	1,476.9	30.1	(85.4)	31.9
EFORd effect	(589.3)	27.7	117.5	(159.4)
DR and EE effect	9.1	4.2	1.0	0.4
ATSI generation	11,978.4			
ATSI DR	1,821.0			
ATSI EE	28.8			
Net Internal Capacity Increase/(Decrease)	14,724.9	62.0	33.1	(127.1)

Table 10 Cleared MW by zone and resource type/fuel source: 2013/2014 Base Residual Auction[44]

	Cleared UCAP (MW)										
Zone	DR	EE	Coal	Gas	Hydroelectric	Nuclear	Oil	Solar	Solid Waste	Wind	Total
AECO	122.1	3.1	791.1	590.5	0.0	0.0	379.4	1.5	0.0	0.0	1,887.7
AEP	823.9	3.8	1,909.7	4,682.3	103.5	309.4	0.0	0.0	0.0	147.8	7,980.4
APS	523.2	2.5	7,236.4	1,818.1	78.6	0.0	0.0	0.0	0.0	76.0	9,734.8
ATSI	394.3	3.0	6,637.1	1,596.8	31.2	1,943.4	121.3	0.0	0.0	0.0	10,727.1
BGE	1,102.5	74.8	1,983.3	967.0	0.0	1,708.8	560.0	0.0	54.0	0.0	6,450.4
ComEd	851.9	511.8	6,002.4	8,064.3	0.0	9,868.6	123.4	0.0	0.0	266.2	25,688.6
DAY	42.5	1.1	1,113.2	936.3	0.0	0.0	46.6	0.0	0.0	0.0	2,139.7
DLCO	142.3	0.5	639.4	219.6	0.0	1,732.2	39.6	0.0	0.0	0.0	2,773.6
Dominion	632.7	4.7	5,815.9	7,488.2	3,487.8	3,632.1	1,612.4	0.0	162.6	0.0	22,836.4
DPL	245.7	3.4	819.4	2,155.9	0.0	0.0	1,238.8	0.0	0.0	0.0	4,463.2
EXT	0.0	0.0	2,562.8	455.0	205.0	0.0	0.0	0.0	0.0	0.0	3,222.8
JCPL	283.7	4.4	0.0	2,262.6	397.2	557.1	562.0	0.0	9.3	0.0	4,076.3
Met-Ed	318.1	7.2	713.0	1,934.3	17.5	802.5	372.4	0.0	77.5	0.0	4,242.5
PECO	658.2	5.6	0.0	2,571.9	1,632.3	4,477.3	1,454.6	1.1	104.0	0.0	10,905.0
PENELEC	420.7	8.0	6,363.9	300.7	483.9	0.0	27.1	0.0	40.4	77.0	7,721.7
Pepco	547.3	35.8	2,065.8	781.7	0.0	0.0	1,311.1	0.0	50.0	0.0	4,791.7
PPL	1,021.2	2.3	3,535.6	3,685.2	562.4	2,437.6	300.6	0.0	30.7	22.6	11,598.2
PSEG	1,119.2	7.4	1,081.6	5,237.3	1.8	3,420.7	460.8	8.0	134.0	0.0	11,470.8
RECO	32.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	32.4
Total	9,281.9	679.4	49,270.6	45,747.7	7,001.2	30,889.7	8,610.1	10.6	662.5	589.6	152,743.3

Table 11 Uncleared generation offers by technology type and age: 2013/2014 RPM Base Residual Auction

	Uncleared UCAP (MW)	
Technology Type	Less Than or Equal to 40 Years Old	Greater than 40 Years Old
Combined cycle	643.5	0.0
Combustion turbine	719.2	19.2
Oil or gas dteam	29.9	168.3
Subcritical/Supercritical Coal	545.3	2,255.7
Other	11.5	0.0
Total	1,949.4	2,443.2

[44] 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, 3,451.7 MW of the 11,470.8 cleared MW in the PSEG zone were modeled and cleared in the EMAAC LDA.

Table 12 Uncleared generation resources in multiple auctions

Technology	2013/2014 Uncleared UCAP (MW)	2013/2014 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	2011/2012 Results for Same Set of Resources Uncleared UCAP (MW)	2011/2012 Results for Same Set of Resources Number of Resources
Combined cycle	643.5	5	0.0	0	0.0	0
Combustion turbine	738.4	20	593.5	14	0.3	1
Subcritical/supercritical coal	2,801.0	25	245.4	6	58.6	3
Oil or gas steam	198.2	3	156.8	2	0.0	0
Other	11.5	1	11.5	1	0.0	0
Total	4,392.6	54	1,007.2	23	58.9	4

Table 13 Offers greater than $35.00 on total RTO supply curve: 2013/2014 RPM Base Residual Auction

Technology/Resource Type	UCAP (MW)	Percent of Offers
DR	5,599.9	38.4%
Subcritical coal	3,088.8	21.2%
Oil or gas steam	2,877.7	19.8%
Supercritical coal	1,682.2	11.6%
Combustion turbine	1,069.5	7.3%
EE	102.5	0.7%
Combined cycle	98.5	0.7%
Other	43.4	0.3%
Total	14,562.5	100.0%

Table 14 Impact of EFORd-5: 2013/2014 RPM Base Residual Auction

LDA	Actual Auction Results Clearing Prices ($ per MW-day)	Actual Auction Results Cleared UCAP (MW)	Without EFORd-5 Option Clearing Prices ($ per MW-day)	Without EFORd-5 Option Cleared UCAP (MW)
Pepco	$247.14	4,791.7	$186.71	4,950.0
EMAAC	$245.00	32,835.4	$191.25	33,196.2
MAAC	$226.15	67,639.9	$186.71	68,190.6
RTO	$27.73	152,743.3	$23.47	152,743.3

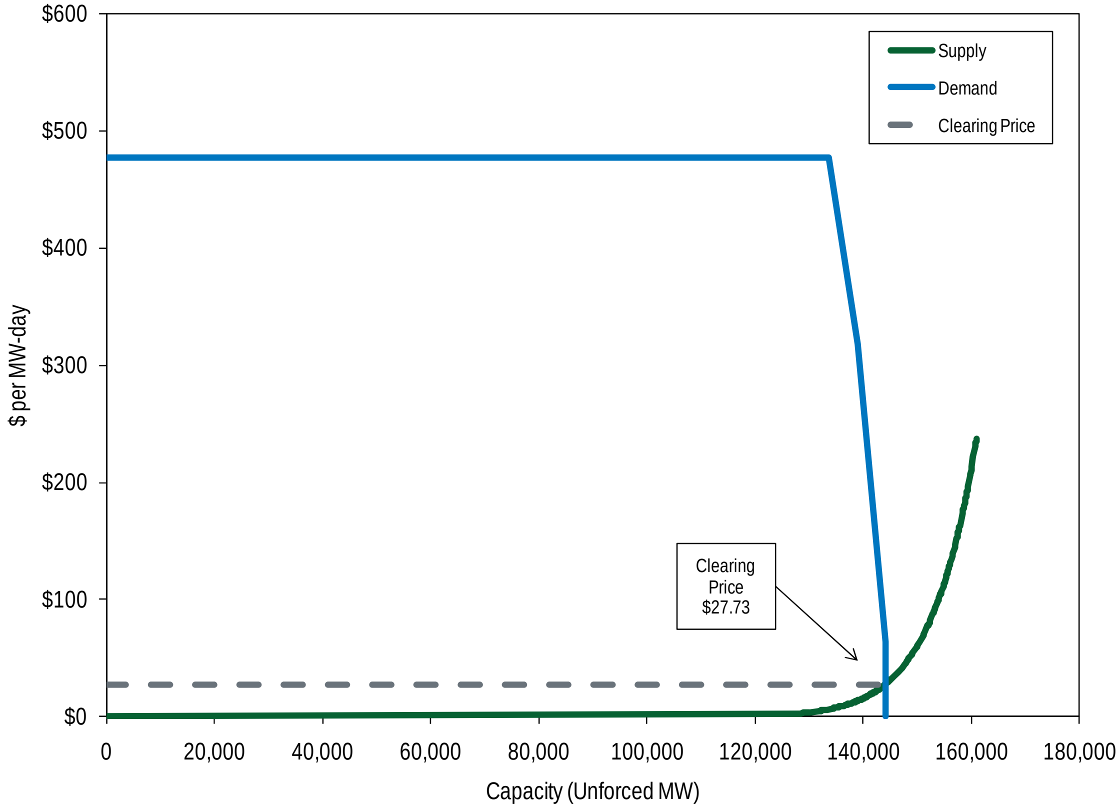
Table 15 Impact of not reducing demand by Short-Term Resource Procurement Target: 2013/2014 RPM Base Residual Auction

