Analysis of the 2012/2013 RPM Base Residual Auction

The Independent Market Monitor for PJM

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Introduction

This report, prepared by the Independent Market Monitor for PJM (IMM or MMU), reviews the functioning of the seventh Reliability Pricing Model (RPM) auction (for the 2012/2013 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 VRR curve; constrained LDAs; EFORd rule changes; the short term resource procurement target; the increased default ACR rates; the mitigation of Demand Resources; Demand Resources.

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. Thus, the reliability goal is to have total supply equal to or slightly above the demand for capacity. 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.

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.

Recent changes to the rules for the RPM auctions address the treatment of historical equivalent demand forced outage rates (EFORd) in determining the level of unforced capacity that must be offered. These changes include the elimination of EFORd risk segments from offers and the addition of a corresponding option to submit unforced capacity based on an EFORd up to the greater 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 data ending on September 30 prior to the auction. Under the previous rules, participants were required to submit unforced capacity based on an EFORd less than or equal to the EFORd based on 12 months of outage data.[1]

Effective for the 2012/2013 planning year, the load management product Interruptible Load for Reliability (ILR) was eliminated. It was replaced by the short-term resource procurement target. In prior Base Residual Auctions (BRA), PJM subtracted the ILR forecast from the reliability requirement. Under the current rules, 2.5 percent of the reliability requirement is removed from the demand curve. The ILR adjustment was equivalent to removing 1.2 percent of the reliability requirement in the 2011/2012 BRA. The stated rationale for this administrative reduction in demand in the BRA is to permit short lead time resource procurement in later auctions for the delivery year.

The Energy Efficiency (EE) resource type was eligible to be offered in RPM auctions for the first time for the 2012/2013 delivery year.

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 EFORd rates used, 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, PSEG North, and DPL South RPM markets failed the three pivotal supplier (TPS) test. All participants included in the incremental supply of EMAAC passed the 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 new units. The offer caps are designed to reflect the marginal cost of capacity. Based on these facts, the MMU concludes that the results of the 2012/2013 RPM Base Residual Auction were competitive.

Under the tariff, PJM determines, in advance of each BRA, whether defined Locational Deliverability Areas (LDAs) may be constrained in the auction. Under the rules in effect for the 2011/2012 BRA, an LDA with a Capacity Emergency Transfer Limit (CETL) greater than 1.05 times the Capacity Emergency Transfer Objective (CETO) was not permitted to constrain in the auction. That CETL to CETO ratio test of 1.05 was too restrictive and prevented significant locational price differences from occurring in the 2011/2012 base residual auction. Another recent change to the rules increased the CETL

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1 126 FERC ¶ 61,275 (2009).

to CETO threshold ratio used to determine the modeled LDAs for the 2012/2013 delivery year from 1.05 to 1.15.[2] The rules also provide that regardless of the test results, separate VRR curves will be established for any LDA with a locational price adder in one or more of the three immediately preceding BRAs, any LDA that PJM determines in a preliminary analysis is likely to have a locational price adder based on historic offer price levels, and EMAAC, SWMAAC, and MAAC LDAs.

Table 1 shows the clearing prices by LDA compared to the corresponding Net CONE values. The clearing prices were less than Net CONE for each LDA except DPL South.

Table 1 Clearing prices and net CONE

LDA	Clearing Price ($/MW-day)	Net CONE ($/MW-day)
RTO	$16.46	$276.09
MAAC	$133.37	$176.44
EMAAC	$139.73	$212.50
PSEG North	$185.00	$212.50
DPL South	$222.30	$212.50

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.[3] 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's reliability requirement and the PJM reliability requirement.[4]

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

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2 126 FERC ¶ 61,275 (2009).

3 See PJM Open Access Transmission Tariff (OATT), "Attachment DD: Reliability Pricing Model," Substitute Original Sheet No. 605 (Effective June 1, 2007), section 6.3 (a) (i).

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

suppliers.[5] Capacity resource owners who own or control generation in the area that fails the PMSS are required to provide avoidable cost rate (ACR) data to the MMU.[6]

Consistent with the requirements of the Tariff, the MMU applied the PMSS two months prior to the 2012/2013 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 data to the MMU for resources for which they intended to submit non-zero sell offers unless certain other conditions were met.[7] There were no provisional exceptions for the 2012/2013 Auction.

Table 2 Preliminary Market Structure Screen results: 2012/2013

RPM Markets	Highest Market Share	HHI	Pivotal Suppliers	Pass/Fail
RTO	17.4%	853	1	Fail
MAAC	17.6%	1071	1	Fail
EMAAC	32.8%	2057	1	Fail
SWMAAC	50.7%	4338	1	Fail
PSEG	84.3%	7188	1	Fail
PSEG North	90.9%	8287	1	Fail
DPL South	55.0%	3828	1	Fail

Offer Caps

The defined capacity resource owners were required to submit ACR data to the MMU by six weeks prior to the 2012/2013 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.

5 See PJM Open Access Transmission Tariff (OATT), "Attachment DD: Reliability Pricing Model," Original Sheet No. 605A (Effective June 1, 2007), section 6.3 (a) (ii).

6 See PJM Open Access Transmission Tariff (OATT), "Attachment DD: Reliability Pricing Model," Third Revised Sheet No. 610 (Effective March 27, 2009). The required data are defined at section 6.7.

7 See PJM Open Access Transmission Tariff (OATT), "Attachment DD: Reliability Pricing Model," Third Revised Sheet No. 610 (Effective March 27, 2009), section 6.7 (c).

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.[8] 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 maintain a unit as a capacity resource. Avoidable costs 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.

Capacity resource owners could provide ACR data by providing their own unit-specific data, by selecting the default ACR values or by submitting an opportunity cost for a possible export or a potential import. The default ACR values for both the mothball and the retirement options were calculated by the MMU based on available unit data, posted to the Monitoring Analytics Web site and included in the tariff, 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 opportunity cost option allows resource owners to input a documented export opportunity cost as the offer for the unit. 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.

Effective with this auction, ACR default rates were increased.

As shown in Table 3, 1,133 generating resources submitted offers compared to 1,125 generating resources offered in the 2011/2012 RPM Base Residual Auction. The net increase of eight resources consisted of 16 new resources (772.5 MW), four resources that were previously entirely Fixed Resource Requirement (FRR) committed (13.4 MW), three additional resources imported (276.8 MW), two additional resources resulting from disaggregation of RPM resources, and one resource formerly unoffered (1.9 MW), offset by nine retired resources (1,044.5 MW), four additional resources committed fully to FRR (39.5 MW), four less resources resulting from aggregation of RPM resources, and one less external resource that did not offer (663.2 MW).[9] In addition, there were the

[8] See PJM Open Access Transmission Tariff (OATT), "Attachment DD: Reliability Pricing Model," First Revised Sheet No. 617 (Effective January 19, 2008), section 6.8 (b).

[9] Disaggregation and aggregation of RPM resources reflect changes in how units are offered in RPM. For example, multiple units at a plant may be offered as a single unit or multiple units.

following retirements of resources that were either exported or excused in the 2011/2012 BRA: two combustion turbine resources (5.3 MW) and three combined cycle resources (297.6 MW). Also, resources that are no longer PJM capacity resources consisted of three CT units (521.5 MW) in the RTO. The publicly posted future deactivation requests include Hudson 1 (159.5 MW) in PSEG North; Benning 15 (233.8 MW), Benning 16 (233.8 MW), Buzzard Point CT East (100.8 MW), and Buzzard Point CT West (115.2 MW) in MAAC; and Will County Coal 1 (133.4 MW) and Will County Coal 2 (142.5 MW) in RTO. In addition, resources that are no longer capacity resources but do not have public notifications of future deactivations consisted of two CT resources (185.5 MW) in PSEG North; one CT resource (1.1 MW), one diesel resource (5.5 MW), one steam unit (10.4 MW), and one combined cycle resource (21.7 MW) in EMAAC; and one CT (4.2 MW) in MAAC. The new units consisted of six new diesel resources (13.9 MW), four new wind resources (57.9 MW), three new steam units (560.4 MW), two new CT units (85.2 MW), and one new combined cycle unit (55.1 MW).[10] There were 233 demand resources (DR) offered compared to 37 DR resources offered in the 2011/2012 RPM Base Residual Auction. There were 53 Energy Efficiency (EE) resources offered as a new resource type for the 2012/2013 planning year.

The MMU calculated 610 offer caps, of which 479 were based on the technology specific default (proxy) ACR values calculated by the MMU.[11] Unit-specific offer caps were calculated for 120 units (10.6 percent) including 118 units (10.4 percent) with an Avoidable Project Investment Recovery Rate (APIR) component and 2 units (0.2 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 1,133 generating units, 11 new resources had uncapped offers while the remaining 515 generating resources were price takers, of which the offers for 512 resources were zero and the offers for three resources were set to zero because no data were submitted.[12]

As shown in Table 4, the weighted-average gross ACR for units with APIR ($464.65 per MW-day) and the weighted-average offer caps, net of net revenues, for units with APIR ($167.62 per MW-day) increased from the 2011/2012 values of $424.49 per MW-day and $147.77 per MW-day, respectively, due to higher ACRs for subcritical/supercritical coal

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

11 Three resources had both ACR based and opportunity cost based offer caps calculated.

12 Planned units are subject to mitigation only under specific conditions defined in the tariff. Some of the 11 uncapped planned units submitted zero price offers. See PJM Open Access Transmission Tariff (OATT), "Attachment DD: Reliability Pricing Model," Substitute Second Revised Sheet No. 607 (Effective March 27, 2009), section 6.5 (a) ii.

and CC units with APIR. Offer caps for units without an APIR component, including units for which the default value was selected, decreased from $45.80 per MW-day to $21.55 per MW-day due to lower submitted opportunity costs and higher net revenues for CC and CT units.[13] The APIR component added $351.74 per MW-day to the ACR value of the APIR units compared to $324.58 per MW-day in 2011/2012.[14,15] The default ACR values include an average APIR of $1.31 per MW-day compared to $0.91 per MW-day in the 2011/2012 BRA. The highest APIR for a technology ($559.97 per MW-day) was for subcritical/supercritical coal units. The maximum APIR effect ($1,155.57 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

13 The 2011/2012 APIR statistics were revised since the 2011/2012 BRA report was posted.

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

15 The 118 units which had an APIR component submitted $567.2 million for capital projects associated with 11,124.8 MW of UCAP.