LDA	Actual Auction Results Clearing Prices ($ per MW-day)	Actual Auction Results Cleared UCAP (MW)	Without Short-Term Resource Procurement Target Reduction Clearing Prices ($ per MW-day)	Without Short-Term Resource Procurement Target Reduction Cleared UCAP (MW)
Pepco	$247.14	4,791.7	$272.34	5,288.9
EMAAC	$245.00	32,835.4	$324.01	32,977.5
MAAC	$226.15	67,639.9	$272.34	68,308.1
RTO	$27.73	152,743.3	$42.00	156,493.0

Table 16 Impact of default ACR calculation: 2013/2014 RPM Base Residual Auction

LDA	Actual Auction Results Clearing Prices ($ per MW-day)	Actual Auction Results Cleared UCAP (MW)	With MMU Calculated Default ACR Values Clearing Prices ($ per MW-day)	With MMU Calculated Default ACR Values Cleared UCAP (MW)
Pepco	$247.14	4,791.7	$247.14	4,791.7
EMAAC	$245.00	32,835.4	$245.00	32,835.4
MAAC	$226.15	67,639.9	$226.15	67,639.9
RTO	$27.73	152,743.3	$24.60	152,743.3

Figure 1 RTO market supply/demand curves: 2013/2014 RPM Base Residual Auction[45]



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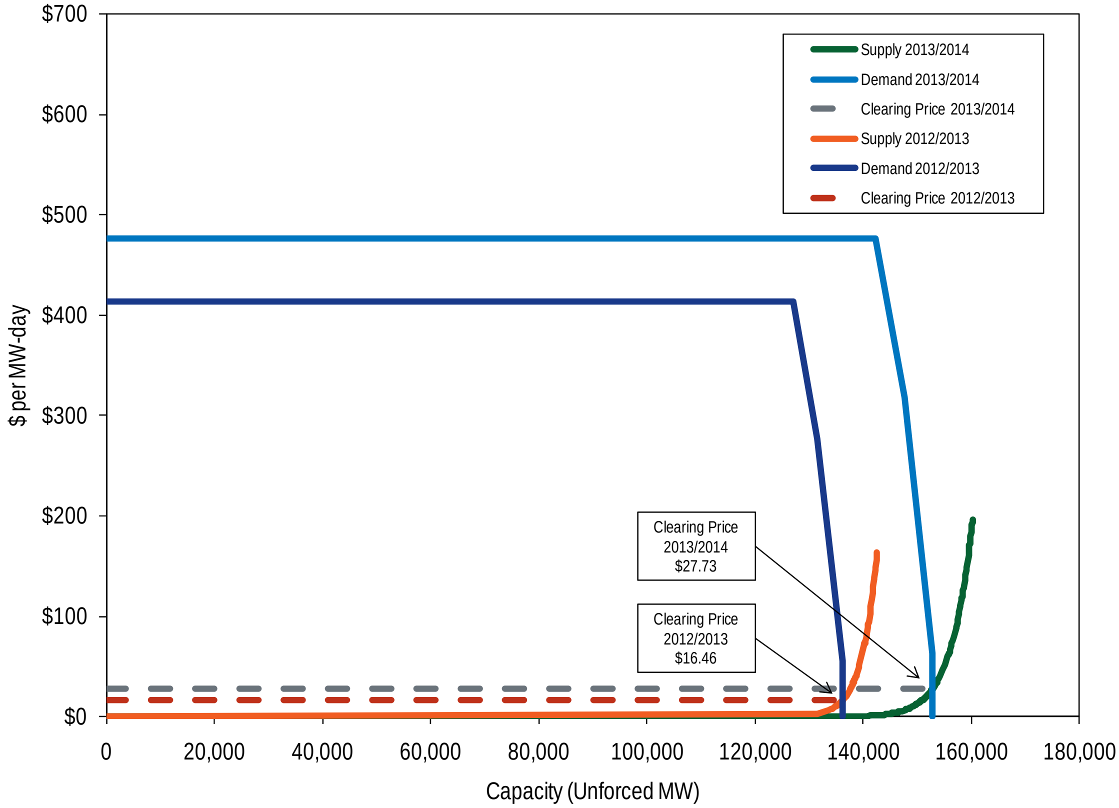
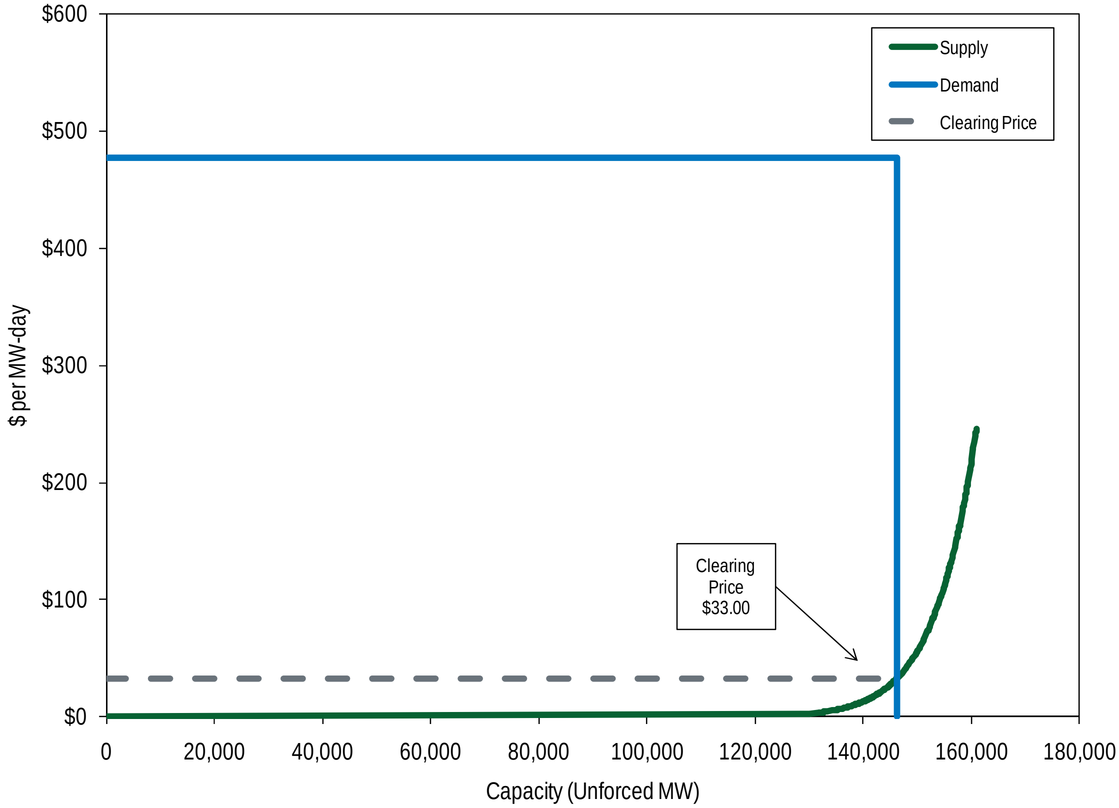
[45] The supply curves presented in this report have all been smoothed using a statistical technique that fits a smooth curve to the underlying supply curve data while ensuring that the point of intersection between supply and demand curves is at the market clearing price. The supply curve includes all offered MW while the prices on the supply curve reflect the smoothing method. The demand curve excludes incremental demand which cleared in MAAC, EMAAC, and Pepco.

Figure 2 RTO market supply/demand curves: 2012/2013 and 2013/2014 RPM Base Residual Auctions[46]



[46] 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 curves include offered MW in the rest of RTO shifted to the right by the amount cleared in the LDAs while the prices on the supply curve reflect the smoothing method. The demand curves are represented by the original VRR points.

Figure 3 PJM as a single market supply/demand curves at reliability requirement: 2013/2014 RPM Base Residual Auction[47]



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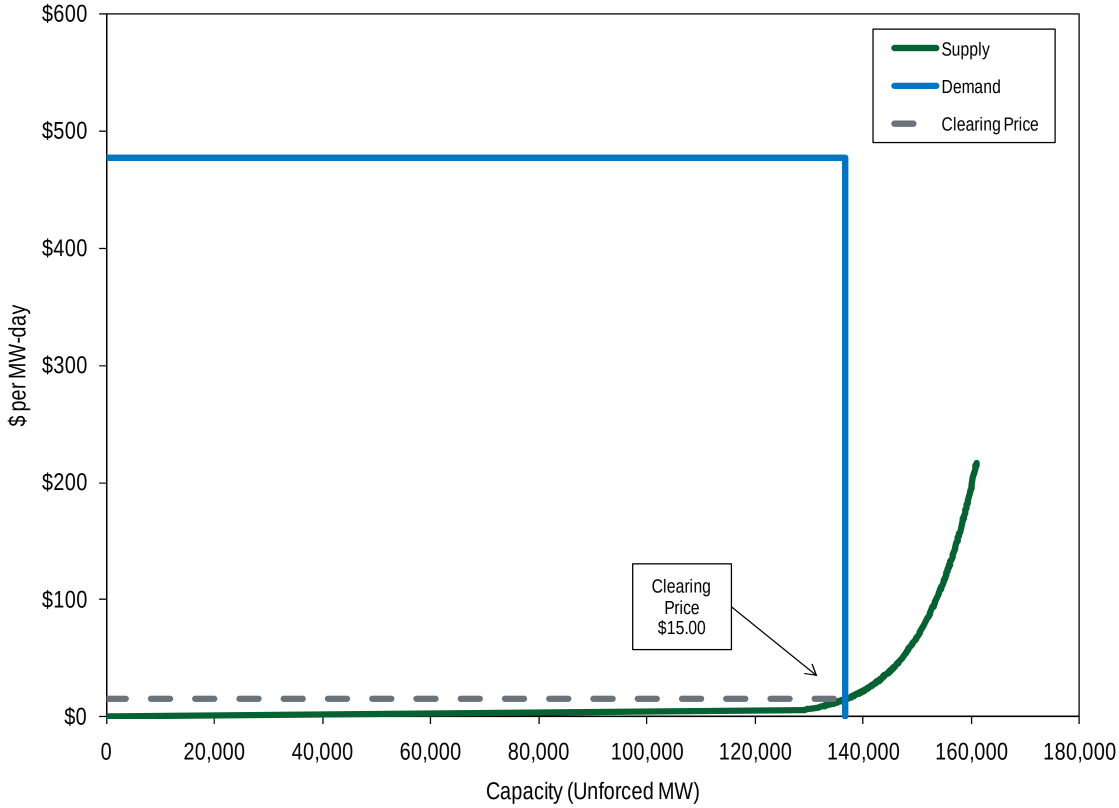
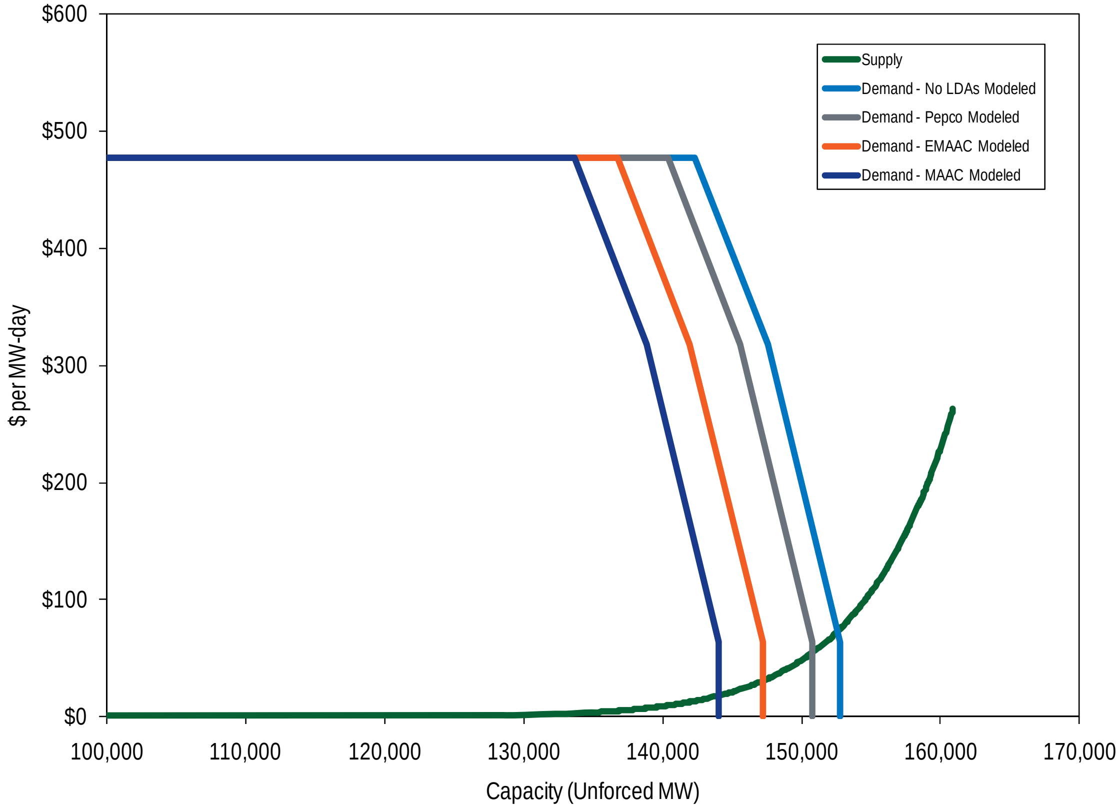
[47] The supply curves presented in this report have all been smoothed using a statistical technique that fits a smooth curve to the underlying supply curve data while ensuring that the point of intersection between supply and demand curves is at the market clearing price. The supply curve includes all offered MW while the prices on the supply curve reflect the smoothing method. The demand curve is the RTO reliability requirement less the Short-Term Resource Procurement Target, set at 2.5 percent.

Figure 4 RTO supply/demand curves at reliability requirement: 2013/2014 RPM Base Residual Auction[48]



48 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 demand curve is the RTO reliability requirement less the Short-Term Resource Procurement Target, set at 2.5 percent, and excludes incremental demand that would clear in MAAC, EMAAC, and Pepco if the LDAs were cleared at the LDA reliability requirements.

Figure 5 RTO market supply/demand curves: Impact of constraints on price formation: 2013/2014 RPM Base Residual Auction[49, 50]



MAAC

Table 17 shows total MAAC offer data for the 2013/2014 RPM Base Residual Auction. All MW values stated in the MAAC section include all nested LDAs. Total internal MAAC unforced capacity of 69,078.9 MW includes all generating units, demand resources, and energy efficiency resources that qualified as a PJM capacity resource, excluding external units, and also includes owners' modifications to ICAP ratings. As shown in Table 9, MAAC unforced internal capacity increased 62.0 MW from 69,016.9 MW in the 2012/2013 BRA as a result of net generation capacity modifications (-835.2 MW), net DR

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49 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.

50 For ease of viewing, the graph is truncated at less than 100,000 MW.

modifications (900.2 MW), and net EE modifications (-34.9 MW).[51] An increase of 27.7 MW was due to lower sell offer EFORds, and the remaining increase of 4.2 MW was due to a higher Load Management UCAP conversion factor compared to the 2012/2013 BRA.

All imports offered into the auction are modeled in the RTO, so total MAAC RPM capacity was the same as the internal capacity of 69,078.9 MW.[52] For each LDA, the capacity includes the capacity in the LDA and all nested LDAs. Exports were 674.0 MW, 4.5 MW were excused from the RPM must-offer requirement as a result of performance concerns (2.5 MW) and other factors (2.0 MW), and 62.4 MW of DR and EE were not offered, resulting in available unforced capacity of 68,338.0 MW. After accounting for the above exceptions, all capacity resources in MAAC were offered into the RPM auction.

Of the 67,639.9 MW cleared in MAAC, 58,963.7 MW were cleared in the RTO before MAAC became constrained. Once the constraint was binding, based on the 4,460.0 MW CETL value, only the incremental supply located in MAAC was available to meet the incremental demand in the LDA. Of the 9,374.3 MW of incremental supply, 8,676.2 MW cleared, which resulted in a clearing price of $226.15 per MW-day, as shown in Figure 6. The price was determined by the intersection of the incremental supply and demand curves. The market results in the 2013/2014 BRA included a make-whole quantity of 14.0 MW in EMAAC. The 684.1 MW that did not clear resulted from offer prices which exceeded the clearing price. Of the uncleared MW in MAAC, all 684.1 MW were generation offers. See Table 11 for more details.