Table 3 ACR statistics: 2012/2013 RPM Base Residual Auction[16]

Calculation Type	Number of Resources	Percent of Generation Resources Offered
Default ACR selected	476	42.0%
ACR data input (APIR)	118	10.4%
ACR data input (non-APIR)	2	0.2%
Opportunity cost input	8	0.7%
Default ACR and opportunity cost input	3	0.3%
Generating resources with offer caps	607	53.6%
Uncapped new generation resources	11	1.0%
Generation price takers	515	45.5%
Generation resources offered	1,133	100.0%
Capped existing demand resources	163	
Uncapped planned demand resources	38	
Demand resources with existing and planned portions	32	
Demand resources offered	233	
Uncapped energy efficiency resources	53	
Energy efficiency resources offered	53	
Total capacity resources offered	1,419	

16 The classification of DR resources as planned includes only DR resources that offered planned MW at non-zero sell offer prices; it does not include planned DR MW that were offered at $0 per MW-day.

Table 4 APIR statistics: 2012/2013 RPM Base Residual Auction[17]

	Weighted-Average ($ per MW-day UCAP)						
	Combined Cycle	Combustion Turbine	Oil or Gas Steam	SubCritical/ SuperCritical Coal	Other	Opportunity Costs	Total
Non-APIR units							
ACR	$41.84	$32.61	$75.47	$207.54	$57.18		$110.84
Net revenues	$91.67	$35.29	$7.51	$396.82	$257.96		$208.65
Offer caps	$5.28	$14.40	$67.96	$11.31	$15.63	$136.48	$21.55
APIR units							
ACR	$218.10	$49.83	$177.52	$715.10	N/A		$464.65
Net revenues	$98.97	$15.62	$3.62	$508.00	N/A		$302.04
Offer caps	$119.12	$34.96	$173.89	$215.38	N/A		$167.62
APIR	$218.10	$26.59	$89.08	$559.97	N/A		$351.74
Maximum APIR effect							$1,155.57

RPM Auction Results

MMU Methodology

The MMU reviewed the following inputs to and results of the 2012/2013 RPM auction: [18]

- **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 2006 through 2008;

- **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;

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17 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.

18 All volumes and prices are in terms of unforced capacity (UCAP), which is calculated as installed capacity (ICAP) times (1-EFORd). The EFORd values in this report are the EFORd values used in the 2012/2013 RPM Base Residual 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, 2008;

- **Clearing Prices –** Verified that the auction clearing prices were accurate, based on submitted offers and the 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 5, all participants in the RTO as well as MAAC, PSEG North, and DPL South RPM markets failed the TPS test.[19] All participants included in the incremental supply of EMAAC passed the 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 new units. The RTO market includes all supply. The constrained LDA markets include the incremental supply inside the constrained LDAs which was offered at a price higher than the unconstrained clearing price for the parent LDA market.

The incremental demand consists of the MW needed inside the LDA to relieve the constraint. Incremental demand in EMAAC was 18.6 MW. The incremental supply in EMAAC, considered in the application of the three pivotal supplier test, was 883.1 MW, including all offered MW with sell offer prices greater than the MAAC clearing price of $133.37 per MW-day and less than or equal to 1.5 times the EMAAC clearing price of $139.73 per MW-day. There were six parent companies in EMAAC with incremental supply resources. One company supplied the 18.6 MW needed to meet the incremental demand, all of which were DR resources.

Table 5 presents the results of the TPS 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_x). The RSI_x is a general measure that can be used with any number of 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

19 See the *2008 State of the Market Report for PJM*, 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.

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.[20] MAAC/SWMAAC are presented together because SWMAAC was modeled but was not a constrained LDA in this auction. Similarly, EMAAC/PSEG are presented together because PSEG was modeled but was not a constrained LDA in this auction.

Table 5 RSI Results: 2012/2013 RPM Base Residual Auction

	$RSI_{1\ 1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
RTO	0.84	0.63	98	98
MAAC/SWMAAC	0.77	0.54	15	15
EMAAC/PSEG	0.00	7.03	6	0
PSEG North	0.00	0.00	2	2
DPL South	0.00	0.00	3	3

RTO

Table 6 shows total RTO offer data for the 2012/2013 RPM Base Residual Auction. All MW values stated in the RTO section include all nested LDAs. Nested LDAs occur when a constrained LDA is a subset of a larger constrained LDA or the RTO. For example, MAAC is nested in the RTO as all other LDAs. As another example, EMAAC, PSEG North and DPL South are all nested in MAAC. Total internal RTO unforced capacity increased 10,070.6 MW (6.3 percent) from 159,882.7 MW in the 2011/2012 RPM BRA to 169,953.3 MW as a result of new generation (772.5 MW), capacity upgrades to existing generation and increases in DR and EE, net of derations to existing generation and demand capacity resources. As shown in Table 7, of the 10,070.6 MW increase, 3,187.2 MW were due to the reclassification of the Duquesne zone to internal, -851.8 MW were net generation capacity modifications (cap mods), 8,028.7 MW were net DR modifications (DR mods), and 652.5 MW were the newly offered EE resource.[21] A decrease of 944.1 MW (0.59 percent) was due to higher sell offer EFORds, and the remaining decrease of 1.9 MW was due to a lower Load Management UCAP conversion

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20 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 *2008 State of the Market Report for PJM* (March 11, 2009), Appendix L, "Three Pivotal Supplier Test" for additional discussion.

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

factor compared to the 2011/2012 BRA.[22, 23] Total internal RTO unforced capacity includes all generating units, DR, and EE that qualified as PJM capacity resources for the 2012/2013 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.[24] 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.[25] Otherwise the owner must take an outage, as appropriate, if the owner cannot provide energy consistent with the ICAP of the unit.

Multiple owners submitted both positive and negative capacity modifications, with a net RTO increase of 7,154.8 MW of ICAP and 7,829.4 MW of UCAP (Table 7 and Table 8). Cap mod increases and decreases were the result of owner reevaluation of the capabilities of their generation and DR, 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 149,520.1 MW compared to 142,263.1 MW in the 2011/2012 RPM Base Residual Auction.[26] FRR volumes increased by 225.2 MW, and imports

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22 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 2011/2012 BRA, this conversion factor was 0.955*1.0833 = 1.0346. For the 2012/2013 BRA, this factor was .950*1.0872 = 1.0328. 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.

23 See "PJM Manual 20: PJM Resource Adequacy Analysis," Revision 03 (June 1, 2007), p. 8-10 Hhttp://www.pjm.com/documents/~/media/documents/manuals/m18.ashx (662.9 KB).

24 See "Reliability Assurance Agreement among Load-Serving Entities in the PJM Region," (June 1, 2007) (Accessed May 20, 2009) < http://www.pjm.com/documents/agreements/~/media/documents/agreements/raa.ashx> (1.92 MB).

25 See "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," Revision 05 (June 1, 2008), p. 11 < http://www.pjm.com/documents/~/media/documents/manuals/m21.ashx> (105.11 KB). The manual states "the end of the next planning period."

26 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.

decreased by 2,588.4 MW. RPM capacity was reduced by exports of 2,637.1 MW and 44.2 MW which were excused from the RPM must offer requirement as a result of planned reductions due to environmental regulations (34.5 MW) and other factors (9.7 MW). Exports decreased 521.3 MW, and excused volumes decreased 304.6 MW from the 2011/2012 RPM auction. Subtracting 1,465.5 MW of FRR optional volumes not offered, an increase of 429.9 MW in FRR MW not offered from the 2011/2012 RPM Base Residual Auction, resulted in 145,373.3 MW that were available to be offered into the auction, an increase of 7,653.0 MW.[27] 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 $16.46 per MW-day.

As shown in Figure 4, the RTO clearing price decreased from $110.00 per MW-day in the 2011/2012 Base Residual Auction to $16.46 per MW-day in the 2012/2013 auction. The RTO clearing price decreased from $80.00 per MW-day, using the price calculated by the MMU, accounting for economic LDA price separation.[28] Offered volumes increased 7,653.0 MW from 137,720.3 MW to 145,373.3 MW, while the overall RTO reliability requirement, from which the demand curve is developed, increased 3,073.7 MW from 130,658.7 MW to 133,732.4 MW.[29] The increase in the reliability requirement, due to the inclusion of the Duquesne control zone in the preliminary forecast peak load, shifted the RTO market demand curve to the right.

As shown in Table 6, the net load price that LSEs will pay is $16.46 per MW-day in the RTO. The final zonal capacity price will be calculated after the third incremental auction if no conditional incremental auctions are held.