If the demand curve had been vertical at the reliability requirement less the Short-Term Resource Procurement Target with the same maximum price set at 1.5 times net CONE and given the same LDA modeling, the MAAC clearing price would have been $170.71 per MW-day, as shown in Figure 7, compared to the actual clearing price of $226.15 per MW-day.

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[51] The total internal MAAC capacity for the 2012/2013 BRA was 72,720.2 MW ICAP and 69,016.9 MW UCAP. These values differ from the values of 72,707.2 MW ICAP and 69,003.9 MW UCAP reported in the "Analysis of the 2012/2013 RPM Base Residual Auction" (August 6, 2009) due to a correction in the modeling of a resource.

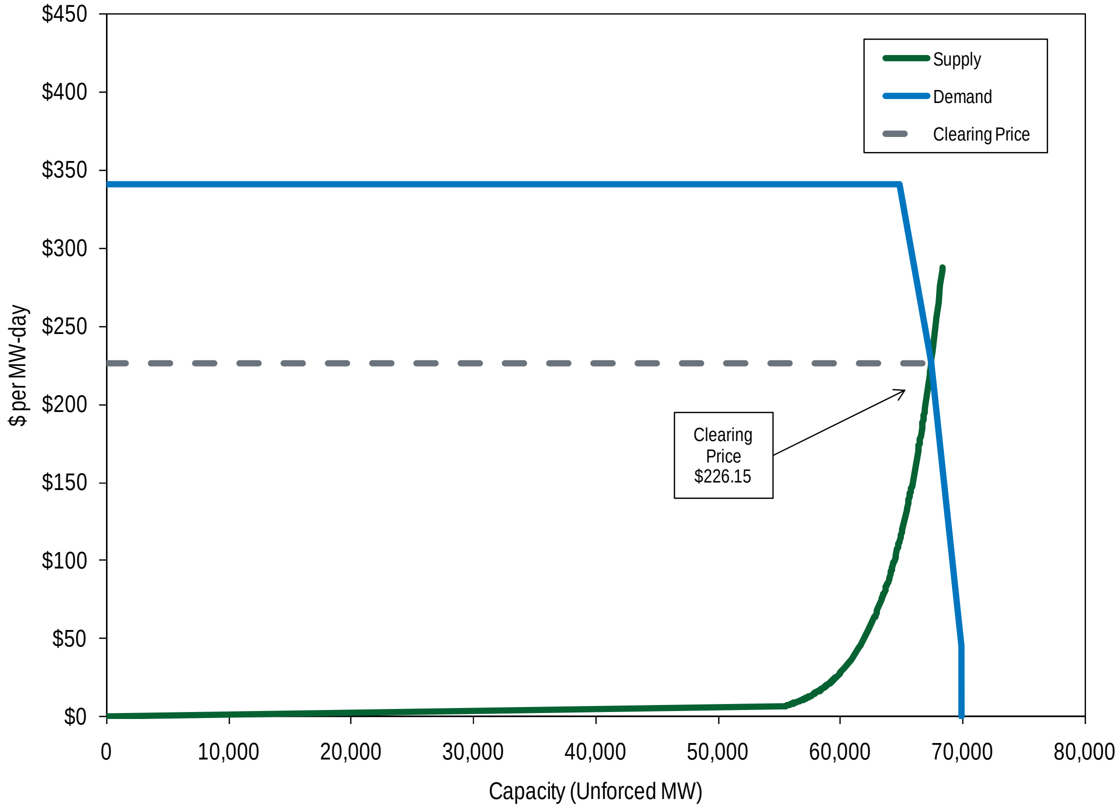
[52] See PJM. "Manual 18: PJM Capacity Market," Revision 10 (Effective June 1, 2010), p. 24, < http://www.pjm.com/~/media/documents/manuals/m18.ashx> (1.31 MB).

Table and Figures for MAAC Section

Table 17 MAAC offer statistics: 2013/2014 RPM Base Residual Auction

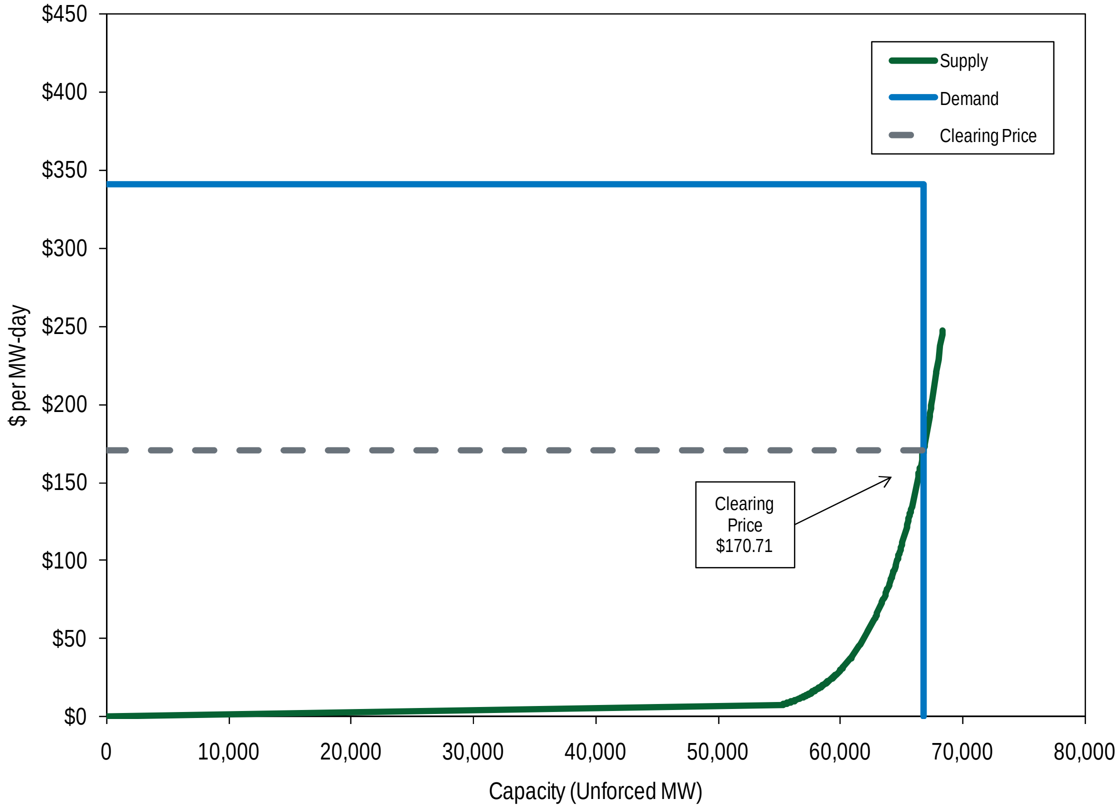
	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Total internal MAAC capacity (gen, DR, and EE)	72,541.5	69,078.9		
Imports	0.0	0.0		
RPM capacity	72,541.5	69,078.9		
Exports	(674.0)	(674.0)		
Excused generation	(9.5)	(4.5)		
Excused DR and EE	(60.3)	(62.4)		
Available	71,797.7	68,338.0	100.0%	100.0%
Generation offered	65,971.1	62,314.9	91.9%	91.2%
DR offered	5,678.7	5,871.1	7.9%	8.6%
EE offered	147.9	152.0	0.2%	0.2%
Total offered	71,797.7	68,338.0	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO	61,740.9	58,963.7	86.0%	86.3%
Cleared in MAAC	9,016.6	8,454.2	12.6%	12.4%
Cleared in EMAAC	103.9	90.9	0.1%	0.1%
Cleared in Pepco	140.6	131.1	0.2%	0.2%
Total cleared	71,002.0	67,639.9	98.9%	99.0%
Make-whole	15.1	14.0	0.0%	0.0%
Uncleared	780.6	684.1	1.1%	1.0%
Reliability requirement		73,142.0		
Total cleared plus make-whole		67,653.9		
CETL		4,460.0		
Total Resources		72,113.9		
Short-Term Resource Procurement Target		1,691.0		
Net excess/(deficit)		662.9		
Resource clearing price ($ per MW-day)		$226.15	A	
Preliminary zonal capacity price ($ per MW-day)		$226.15	B	
Base zonal CTR credit rate ($ per MW-day)		$2.30	C	
Preliminary net load price ($ per MW-day)		$223.85	B-C	

Figure 6 MAAC market supply/demand curves: 2013/2014 RPM Base Residual Auction[53]



53 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 demand curve is reduced by the CETL and incremental demand which cleared in EMAAC and Pepco.

Figure 7 MAAC market supply/demand curves at the reliability requirement: 2013/2014 RPM Base Residual Auction[54]



EMAAC

Table 18 shows total EMAAC offer data for the 2013/2014 RPM Base Residual Auction. All MW values stated in the EMAAC section include all nested LDAs. Total internal EMAAC unforced capacity of 33,700.6 MW includes all generating units, demand resources, and energy efficiency resources that qualified as a PJM capacity resource and also includes owners' modifications to ICAP ratings. As shown in Table 9, EMAAC unforced internal capacity increased 33.1 MW from 33,667.5 MW in the 2012/2013 BRA as a result of net generation capacity modifications (-774.6 MW), net DR modifications

[54] 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 demand curve is the MAAC reliability requirement less the Short-Term Resource Procurement Target, the CETL, and incremental demand that would clear in EMAAC and Pepco if the LDAs were cleared at the LDA reliability requirements.

(689.5 MW), and net EE modifications (-0.3 MW). An increase of 117.5 MW was due to lower sell offer EFORds, and the remaining increase of 1.0 MW was due to a higher Load Management UCAP conversion factor compared to the 2012/2013 BRA. All imports offered into the auction are modeled in the RTO, so total EMAAC RPM capacity was the same as the internal capacity of 33,700.6 MW. Exports were 674.0 MW, 2.5 MW were excused from the RPM must-offer requirement as a result of performance concerns (2.5 MW), and 16.7 MW DR and EE were not offered, resulting in available unforced capacity of 33,007.4 MW. All capacity resources in EMAAC were offered into the RPM auction.

Of the 32,835.4 MW cleared in EMAAC, 29,144.9 MW were cleared in the RTO and an additional 3,599.6 MW cleared in MAAC before EMAAC became constrained. Once the constraint was binding, based on the 7,095.0 MW CETL value, only the incremental supply located in EMAAC was available to meet the incremental demand in the LDA. Of the 262.9 MW of incremental supply, 90.9 MW cleared, which resulted in a resource clearing price of $245.00 per MW-day, as shown in Figure 8. The price was determined by the intersection of the incremental supply and demand curves. The market results in the 2013/2014 BRA included a make-whole quantity of 14.0 MW in EMAAC. The 158.0 MW of uncleared capacity resulted from offer prices which exceeded the clearing price. Of the uncleared MW in EMAAC, all 158.0 MW were generation offers. See Table 11 for more details.

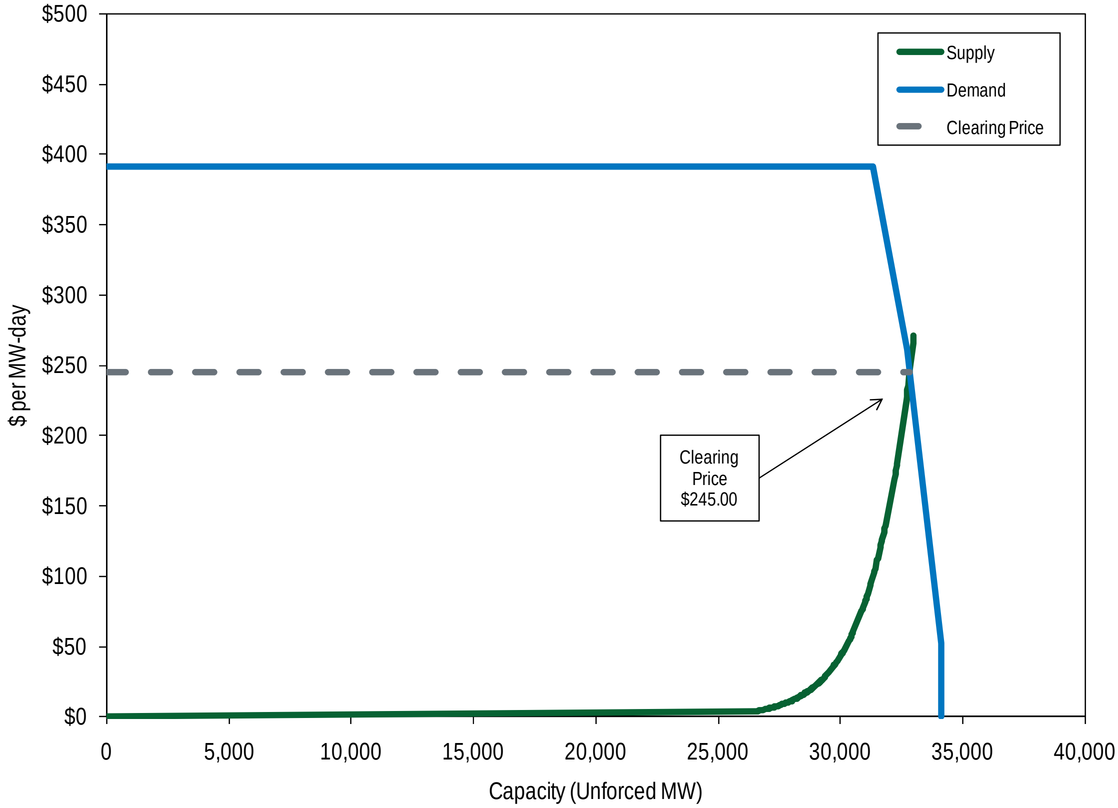
If the demand curve had been vertical at the reliability requirement less the Short-Term Resource Procurement Target with the same maximum price set at 1.5 times net CONE and given the same LDA modeling, the EMAAC clearing price would have been $191.25 per MW-day, as shown in Figure 9, compared to the actual clearing price of $245.00 per MW-day.

Table and Figures for EMAAC Section

Table 18 EMAAC offer statistics: 2013/2014 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Total internal EMAAC capacity (gen, DR, and EE)	35,193.9	33,700.6		
Imports	0.0	0.0		
RPM capacity	35,193.9	33,700.6		
Exports	(674.0)	(674.0)		
Excused generation	(6.3)	(2.5)		
Excused DR and EE	(16.2)	(16.7)		
Available	34,497.4	33,007.4	100.0%	100.0%
Generation offered	32,092.9	30,522.2	93.0%	92.4%
DR offered	2,380.7	2,461.3	6.9%	7.5%
EE offered	23.8	23.9	0.1%	0.1%
Total offered	34,497.4	33,007.4	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO	30,401.9	29,144.9	88.1%	88.3%
Cleared in MAAC	3,780.5	3,599.6	11.0%	10.9%
Cleared in EMAAC	103.9	90.9	0.3%	0.3%
Total cleared	34,286.3	32,835.4	99.4%	99.5%
Make-whole	15.1	14.0	0.0%	0.0%
Uncleared	196.0	158.0	0.6%	0.5%
Reliability requirement		40,398.0		
Total cleared plus make-whole		32,849.4		
CETL		7,095.0		
Total Resources		39,944.4		
Short-Term Resource Procurement Target		925.7		
Net excess/(deficit)		472.1		
Resource clearing price ($ per MW-day)		$245.00	A	
Preliminary zonal capacity price ($ per MW-day)		$245.09	B	
Base zonal CTR credit rate ($ per MW-day)		$4.68	C	
Preliminary net load price ($ per MW-day)		$240.41	B-C	

Figure 8 EMAAC market supply/demand curves: 2013/2014 RPM Base Residual Auction[55]