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27 FRR entities are allowed to offer into the RPM auction excess volumes above their FRR quantities, subject to a sales cap amount. The 1,465.5 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.

28 See "Analysis of the 2011/2012 RPM Auction" (Revised October 1, 2008) < Hhttp://www.monitoringanalytics.com/reports/Reports/2008/20081002-review-of-2011-2012-rpm-auction-revised.pdf >

29 The demand curve UCAP quantities are based on three points, which are ratios of the installed reserve margin (IRM = 16.2 percent) times the reliability requirement, less the forecast RTO ILR obligation. For the three points, the ratios are 1.132/1.162, 1.172/1.162 and 1.212/1.162. For these three points the UCAP prices are based on factors multiplied by net cost of net 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.

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 6, the 136,143.5 MW of cleared resources for the entire RTO, which represented a reserve margin of 20.9 percent, resulted in net excess of 5,754.4 MW over the reliability requirement of 133,732.4 MW (IRM of 16.2 percent).[30, 31] Net excess increased 2,597.8 MW from the net excess of 3,156.6 MW in the 2011/2012 RPM auction. As shown in Figure 1, the downward sloping demand curve resulted in a price of $16.46 per MW-day. The 9,229.8 MW of uncleared volumes in the entire RTO were the result of offer prices which exceeded the clearing prices. Of the uncleared MW in the entire RTO, 83.8 MW were EE offers, 2,800.4 MW were DR offers, and the remaining 6,345.6 MW were generation offers. Table 9 presents details on the generation offers that did not clear.

If the demand curve had been vertical at the reliability requirement less the short-term resource procurement with the same maximum price set at 1.5 times the net Cost of New Entry (CONE) and the RTO cleared as a single market, the clearing price would have been $25.23 per MW-day as shown in Figure 2. If the given LDAs were modeled and the demand curves had been vertical at the LDA reliability requirements less the LDA short-term procurement targets, MAAC, DPL South, and PSEG North would have had binding constraints, and EMAAC, SWMAAC, and PSEG would not have had binding constraints. The RTO would have cleared at $0.05 per MW-day as shown in Figure 3.

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. This was illustrated by

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30 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.

31 The IRM increased from 15.5 percent to 16.2 percent for the 2012/2013 delivery year.

the difference in results for the 2011/2012 BRA between PJM, which did not incorporate any constraints, and the MMU, which did incorporate economic constraints.

The impact of constraints on relative prices was even more significant in the 2012/2013 BRA. There were four binding constraints in the 2012/2013 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 2012/2103 BRA. If no LDAs had been modeled in this auction and the RTO had cleared as a single market, the RTO would have cleared at $73.32 per MW-day. If only PSEG North and DPL South had been modeled, the RTO would have cleared at $70.30 per MW-day. If, in addition, EMAAC had been modeled, the RTO would have cleared at $53.67 MW-day. Finally, adding MAAC as a constrained LDA results in the RTO market clearing at $16.46 per MW-day. MAAC was the largest LDA in terms of cleared MW and had a correspondingly large impact on the clearing price in the RTO.

If the market had cleared as a single market, total RPM market revenues for the 2012/2013 delivery year would have been $3,633,347,891. If only PSEG North and DPL South had been constrained, total RPM market revenues for the 2012/2013 delivery year would have been $3,701,633,882. If, in addition, EMAAC had been constrained, total RPM market revenues for the 2012/2013 delivery year would have been $3,738,888,715. Based on actual auction clearing prices and quantities, total RPM market revenues for the 2012/2013 delivery year were $3,783,207,927.

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.

There is another way to describe the mechanics of the impact of constrained LDAs on the RTO market. Rather than shifting the demand curve in the RTO market to the left, the mechanics can be described as shifting the supply curve to the right by the amount of capacity cleared in the constrained LDAs plus the CETL amounts that med load in the constrained LDAs. This is the approach presented in the PJM report. In this approach, the demand curve is represented by the original VRR points. The result is the same. Note that this does not mean that the supply from the LDAs is literally offered at zero in the RTO market, but is simply a way to describe the mechanics of clearing locational markets.

Mitigated and Unmitigated Supply Curves

Figure 6 shows the RTO unmitigated and mitigated 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 48 mitigated DR resources, including 1,874.7 MW, and 39 mitigated generating resources, including 3,758.6 MW, for a total of 5,633.3 MW that cleared with mitigated offers.

Composition of the Steeply Sloped Portion of the Supply Curve

Table 10 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 $425.00 per MW-day. Offers based on opportunity costs made up 13.1 percent of the offers on this section of the supply curve while oil/gas steam, combustion turbines and coal units made up 66.9 percent of the offers, most with APIR. The last offer to clear in the RTO was for a CT unit without APIR.

Impacts of Rule Changes Affecting EFORd

Recent changes to the rules for the RPM auctions address the treatment of historical EFORd used in determining the level of unforced capacity that must be offered. These changes include the elimination of the EFORd risk segments and the addition of a corresponding option to submit unforced capacity based on an EFORd up to the greater 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. Under the previous rules, participants were required to submit unforced capacity based on an EFORd less than or equal to the EFORd based on 12 months of outage data.[32] The EFORd offer segment was designed to address the risk of a change in EFORd between the auction and the delivery year. A participant could submit a sell offer where the sell offer price for the EFORd segment was no greater than the net CONE. The MW quantity in the EFORd segment could be no greater than the summer net capability ICAP times the positive difference between the five-year EFORd and one-year EFORd, or the positive difference between the EFORd reasonably anticipated for the 12 months ending on September 30 prior to the delivery year and the average EFORd for the 12 months ending on September 30 prior to the auction.

32 126 FERC ¶ 61,275 (2009).

If participants had not been given the option to use the five-year EFORd and had been required to use the one-year EFORd, the result would have been more UCAP MW offered into the auction. The total internal RTO unforced capacity would have been 171,155.0 MW compared to the actual 169,953.3 MW, a difference of 1,201.7 MW. When comparing UCAP MW levels from one auction to another, two variables, capacity modifications and EFORd changes, need to be considered. The part of the net internal capacity change attributed to capacity modifications can be determined by holding the EFORd level constant at the prior auction's level. The EFORd effect is the measure of the net internal capacity change attributable to EFORd changes and not capacity modifications. The EFORd effect was -944.1 MW. As shown in Table 8, the net capacity increase was 7,829.4 MW, holding the sell offer EFORds constant at the 2011/2012 BRA level. 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 161.9 MW compared to the actual EFORd effect of -944.1 MW, a difference of 1,106.0 MW. The Duquesne generating resources would have had a total UCAP of 3,282.9 MW compared to the actual 3,187.2 MW, a difference of 95.7 MW. If the one EFORd values had been used rather than the higher of the five year and the one year, the net internal capacity increase would have been 11,272.3 MW rather than the actual net internal capacity increase of 10,070.6 MW, a difference of 1,201.7 MW.

Table 11 shows the auction results if the maximum EFORd which participants could submit had been the one-year EFORd and if all eligible participants had submitted EFORd offer segments where the sell offer price was at net CONE and the MW value was equal to the ICAP times the positive difference between the five-year EFORd and the one-year EFORd. More UCAP MW would have been offered as a result of lower sell offer EFORds, and sell offer prices would have been higher for the EFORd offer segments. The binding constraints would have remained the same. PSEG North and DPL South clearing prices and quantities would have remained the same. EMAAC would have cleared at $138.00 per MW-day with a total EMAAC clearing quantity of 31,094.3 MW. MAAC would have cleared at $133.37 per MW-day with a total MAAC clearing quantity of 65,452.4 MW. The RTO would have cleared at $16.59 per MW-day compared to the actual clearing price of $16.46 per MW-day. The entire RTO clearing quantity would have remained the same at 136,143.5 MW. The conclusion is that the five-year EFORd option together with the elimination of the EFORd offer segment did not have a significant impact on the market results.

If the maximum EFORd which participants could submit was the one-year EFORd and participants could not submit EFORd offer segments, the UCAP conversion would have been affected, resulting in more UCAP MW offered into the auction. PSEG North and DPL South clearing prices and quantities would have remained the same. EMAAC would not have constrained and would have cleared with MAAC. MAAC would have cleared at $123.51 per MW-day compared to $133.37 per MW-day. The RTO would have cleared at $14.84 per MW-day compared to the actual clearing price $16.46 per MW-day.

(See Table 11) The conclusion is that the inclusion of the maximum of the five-year or the one-year EFORd had a relatively small impact on the market results.

ILR and the Short Term Resource Procurement Target

Effective for the 2012/2013 planning year, ILR was eliminated. It was replaced by the short-term resource procurement target. Prior to this, PJM subtracted the ILR forecast from the reliability requirement. Under the current rules, 2.5 percent of the reliability requirement is removed from the demand curve. The rationale is to provide for short lead time resource procurement in incremental auctions for the given delivery year. For the 2012/2013 BRA, the 2.5 percent reduction resulted in the removal of 3,343.3 MW from the RTO demand curve. 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 12 shows the results if the reliability requirements had not been reduced by 2.5 percent short-term resource procurement target and everything else had remained the same. The clearing price for DPL South would have been the same, but the clearing quantity would have increased to 1,305.5 MW. PSEG North would not have constrained, but clearing prices would have been the same as PSEG North would have cleared with EMAAC and the clearing quantity would have increased to 3,558.2 MW. The EMAAC clearing price would have increased to $185.00 per MW-day and the clearing quantity would have increased to 31,635.0 MW. The MAAC clearing price would have increased to $175.00 per MW-day and the clearing quantity would have increased to 66,394.0 MW. The RTO clearing price would have increased to $23.92 per MW-day and the clearing quantity would have increased to 139,486.8 MW.

The conclusion is that the removal of 2.5 percent of demand did not have a significant impact on DPL South or PSEG North but did have a significant impact on EMAAC and MAAC and on the RTO market. The removal of 2.5 percent of demand reduced the clearing prices and quantities for EMAAC, MAAC and the RTO. Table 19 shows the combined impact of not mitigating DR offers and not making the 2.5 percent demand adjustment. The conclusion is the same.

The MMU recommends the careful reconsideration of the use of the 2.5 percent demand adjustment. The logic of reducing demand in a market design that looks three years forward, to permit other resources to clear in incremental auctions, is questionable. 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 2012/2013 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, although clearing prices in the two small constrained eastern LDAs were not affected.

The result was also to significantly reduce the clearing price for the RTO market, affecting substantial MW of capacity.

Impact of Increased ACR Default Rate

Effective this auction, ACR default rates were increased. If offer caps had been calculated based on the old default ACR rates, all binding constraints would have remained the same. The LDA clearing prices and quantities would have remained the same. The RTO would have cleared at $12.20 per MW-day compared to the actual clearing price of $16.46 per MW-day, and the total RTO clearing quantity would have remained the same at 136,143.5 MW.

Tables and Figures for RTO Section

Table 6 RTO offer statistics: 2012/2013 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Total internal RTO capacity (gen, DR, and EE)	179,791.2	169,953.3		
FRR	(26,302.1)	(24,264.8)		
Imports	4,152.4	3,831.6		
RPM capacity	157,641.5	149,520.1		
Exports	(2,783.9)	(2,637.1)		
FRR optional	(1,684.2)	(1,465.5)		
Excused	(48.0)	(44.2)		
Available	153,125.4	145,373.3	100.0%	100.0%
Generation offered	142,957.7	134,873.0	93.4%	92.8%
DR offered	9,535.4	9,847.6	6.2%	6.8%
EE offered	632.3	652.7	0.4%	0.4%
Total offered	153,125.4	145,373.3	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO	132,793.4	126,399.2	86.7%	87.0%
Cleared in LDAs	10,569.3	9,744.3	6.9%	6.7%
Total cleared	143,362.7	136,143.5	93.6%	93.7%
Uncleared in RTO	6,587.8	6,399.7	4.3%	4.4%
Uncleared in LDAs	3,174.9	2,830.1	2.1%	1.9%
Total uncleared	9,762.7	9,229.8	6.4%	6.3%
Reliability requirement		133,732.4		
Total cleared		136,143.5		
Short-Term Resource Procurement Target		3,343.3		
Net excess/(deficit)		5,754.4		
Resource clearing price ($ per MW-day)		$16.46	A	
Preliminary zonal capacity price ($ per MW-day)		$16.46	B	
Base zonal CTR credit rate ($ per MW-day)		$0.00	C	
Preliminary net load price ($ per MW-day)		$16.46	B-C	

Table 7 Capacity modifications (ICAP): 2012/2013 RPM Base Residual Auction[33]

	ICAP (MW)				
	RTO	MAAC	EMAAC	PSEG NORTH	DPL SOUTH
Generation increases	1,764.9	695.6	(1,003.0)	47.3	0.0
Generation decreases	(3,018.3)	(1,906.2)	336.0	(815.0)	(34.8)
Capacity modifications net increase/(decrease)	(1,253.4)	(1,210.6)	(667.0)	(767.7)	(34.8)
DR increases	9,006.0	4,586.6	(187.6)	65.4	62.5
DR decreases	(1,229.9)	(876.9)	1,621.8	0.0	0.0
DR modifications increase/(decrease)	7,776.1	3,709.7	1,434.2	65.4	62.5
EE increases	632.1	181.2	23.8	0.9	0.0
Net capacity/DR modifications increase/(decrease)	7,154.8	2,680.3	791.0	(701.4)	27.7
Duquesne Gen	3,210.0				
Duquesne DR	184.6				
Duquesne EE	0.2				
Net Internal Capacity Increase/(Decrease)	10,549.6	2,680.3	791.0	(701.4)	27.7

Table 8 Capacity modifications (UCAP): 2012/2013 Base Residual Auction

	UCAP (MW)				
	RTO	MAAC	EMAAC	PSEG NORTH	DPL SOUTH
Generation increases	1,655.8	661.3	328.0	42.3	0.0
Generation decreases	(2,507.6)	(1,500.7)	(713.2)	(551.3)	(31.8)
Capacity modifications net increase/(decrease)	(851.8)	(839.4)	(385.2)	(509.0)	(31.8)
DR increases	9,301.0	4,736.8	1,674.9	67.6	64.6
DR decreases	(1,272.3)	(907.1)	(194.0)	0.0	0.0
DR modifications increase/(decrease)	8,028.7	3,829.7	1,480.9	67.6	64.6
EE increases	652.5	186.9	24.4	0.9	0.0
Net capacity/DR modifications increase/(decrease)	7,829.4	3,177.2	1,120.1	(440.5)	32.8
EFORd effect	(944.1)	(502.1)	(185.1)	18.3	5.8
DR effect	(1.9)	(0.9)	(0.5)	0.0	0.0
Duquesne Gen	2,996.2				
Duquesne DR	190.8				
Duquesne EE	0.2				
Net Internal Capacity Increase/(Decrease)	10,070.6	2,674.2	934.5	(422.2)	38.6

[33] Only cap mods and DR mods that had a start date on or before June 1, 2012 are included.

Table 9 Uncleared generation offers: 2012/2013 RPM Base Residual Auction

LDA	Technology Type	Age	Uncleared UCAP (MW)
PSEG North	Combustion Turbine	Planned	223.4
DPL South	SubCritical / SuperCritical Coal	20 to 30 years old	112.6
		30 to 40 years old	144.8
EMAAC	Combustion Turbine	Planned	223.4
	Oil or Gas Steam	10 to 20 years old	29.4
		30 to 40 years old	345.6
		40 to 50 years old	127.4
		Greater than 50 years old	183.6
	SubCritical / SuperCritical Coal	20 to 30 years old	112.6
		30 to 40 years old	144.8
		40 to 50 years old	444.6
		Greater than 50 years old	137.6
SWMAAC	Combustion Turbine	Planned	240.0
		30 to 40 years old	51.3
	Oil or Gas Steam	Greater than 50 years old	206.0
	SubCritical / SuperCritical Coal	40 to 50 years old	219.3
MAAC	Combustion Turbine	Planned	463.4
		30 to 40 years old	51.3
	Oil or Gas Steam	10 to 20 years old	29.4
		30 to 40 years old	394.6
		40 to 50 years old	127.4
		Greater than 50 years old	389.6
	Hydro	Greater than 50 years old	3.0
	SubCritical / SuperCritical Coal	20 to 30 years old	112.6
		30 to 40 years old	144.8
		40 to 50 years old	663.9
		Greater than 50 years old	137.6
RTO	Combustion Turbine	Planned	463.4
		Less than 10 years old	3,143.4
		30 to 40 years old	90.4
	Oil or Gas Steam	10 to 20 years old	29.4
		30 to 40 years old	605.4
		40 to 50 years old	127.4
		Greater than 50 years old	389.6
	SubCritical / SuperCritical Coal	Planned	117.1
		20 to 30 years old	112.6
		30 to 40 years old	144.8
		40 to 50 years old	685.3
		Greater than 50 years old	416.8
	Wind	Planned	17.0
	Hydro	Greater than 50 years old	3.0

Table 10 Offers greater than $35.00 on total RTO supply curve: 2012/2013 RPM Base Residual Auction

Offer/Technology Type	UCAP (MW)	Percent of Offers
DR	2,405.6	18.9%
EE	91.1	0.7%
Opportunity costs	1,664.9	13.1%
Oil/gas steam	2,807.6	22.1%
Supercritical coal	2,292.2	18.0%
Subcritical coal	1,790.5	14.1%
Combustion turbine (CT)	1,624.0	12.8%
Combined cycle	42.4	0.3%
Total	12,718.3	100.0%