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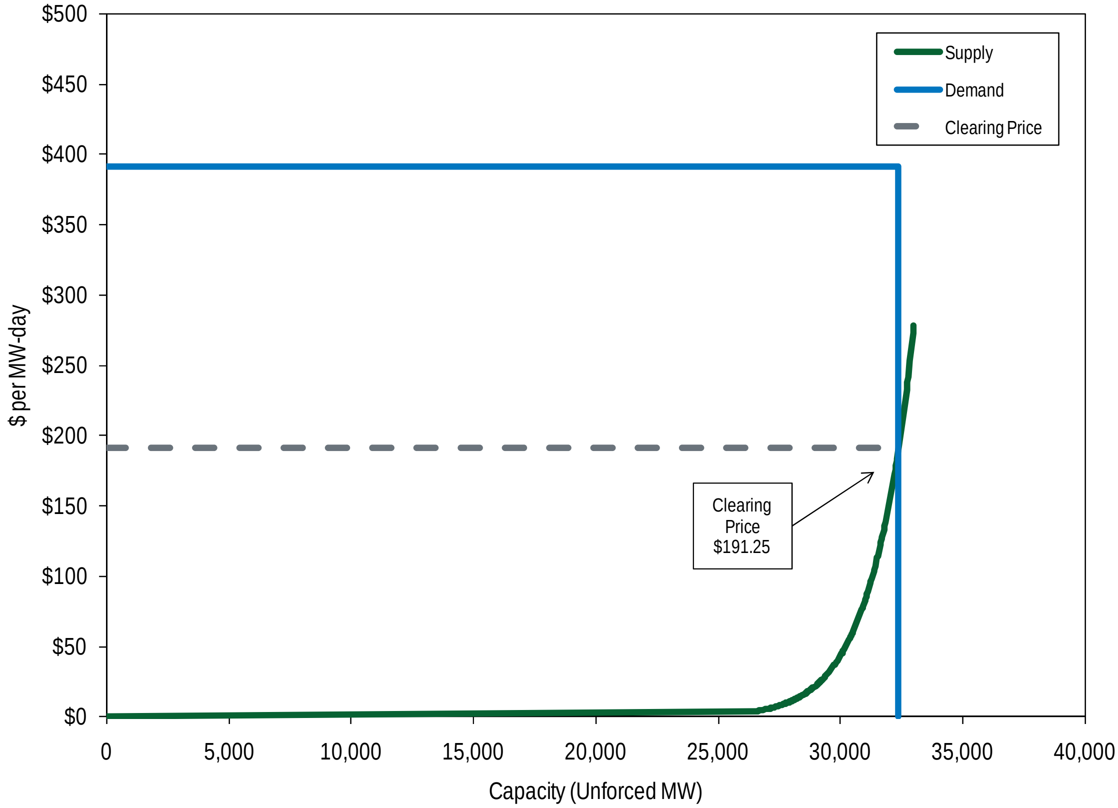
[55] The supply curves presented in this report have all been smoothed using a statistical technique that fits a smooth curve to the underlying supply curve data while ensuring that the point of intersection between supply and demand curves is at the market clearing price. The supply curve includes all offered MW while the prices on the supply curve reflect the smoothing method. The demand curve is reduced by the CETL.

Figure 9 EMAAC market supply/demand curves at the reliability requirement: 2013/2014 RPM Base Residual Auction[56]



Pepco

Table 19 shows total Pepco offer data for the 2013/2014 RPM Base Residual Auction. Total internal Pepco unforced capacity of 5,288.9 MW includes all generating units, demand resources, and energy efficiency resources that qualified as a PJM capacity resource, excluding external units, and also includes owners' modifications to ICAP ratings. As shown in Table 9, Pepco unforced internal capacity decreased 127.1 MW from 5,416.0 MW in the 2012/2013 BRA as a result of net generation capacity modifications (-9.2 MW), net DR modifications (61.8 MW), and net EE modifications (-20.7 MW). A decrease of 159.4 MW was due to higher sell offer EFORds, and the

56 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 demand curve is the EMAAC reliability requirement less the Short-Term Resource Procurement Target and the CETL.

remaining increase of 0.4 MW was due to a higher Load Management UCAP conversion factor compared to the 2012/2013 BRA.

All imports offered into the auction are modeled in the RTO, so RPM capacity was 5,288.9 MW. There were no exports from or excused MW in Pepco, so the total available capacity in Pepco was the same as the internal capacity of 5,288.9 MW. All capacity resources in Pepco were offered into the RPM auction.

Of the 4,791.7 MW cleared in Pepco, 2,366.5 MW were cleared in the RTO and 2,294.1 MW cleared in MAAC before Pepco became constrained. Once the constraint was binding, based on the 4,483.0 MW CETL value, only the incremental supply located in Pepco was available to meet the incremental demand in the LDA. Of the 628.3 MW of incremental supply, 131.1 MW cleared, which resulted in a resource clearing price of $247.14 per MW-day, as shown in Figure 10. The price was determined by the intersection of the incremental supply and demand curves. The 497.2 MW of uncleared capacity resulted from offer prices which exceeded the clearing price, all of which were generation offers. See Table 11 for more details.

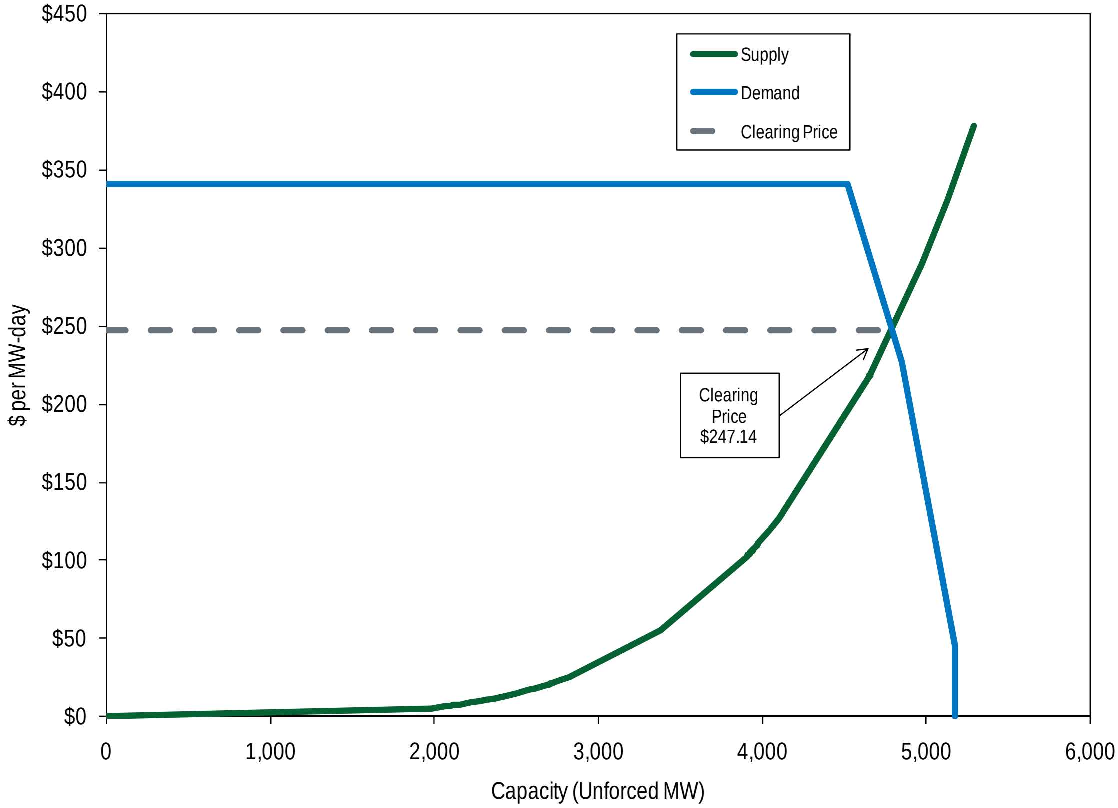
If the demand curve had been vertical at the reliability requirement less the Short-Term Resource Procurement Target with the same maximum price set at 1.5 times net CONE, the clearing price would have been the same at $247.14 per MW-day, as shown in Figure 11.

Table and Figures for Pepco Section

Table 19 Pepco offer statistics: 2013/2014 RPM Base Residual Auction

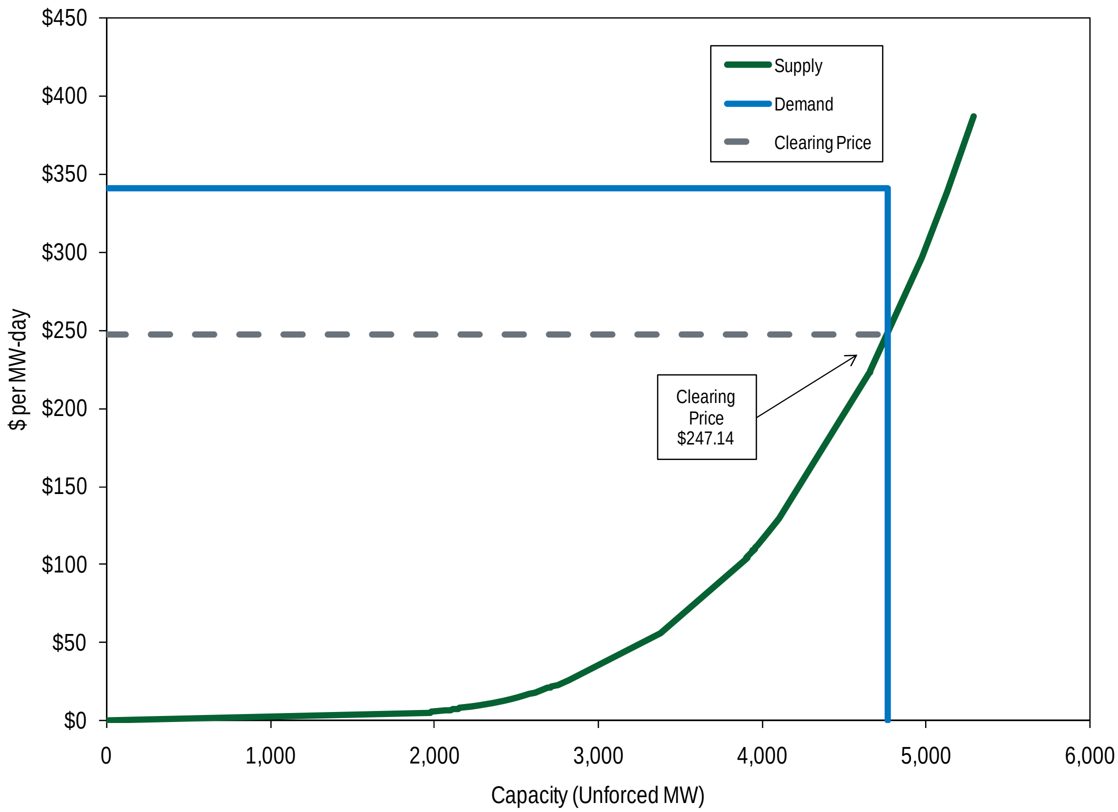
	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Total internal Pepco capacity (gen, DR, and EE)	6,014.5	5,288.9		
Imports	0.0	0.0		
RPM capacity	6,014.5	5,288.9		
Exports	0.0	0.0		
Excused generation	0.0	0.0		
Excused DR and EE	0.0	0.0		
Available	6,014.5	5,288.9	100.0%	100.0%
Generation offered	5,450.3	4,705.8	90.6%	89.0%
DR offered	529.6	547.3	8.8%	10.3%
EE offered	34.6	35.8	0.6%	0.7%
Total offered	6,014.5	5,288.9	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO	2,683.4	2,366.5	44.7%	44.7%
Cleared in MAAC	2,637.1	2,294.1	43.8%	43.4%
Cleared in Pepco	140.6	131.1	2.3%	2.5%
Total cleared	5,461.1	4,791.7	90.8%	90.6%
Make-whole	0.0	0.0	0.0%	0.0%
Uncleared	553.4	497.2	9.2%	9.4%
Reliability requirement		9,442.0		
Total cleared plus make-whole		4,791.7		
CETL		4,483.0		
Total Resources		9,274.7		
Short-Term Resource Procurement Target		191.6		
Net excess/(deficit)		24.3		
Resource clearing price ($ per MW-day)		$247.14	A	
Preliminary zonal capacity price ($ per MW-day)		$247.14	B	
Base zonal CTR credit rate ($ per MW-day)		$10.21	C	
Preliminary net load price ($ per MW-day)		$236.93	B-C	

Figure 10 Pepco market supply/demand curves: 2013/2014 RPM Base Residual Auction[57]



[57] 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 demand curve is reduced by the CETL.

Figure 11 Pepco market supply/demand curves at reliability requirement: 2013/2014 RPM Base Residual Auction[58]



Demand Side

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 into the auction as a capacity resource and receive the resource clearing price.

There are three basic demand side products incorporated in the RPM market design:

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[58] 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 demand curve is the RTO reliability requirement less the Short-Term Resource Procurement Target and the CETL.

- **DR.** Capacity load resource that is offered into an RPM auction as capacity and receives the relevant LDA or RTO resource clearing price; and

- **ILR.** Capacity load resource that is not offered into the RPM auction, but receives the final zonal ILR price determined after the second incremental auction. Beginning in the 2012/2013 delivery year, the load management product ILR was eliminated.

- **EE.** The Energy Efficiency (EE) resource type is eligible to be offered in RPM auctions starting with the 2012/2013 delivery year and also for incremental auctions in the 2011/2012 delivery year.[59] An EE Resource is a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, exceeding then current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak periods) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the delivery year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such delivery year, without any requirement of notice, dispatch, or operator intervention.[60]

As shown in Table 20, DR offers increased from 9,847.6 MW in the 2012/2013 BRA to 12,952.7 MW in the 2013/2014 BRA, an increase of 3,105.1 or 31.5 percent.

Table 21 shows the DR and EE offered MW by price range in the 2013/2014 BRA. DR and EE offers totaled 13,709.5 MW with sell offers ranging from $0 per MW-day to $1,000 per MW-day. DR and EE offers at less than or equal to $20 per MW-day totaled 6,979.8 MW (50.9 percent), and DR and EE offers at less than or equal to $100 per MW-day totaled 12,802.9 MW (93.4 percent).

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 MMU will investigate the acquisition of better data on the marginal cost of providing such resources.

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

60 See "Reliability Assurance Agreement among Load-Serving Entities in the PJM Region," First Revised Sheet No. 35C (Effective March 27, 2009), Section M.

Tables and Figures for Demand Side Section

Table 20 DR and EE statistics by LDA: 2012/2013 and 2013/2014 Base Residual Auctions

		2012/2013 BRA		2013/2014 BRA		Change in UCAP	
LDA		ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)	MW	Percentage
RTO	DR Offered	9,535.4	9,847.6	12,528.7	12,952.7	3,105.1	31.5%
	EE Offered	632.3	652.7	733.4	756.8	104.1	15.9%
	DR Cleared	6,824.1	7,047.2	8,977.4	9,281.9	2,234.7	31.7%
	EE Cleared	551.3	568.9	658.5	679.4	110.5	19.4%
MAAC	DR Offered	4,870.0	5,029.2	5,678.7	5,871.1	841.9	16.7%
	EE Offered	181.2	186.9	147.9	152.0	(34.9)	(18.7%)
	DR Cleared	4,574.2	4,723.7	5,678.7	5,871.1	1,147.4	24.3%
	EE Cleared	174.6	179.9	147.9	152.0	(27.9)	(15.5%)
EMAAC	DR Offered	1,730.8	1,787.3	2,380.7	2,461.3	674.0	37.7%
	EE Offered	23.8	24.4	23.8	23.9	(0.5)	(2.0%)
	DR Cleared	1,586.6	1,638.4	2,380.7	2,461.3	822.9	50.2%
	EE Cleared	19.7	20.0	23.8	23.9	3.9	19.5%
SWMAAC	DR Offered	1,797.0	1,855.7	1,595.8	1,649.8	(205.9)	(11.1%)
	EE Offered	157.2	162.3	107.0	110.6	(51.7)	(31.9%)
	DR Cleared	1,717.7	1,773.7	1,595.8	1,649.8	(123.9)	(7.0%)
	EE Cleared	154.7	159.7	107.0	110.6	(49.1)	(30.7%)
PSEG	DR Offered	457.8	472.9	1,082.6	1,119.2	646.3	136.7%
	EE Offered	4.0	4.1	7.3	7.4	3.3	80.5%
	DR Cleared	445.4	460.1	1,082.6	1,119.2	659.1	143.3%
	EE Cleared	2.9	2.9	7.3	7.4	4.5	155.2%
PSEG North	DR Offered	65.4	67.6	510.1	527.4	459.8	680.2%
	EE Offered	0.9	0.9	0.6	0.6	(0.3)	(33.3%)
	DR Cleared	65.4	67.6	510.1	527.4	459.8	680.2%
	EE Cleared	0.9	0.9	0.6	0.6	(0.3)	(33.3%)
DPL South	DR Offered	62.5	64.6	140.6	145.6	81.0	125.4%
	EE Offered	0.0	0.0	2.0	2.0	2.0	NA
	DR Cleared	62.5	64.6	140.6	145.6	81.0	125.4%
	EE Cleared	0.0	0.0	2.0	2.0	2.0	NA
Pepco	DR Offered	469.8	485.1	529.6	547.3	62.2	12.8%
	EE Offered	54.7	56.5	34.6	35.8	(20.7)	(36.6%)
	DR Cleared	446.3	460.8	529.6	547.3	86.5	18.8%
	EE Cleared	54.7	56.5	34.6	35.8	(20.7)	(36.6%)

Table 21 DR and EE Offers by Price Range: 2013/2014 Base Residual Auction

Price Range	UCAP (MW)	Cumulative Percent
$0 per MW-day to $20 per MW-day	6,979.8	50.9%
$20 per MW-day to $40 per MW-day	1,345.6	60.7%
$40 per MW-day to $60 per MW-day	2,562.3	79.4%
$60 per MW-day to $80 per MW-day	918.9	86.1%
$80 per MW-day to $100 per MW-day	996.3	93.4%
> $100 per MW-day	906.6	100.0%

DR Analysis

Impact of Demand Side Resources

Demand side resources, including both DR and EE, had a significant impact on the outcome of the 2013/2014 BRA. The results of the BRA were analyzed under a range of possible levels of DR and EE participation to illustrate this impact, including no demand side offers, one third of actual demand side offers and two thirds of actual demand side offers.