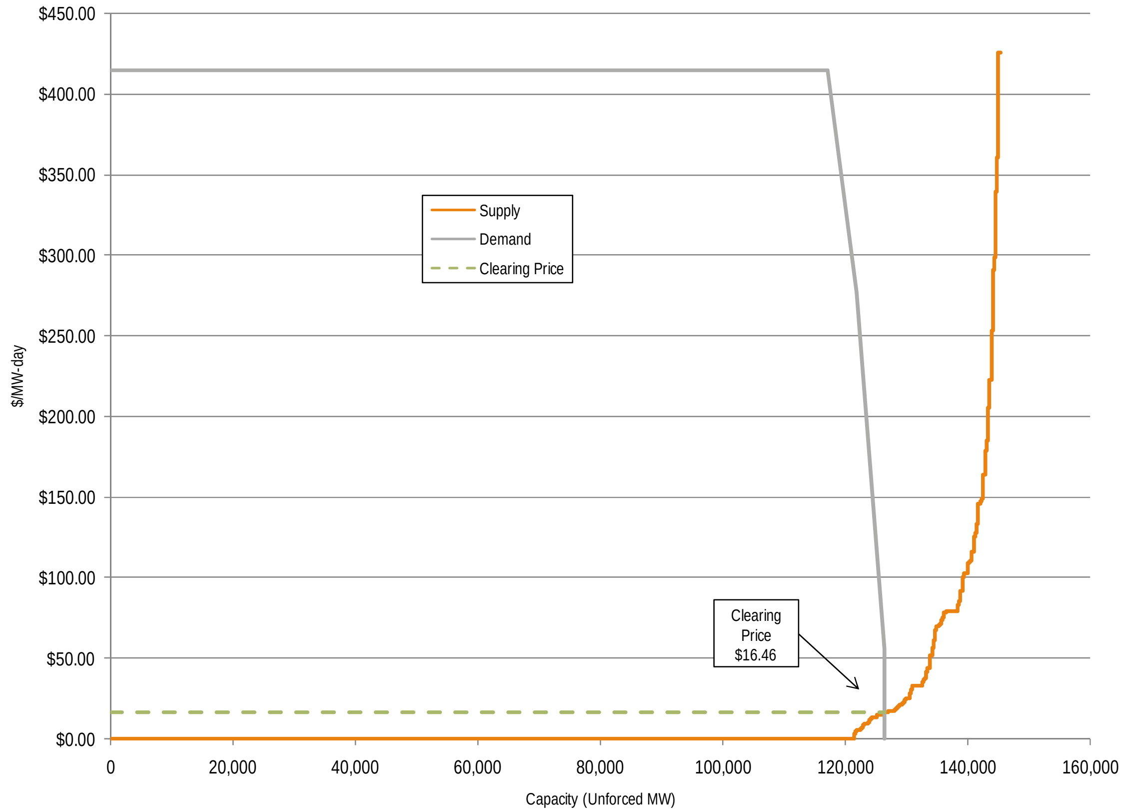
Table 11 Impact of EFORd-5 and elimination of EFORd risk offer segments

	Actual Auction Results		Without EFORd-5 Option		With EFORd Risk Offer Segment Option and Without EFORd-5 Option	
LDA	Clearing Prices ($/MW-day)	Cleared UCAP (MW)	Clearing Prices ($/MW-day)	Cleared UCAP (MW)	Clearing Prices ($/MW-day)	Cleared UCAP (MW)
DPL South	$222.30	1,241.5	$222.30	1,241.5	$222.30	1,241.5
PSEG North	$185.00	3,521.9	$185.00	3,521.9	$185.00	3,521.9
EMAAC	$139.73	31,080.2	$123.51	31,426.4	$138.00	31,094.3
MAAC	$133.37	65,452.4	$123.51	65,625.9	$133.37	65,452.4
RTO	$16.46	136,143.5	$14.84	136,143.5	$16.59	136,143.5

Table 12 Impact of not reducing demand by short-term resource procurement

	Actual Auction Results		Without Short-Term Resource Procurement Reduction	
LDA	Clearing Prices ($/MW-day)	Cleared UCAP (MW)	Clearing Prices ($/MW-day)	Cleared UCAP (MW)
DPL South	$222.30	1,241.5	$222.30	1,305.5
PSEG North	$185.00	3,521.9	$185.00	3,558.2
EMAAC	$139.73	31,080.2	$185.00	31,635.0
MAAC	$133.37	65,452.4	$175.00	66,394.0
RTO	$16.46	136,143.5	$23.92	139,486.8

Figure 1 PJM RTO market supply/demand curves: 2012/2013 RPM Base Residual Auction[34]



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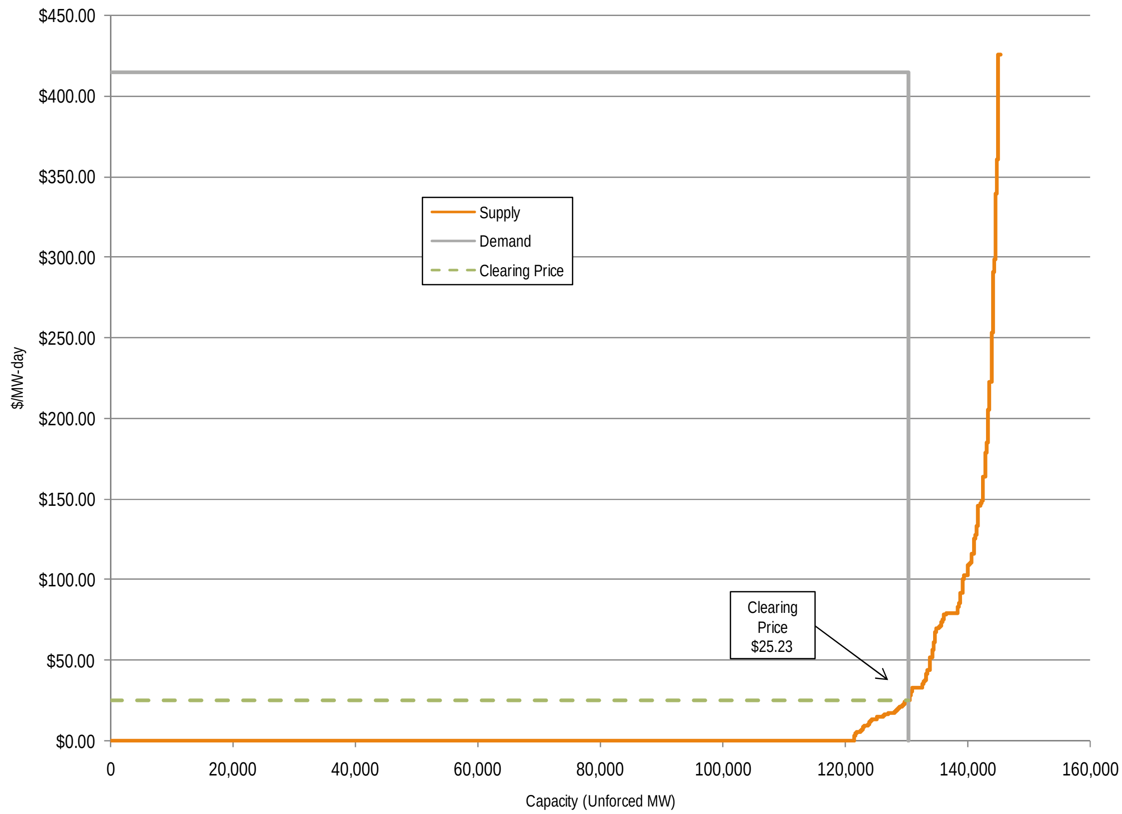
34 The supply curve includes all supply offers at the lower of offer price or offer cap. The demand curve excludes incremental demand which cleared in MAAC, EMAAC, PSEG North, and DPL South.

Figure 2 PJM as a single market supply/demand curves at reliability requirement: 2012/2013 RPM auction[35]



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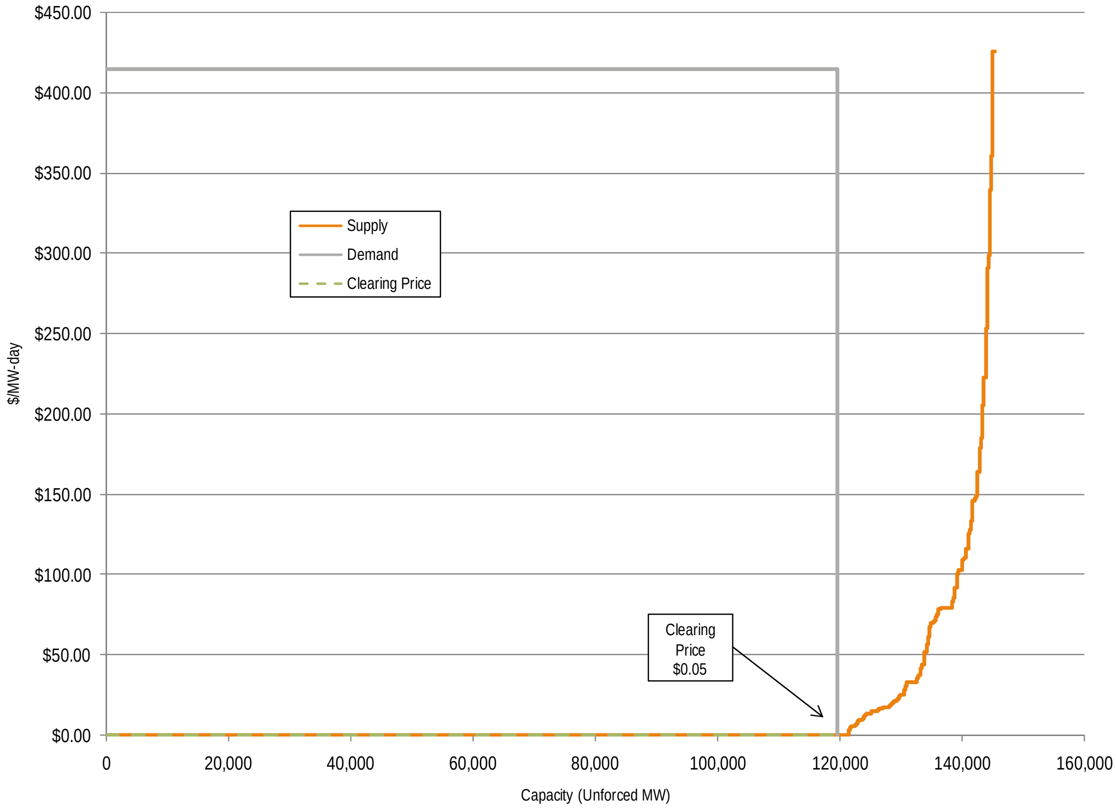
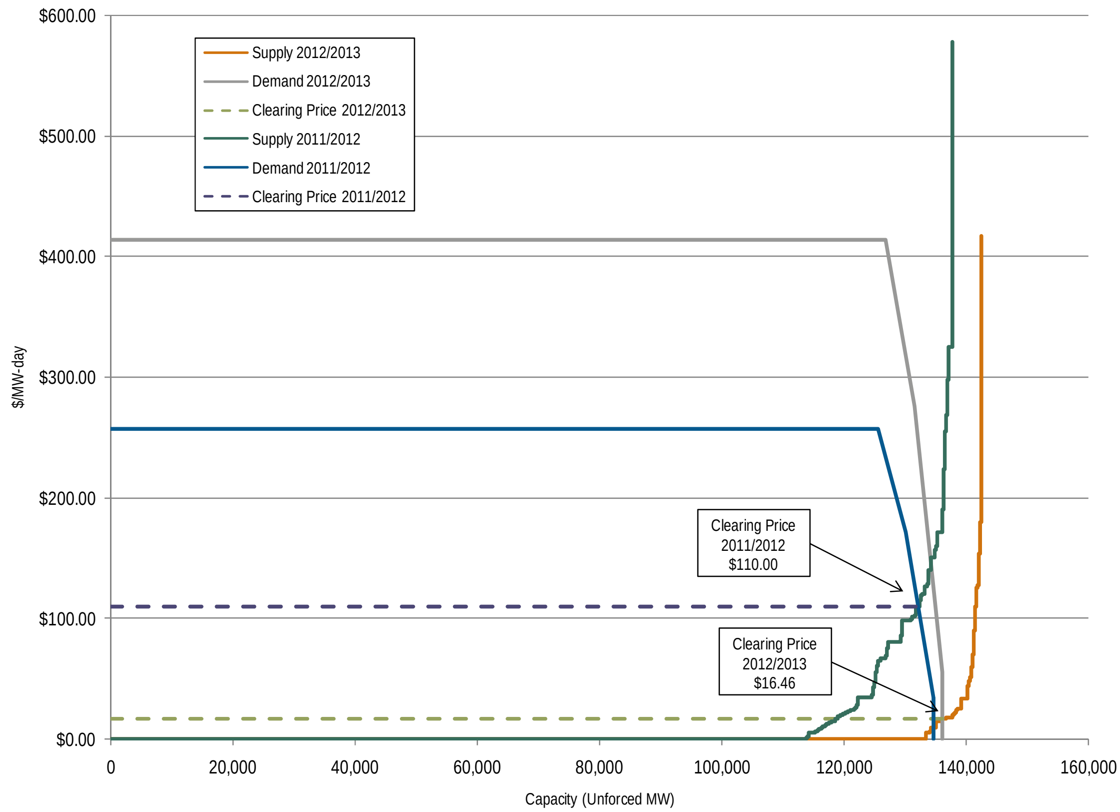
35 The supply curve includes all supply offers at the lower of offer price or offer cap. The demand curve is the RTO reliability requirement less the Short-Term Resource Procurement Target, set at 2.5 percent.

Figure 3 PJM RTO supply/demand curves at reliability requirement: 2012/2013 RPM auction[36]



[36] The supply curve includes all supply offers at the lower of offer price or offer cap. 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, PSEG North and DPL South if the LDAs were cleared at the LDA reliability requirements.

Figure 4 PJM RTO market supply/demand curves: 2011/2012 and 2012/2013 RPM Base Residual Auctions[37]



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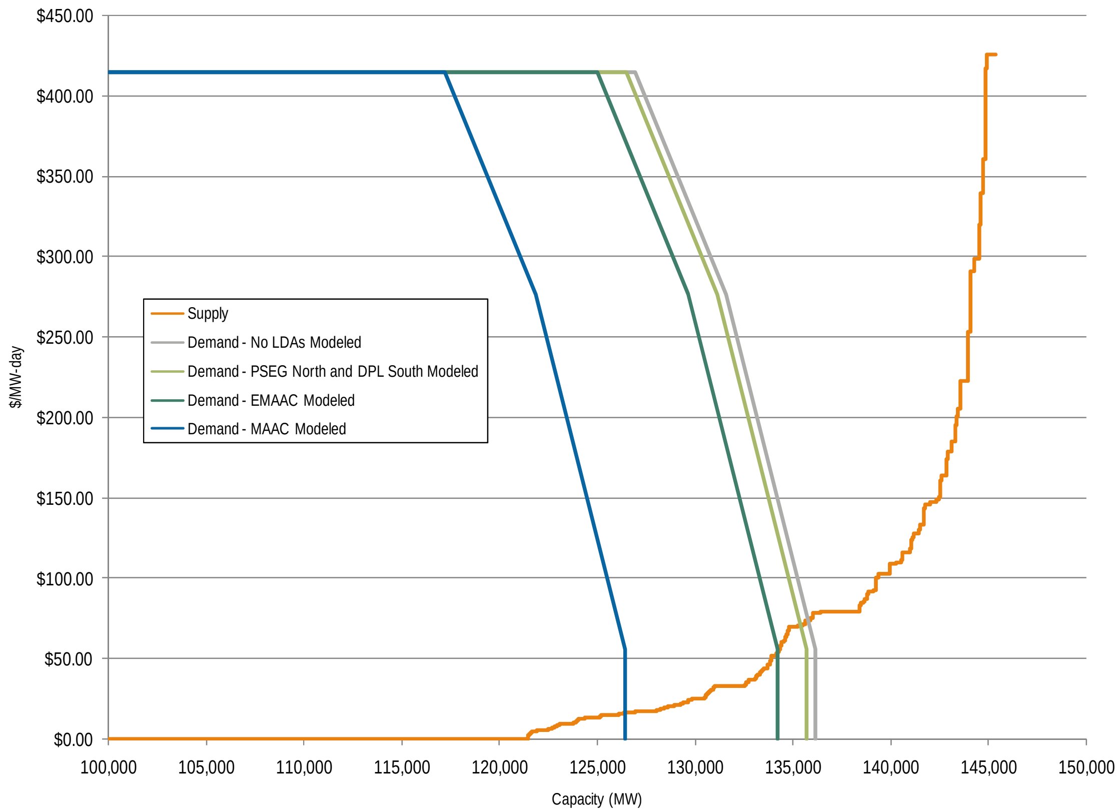
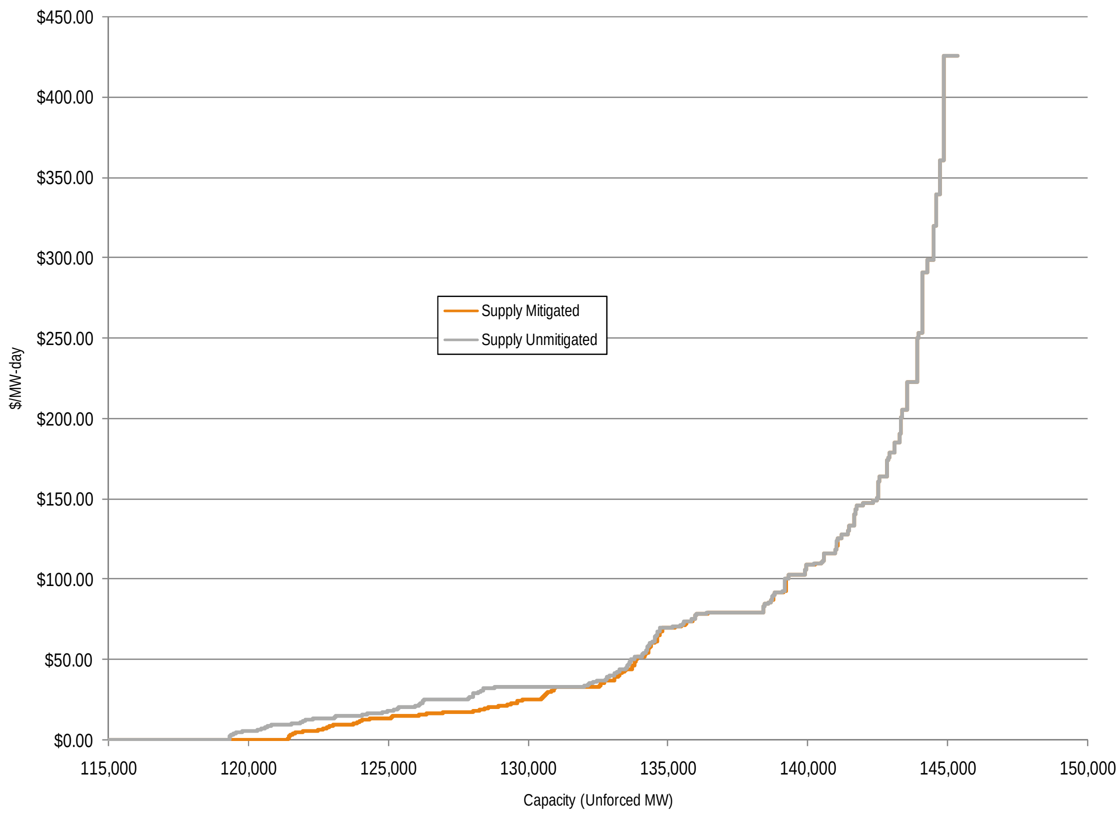
37 The 2011/2012 supply curve includes all supply offers at the lower of offer price or offer cap as there were no modeled LDAs. The 2012/2013 supply curve is shifted to the right by the amount cleared in the LDAs.