While competition from demand side resources improves the functioning of the market, such is not the case if the demand side resources are not comparable to other capacity resources. The purpose of the 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 in the Load Management Program 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, there is an expectation that 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 addressed in order to ensure that such resources provide the same value in the capacity market as generation 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. Alternatively, the MW offered could be lower. Either would be an appropriate outcome and help ensure that demand side resources contribute to the competitiveness of capacity markets rather than suppressing the price below the competitive level.

As shown in Table 22, if no DR or EE had been offered into the auction, EMAAC and MAAC would have been the only modeled LDAs with binding constraints. EMAAC would have cleared at $391.59 per MW-day, and the cleared quantity would have been 30,492.3. MAAC would have cleared at $340.80 per MW-day, and the cleared quantity would have been 62,285.0 MW. The RTO would have cleared at $330.05 per MW-day, and the total cleared quantity would have been 147,144.0 MW.

If all DR and EE offers had been reduced to one third of the actual offers, for a total of 4,570.2 MW of DR and EE offered, EMAAC and MAAC would have been the only modeled LDAs with binding constraints. EMAAC would have cleared at $391.59 per MW-day, and the clearing quantity would have been 31,320.8. MAAC would have cleared at $340.80 per MW-day, and the clearing quantity would have been 64,293.8 MW. The RTO would have cleared at $133.12 per MW-day, and the total RTO cleared quantity would have been 151,320.9 MW. Cleared MW of DR and EE would have been 4,459.7 MW. In comparison, offered DR and EE in the 2012/2013 BRA totaled 10,500.3 MW, and cleared DR and EE totaled 7,616.1 MW as shown in Table 20.

If all DR and EE offers had been reduced to two thirds of the actual offers, for a total of 9,139.3 MW of DR and EE offered, MAAC and EMAAC would have been the only modeled LDAs with binding constraints. EMAAC would have cleared at $321.47 per MW-day, and the clearing quantity would have been 32,079.1 MW. MAAC would have cleared at $289.69 per MW-day, and the total MAAC cleared quantity would have been 66,229.4 MW. The RTO would have cleared at $43.66 per MW-day, and the total RTO cleared quantity would be 152,743.3 MW. Cleared MW of DR and EE would have been 7,407.2 MW.

Based on actual auction clearing prices and quantities and make-whole MW, total RPM market revenues for the 2013/2014 delivery year were $6,708,567,045. If no DR or EE had been offered into the auction, total RPM market revenues for the 2013/2014 delivery year would have been $18,535,847,876, a difference of $11,827,280,831 compared to the total based on actual results. If all DR and EE offers had been reduced to one third of the actual offers, total RPM market revenues for the 2013/2014 delivery year would have been $12,806,812,679, a difference of $6,098,245,634 compared to the total based on actual results. If all DR and EE offers had been reduced to two thirds of the actual offers, total RPM market revenues for the 2013/2014 delivery year would have been $8,753,672,929, a difference of $2,045,105,884 compared to the total based on actual results.

Tables and Figures for DR Analysis Section

Table 22 DR and EE offer impact

	Actual Auction Results		Two Thirds of Actual DR or EE		One Third of Actual DR or EE		No DR or EE Offers	
LDA	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
Pepco	$247.14	4,791.7	$289.69	5,094.3	$340.80	4,900.4	$340.80	4,705.8
EMAAC	$245.00	32,835.4	$321.47	32,079.1	$391.59	31,320.8	$391.59	30,492.3
MAAC	$226.15	67,639.9	$289.69	66,229.4	$340.80	64,293.8	$340.80	62,285.0
RTO	$27.73	152,743.3	$43.66	152,743.3	$133.12	151,320.9	$330.05	147,144.0

CETL/CETO

Since the ability to import energy and capacity into LDAs may be limited by the existing transmission capability, a load deliverability analysis is conducted for each LDA.[61] The first step in this process is to determine the transmission import requirement into an LDA, called the Capacity Emergency Transfer Objective (CETO). This value, expressed in unforced megawatts, is the transmission import capability required for each LDA to meet the area reliability criterion of loss of load expectation of one occurrence in 25 years when the LDA is experiencing a localized capacity emergency.

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

If CETL is less than CETO, transmission upgrades are planned under the Regional Transmission Expansion Planning (RTEP) Process. However, if transmission upgrades cannot be built prior to a delivery year to increase the CETL value, locational constraints could result under RPM, causing locational price differences.[62] Attachment A includes a table listing all the transmission upgrades included in the CETL/CETO modeling.[63]

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

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[61] See PJM. "Manual 14B: PJM Region Transmission Planning Process, Attachment C: PJM Deliverability Testing Methods," Revision 15 (April 21, 2010), p. 46, <http://www.pjm.com/~/media/documents/manuals/m14b.ashx >. Manual 14B indicates that all "electrically cohesive load areas" are tested.

[62] See PJM. "Manual 18: PJM Capacity Market," Revision 10 (Effective June 1, 2010), p. 10, < http://www.pjm.com/~/media/documents/manuals/m18.ashx > (1.32 MB).

[63] 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>

constrained LDAs regardless of the results of the above three tests.[64] 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."[65] A reliability requirement and a variable resource requirement curve are established for each modeled LDA.

Table 23 shows the CETL and CETO values used in the 2013/2014 study compared to the 2012/2013 values. The decrease in CETL for the MAAC and SWMAAC LDAs is mainly due to a change in the load distribution in the system model.[66] The 2013/2014 system model shows a significant increase in load in the northern Virginia area, resulting in higher loading of the Pleasant View 500/230 kV transformer which is the primary limit into the MAAC and SWMAAC LDA. The decrease in CETL for the EMAAC LDA is attributable primarily to the removal of the PPL portion of the Susquehanna-Roseland 500 kV project.

Table 23 PJM LDA CETL and CETO Values: 2012/2013 and 2013/2014 RPM Base Residual Auctions

	2012/2013			2013/2014			Change			
			CETL to CETO			CETL to CETO	CETO		CETL	
	CETO	CETL	Ratio	CETO	CETL	Ratio	MW	Percentage	MW	Percentage
MAAC	5,600	6,377	114%	4,190	4,460	106%	(1,410)	(25%)	(1,917)	(30%)
EMAAC	7,440	9,079	122%	7,050	7,095	101%	(390)	(5%)	(1,984)	(22%)
SWMAAC	5,990	7,400	124%	5,740	6,725	117%	(250)	(4%)	(675)	(9%)
PSEG	6,290	6,356	101%	5,950	5,868	99%	(340)	(5%)	(488)	(8%)
PSEG North	2,720	2,755	101%	2,620	2,570	98%	(100)	(4%)	(185)	(7%)
DPL South	1,520	1,746	115%	1,350	2,123	157%	(170)	(11%)	377	22%
Pepco	3,770	> 4335	> 115%	4,030	4,483	111%	260	7%	NA	NA

64 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.

65 See PJM OATT § 5.10(a)(ii) (Attachment DD: Reliability Pricing Model," Substitute First Revised Sheet No. 584 (Effective March 27, 2009)).

66 See PJM "2013/2014 RPM Base Residual Auction Planning Period Parameters," (March 12, 2010) <http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/planning-period-parameters-report.ashx> (169.51 KB).

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
b0452	Install 150 MVAR Capacitor at Northwest 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
b0487	Construct a Susquehanna - Roseland 500 kV circuit (PPL 500 kV equipment)	PPL
b0487.1	Install Lackawanna 500/230 kV transformation and upgrade 230 kV substation and switchyard	PPL
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

Upgrade ID	Description	Transmission Owner
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
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
b0750	Convert 138 kV network path from Vienna – Loretto – Piney Grove to 230 kV, add 230/138 kV transformer to Loretto 230 kV	DPL
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