Figure 5 RTO market supply/demand curves: Impact of constraints on price formation[38]



38 For ease of viewing, the supply curve is truncated at less than 100,000 MW.

Figure 6 PJM RTO mitigated and unmitigated supply curves: 2012/2013 RPM auction[39]



MAAC

Table 13 shows total MAAC offer data for the 2012/2013 RPM Base Residual Auction. All MW values stated in the MAAC section include all nested LDAs. Total internal MAAC unforced capacity of 69,003.9 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 8, MAAC unforced internal capacity increased by 2,674.2 MW as a result of net generation capacity modifications (-839.4 MW), net DR modifications (3,829.7 MW), and newly offered EE resources (186.9 MW). A decrease of 502.1 MW was due to higher sell offer EFORds, and the remaining decrease of 0.9 MW was due to a lower Load Management UCAP conversion factor compared to the 2011/2012 BRA.

All imports offered into the auction are modeled in the RTO, so MAAC RPM capacity was 69,003.9 MW.[40] For each LDA, the capacity includes the capacity in the LDA and all

[39] For ease of viewing, the supply curve is truncated at less than 115,000 MW.

nested LDAs. Exports were 685.0 MW and 36.4 MW were excused from the RPM must-offer requirement as a result of planned reductions due to environmental regulations (34.5 MW) and other factors (1.9 MW), resulting in available unforced capacity of 68,282.5 MW. After accounting for the above exceptions, all capacity resources in MAAC were offered into the RPM auction.

Of the 65,452.4 MW cleared in MAAC, 55,708.1 MW were cleared in the RTO before MAAC became constrained. Once the constraint was binding, based on the 6,377.0 MW CETL value, only the incremental supply located in MAAC was available to meet the incremental demand in the LDA. Of the 12,574.4 MW of incremental supply, 9,744.3 MW cleared, which resulted in a clearing price of $133.37 per MW-day, as shown in Figure 7. The price was determined by the intersection of the incremental supply and demand curves. The last offer to clear was for a sub-critical coal unit with APIR. The 2,830.1 MW that did not clear had offer prices which exceeded the clearing price. Of the uncleared MW in MAAC, 7.0 MW were EE offers, 305.5 MW were DR offers, and the remaining 2,517.6 MW were generation offers. See Table 9 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 clearing price would have been $102.43 per MW-day, as shown in Figure 8, compared to the actual clearing price of $133.37 per MW-day.

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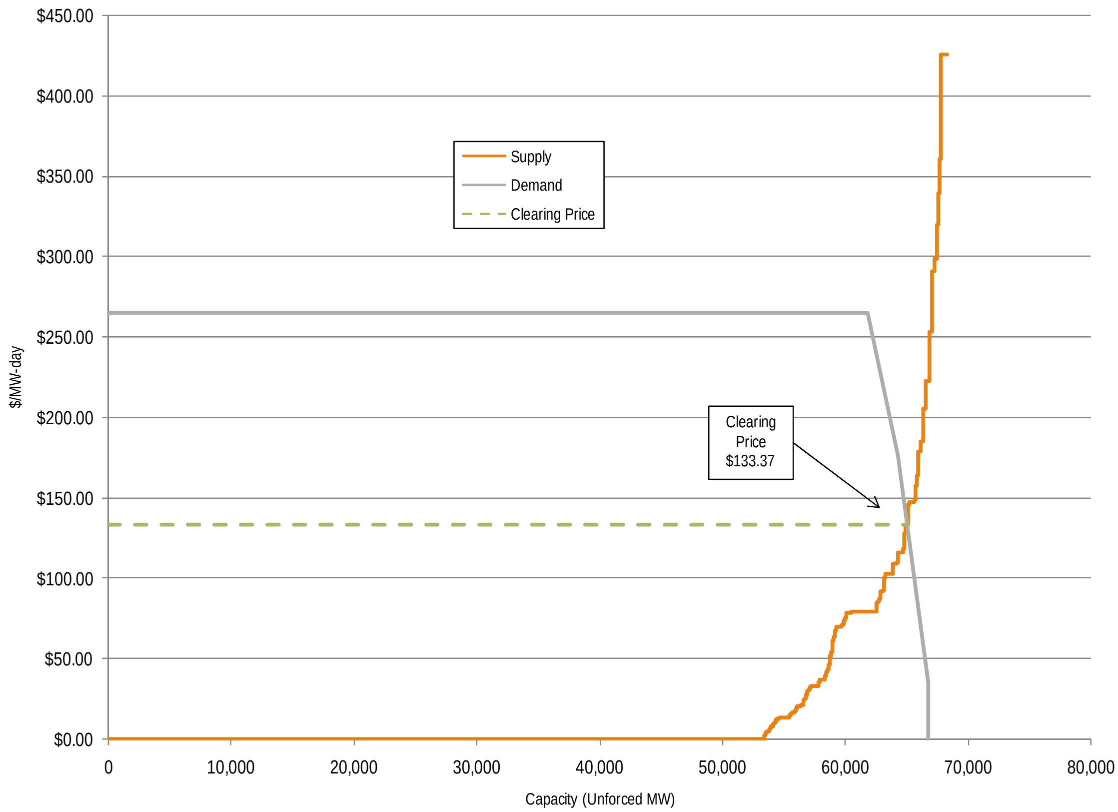
[40] See PJM. "Manual 18: PJM Capacity Market," Revision 6 (Effective June 18, 2009), p. 31, <http://www.pjm.com/documents/~/media/documents/manuals/m18.ashx> (1.25 MB).

Table and Figures for MAAC Section

Table 13 MAAC offer statistics: 2012/2013 RPM Base Residual Auction

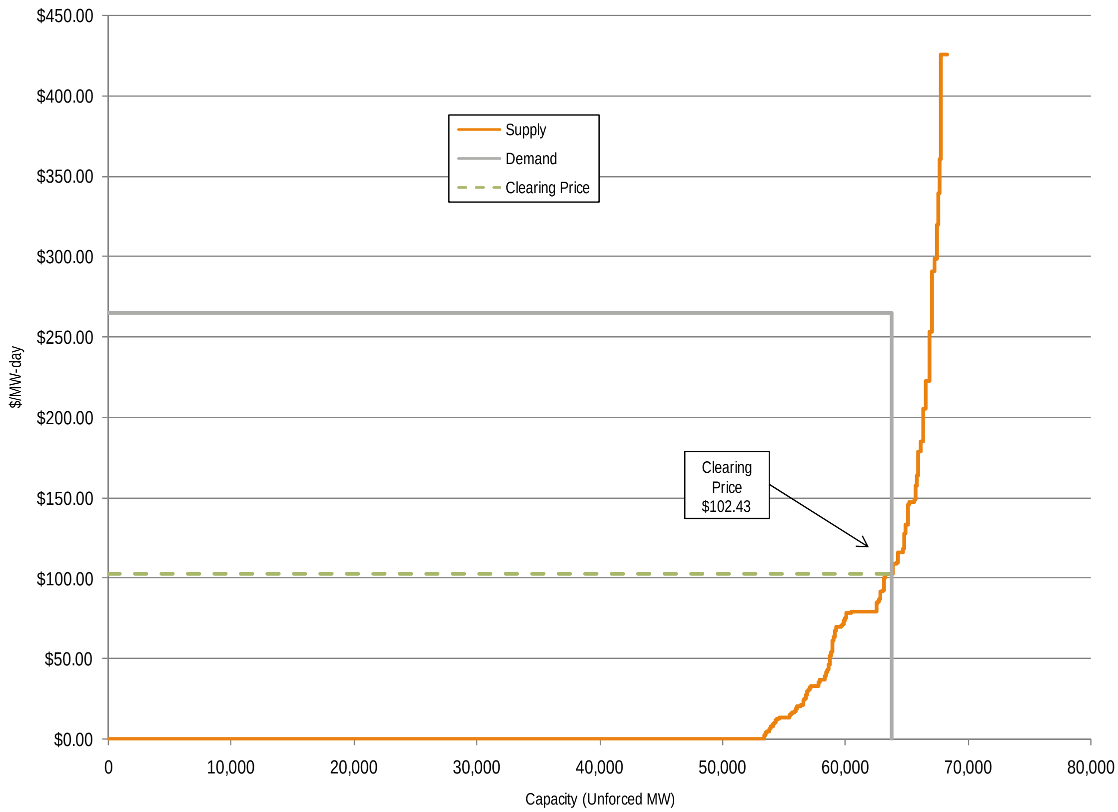
	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Total internal MAAC capacity (gen, DR, and EE)	72,707.2	69,003.9		
Imports	0.0	0.0		
RPM capacity	72,707.2	69,003.9		
Exports	(685.0)	(685.0)		
Excused	(40.2)	(36.4)		
Available	71,982.0	68,282.5	100.0%	100.0%
Generation offered	66,930.8	63,066.4	92.9%	92.3%
DR offered	4,870.0	5,029.2	6.8%	7.4%
EE offered	181.2	186.9	0.3%	0.3%
Total offered	71,982.0	68,282.5	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO	58,237.8	55,708.1	80.9%	81.6%
Cleared in MAAC	10,110.6	9,321.8	14.0%	13.7%
Cleared in EMAAC	18.2	18.6	0.0%	0.0%
Cleared in PSEG North and DPL South	440.5	403.9	0.6%	0.6%
Total cleared	68,807.1	65,452.4	95.6%	95.9%
Uncleared	3,174.9	2,830.1	4.4%	4.1%
Reliability requirement		72,125.0		
Total cleared		65,452.4		
CETL		6,377.0		
Total Resources		71,829.4		
Short-Term Resource Procurement Target		1,673.9		
Net excess/(deficit)		1,378.3		
Resource clearing price ($ per MW-day)		$133.37	A	
Preliminary zonal capacity price ($ per MW-day)		$133.46	B	
Base zonal CTR credit rate ($ per MW-day)		$3.83	C	
Preliminary net load price ($ per MW-day)		$129.63	B-C	

Figure 7 PJM MAAC market supply/demand curves: 2012/2013 RPM Base Residual Auction[41]



[41] The supply curve includes all supply offers at the lower of offer price or offer cap. The demand curve excludes incremental demand which cleared in EMAAC, PSEG North, and DPL South.

Figure 8 PJM MAAC market supply/demand curves at the reliability requirement: 2012/2013 RPM Base Residual Auction[42]



EMAAC

Table 14 shows total EMAAC offer data for the 2012/2013 RPM Base Residual Auction. All MW values stated in the EMAAC section include all nested LDAs. Total internal EMAAC unforced capacity of 33,667.5 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 8, EMAAC unforced internal capacity increased 934.5 MW as a result of net generation capacity modifications (-385.2 MW), net DR modifications (1,480.9 MW), and newly offered EE resources (24.4 MW). A decrease of 185.1 MW was due to higher sell offer EFORds, and the remaining decrease of .5 MW was due to a lower Load Management UCAP conversion factor compared to the 2011/2012 BRA. EMAAC RPM capacity was 33,667.5

42 The supply curve includes all supply offers at the lower of offer price or offer cap. The demand curve is the RTO reliability requirement less the Short-Term Resource Procurement Target and excludes incremental demand that would clear in PSEG North and DPL South if the LDAs were cleared at the LDA reliability requirements.

MW. All imports offered into the auction are modeled in the RTO and exports were 685.0 MW, resulting in available unforced capacity of 32,982.5 MW. All capacity resources in EMAAC were offered into the RPM auction.

Of the 31,080.2 MW cleared in EMAAC, 27,519.9 MW were cleared in the RTO and an additional 3,137.8 MW cleared in MAAC before EMAAC became constrained. Once the constraint was binding, based on the 9,079.0 MW CETL value, only the incremental supply located in EMAAC was available to meet the incremental demand in the LDA. Of the 2,324.8 MW of incremental supply, 422.5 MW cleared, which resulted in a resource clearing price of $139.73 per MW-day, as shown in Figure 9. The price was determined by the intersection of the incremental supply and demand curves. The last offer to clear was for an EE resource. The 1,902.3 MW of uncleared volumes were the result of offer prices which exceeded the clearing price. Of the uncleared MW in EMAAC, 4.4 MW were EE offers, 148.9 MW were DR offers, and the remaining 1,749.0 MW were generation offers. See Table **9** for more details.

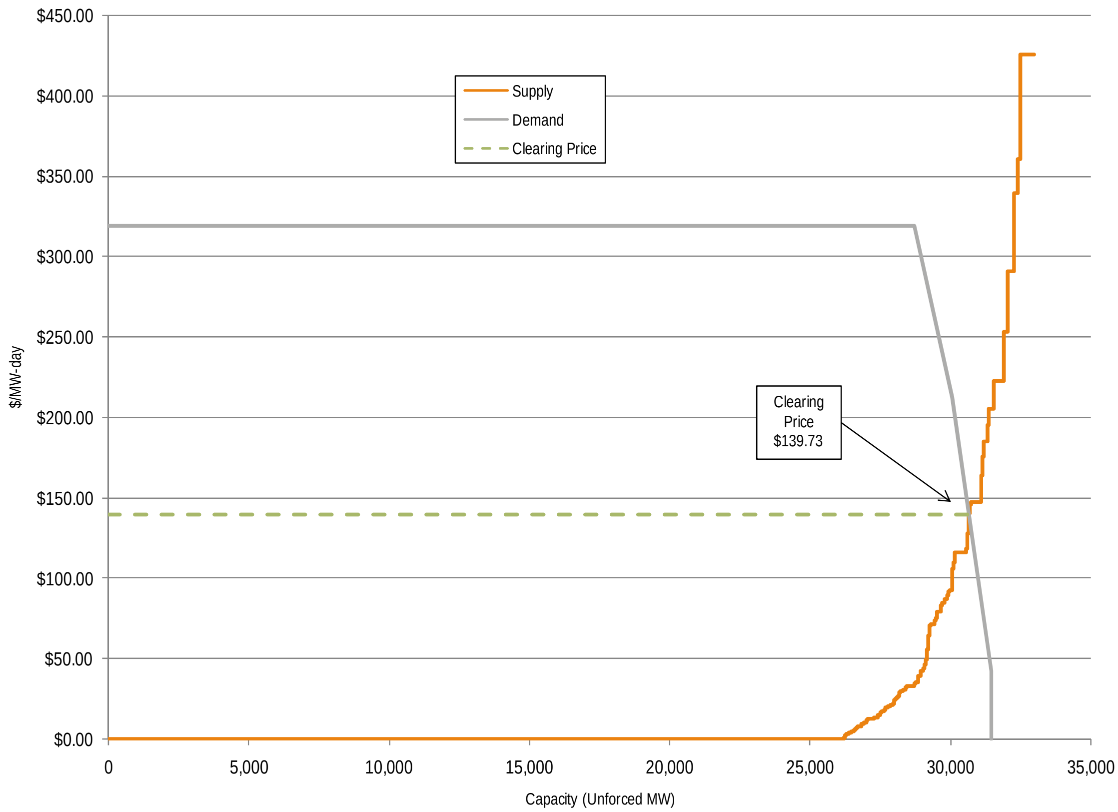
If the demand curve had been vertical at the reliability requirement less the short-term resource procurement target with the same maximum price set at 1.5 times net CONE and given the same LDA modeling, EMAAC would not have had a binding constraint and would have cleared at the MAAC clearing price at the reliability requirement of $102.43 per MW-day, compared to the actual EMAAC clearing price of $139.73 per MW-day.

Table and Figures for EMAAC Section

Table 14 EMAAC offer statistics: 2012/2013 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Total internal EMAAC capacity (gen, DR, and EE)	35,479.9	33,667.5		
Imports	0.0	0.0		
RPM capacity	35,479.9	33,667.5		
Exports	(685.0)	(685.0)		
Excused	0.0	0.0		
Available	34,794.9	32,982.5	100.0%	100.0%
Generation offered	33,040.3	31,170.8	94.9%	94.5%
DR offered	1,730.8	1,787.3	5.0%	5.4%
EE offered	23.8	24.4	0.1%	0.1%
Total offered	34,794.9	32,982.5	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO	28,566.0	27,519.9	82.1%	83.5%
Cleared in MAAC	3,584.5	3,137.8	10.3%	9.5%
Cleared in EMAAC	18.2	18.6	0.1%	0.1%
Cleared in PSEG North and DPL South	440.5	403.9	1.3%	1.2%
Total cleared	32,609.2	31,080.2	93.7%	94.2%
Uncleared	2,185.7	1,902.3	6.3%	5.8%
Reliability requirement		40,145.0		
Total cleared		31,080.2		
CETL		9,079.0		
Total Resources		40,159.2		
Short-Term Resource Procurement Target		922.8		
Net excess/(deficit)		937.0		
Resource clearing price ($ per MW-day)		$139.73	A	
Preliminary zonal capacity price ($ per MW-day)		$139.82	B	
Base zonal CTR credit rate ($ per MW-day)		$4.64	C	
Preliminary net load price ($ per MW-day)		$135.18	B-C	

Figure 9 PJM EMAAC market supply/demand curves: 2012/2013 RPM Base Residual Auction[43]



PSEG North

Table 15 shows total PSEG North offer data for the 2012/2013 RPM Base Residual Auction. Total internal PSEG North unforced capacity of 3,745.3 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 8, PSEG North unforced internal capacity decreased 422.2 MW as a result of net generation capacity modifications (-509.0 MW), net DR modifications (67.6 MW), and the newly offered EE resource (0.9 MW). An increase of 18.3 MW was due to lower sell offer EFORds.

The 440.5 net decrease in UCAP was the result of retirements (345.0 MW), derates (48.2 MW), unit modeling (158.1 MW), offset by uprates to planned generators (42.3 MW), new DR resources (67.6 MW), and new EE resources (0.9 MW). All imports offered into

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43 The supply curve includes all supply offers at the lower of offer price or offer cap. The demand curve excludes incremental demand which cleared in PSEG North and DPL South.

the auction are modeled in the RTO, so RPM capacity was 3,745.3 MW. There were no exports from PSEG North or excused MW, so the available capacity in PSEG North was 3,745.3 MW. All capacity resources in PSEG North were offered into the RPM auction.

Of the 3,521.9 MW cleared in PSEG North, 2,895.6 MW were cleared in the RTO and 517.4 MW cleared in MAAC before PSEG North became constrained. Once the constraint was binding, based on the 2,755.0 MW CETL value, only the incremental supply located in PSEG North was available to meet the incremental demand in the LDA. Of the 332.3 MW of incremental supply, 108.9 MW cleared, which resulted in a resource clearing price of $185.00 per MW-day, as shown in Figure 10. The price was determined by the intersection of the incremental supply and demand curves. The last offer to clear was for an uncapped new CT unit. The 223.4 MW of uncleared capacity were the result of offer prices which exceeded the clearing price, all of which were generation offers. See Table **9** 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 $185.00 per MW-day, as shown in Figure 11.

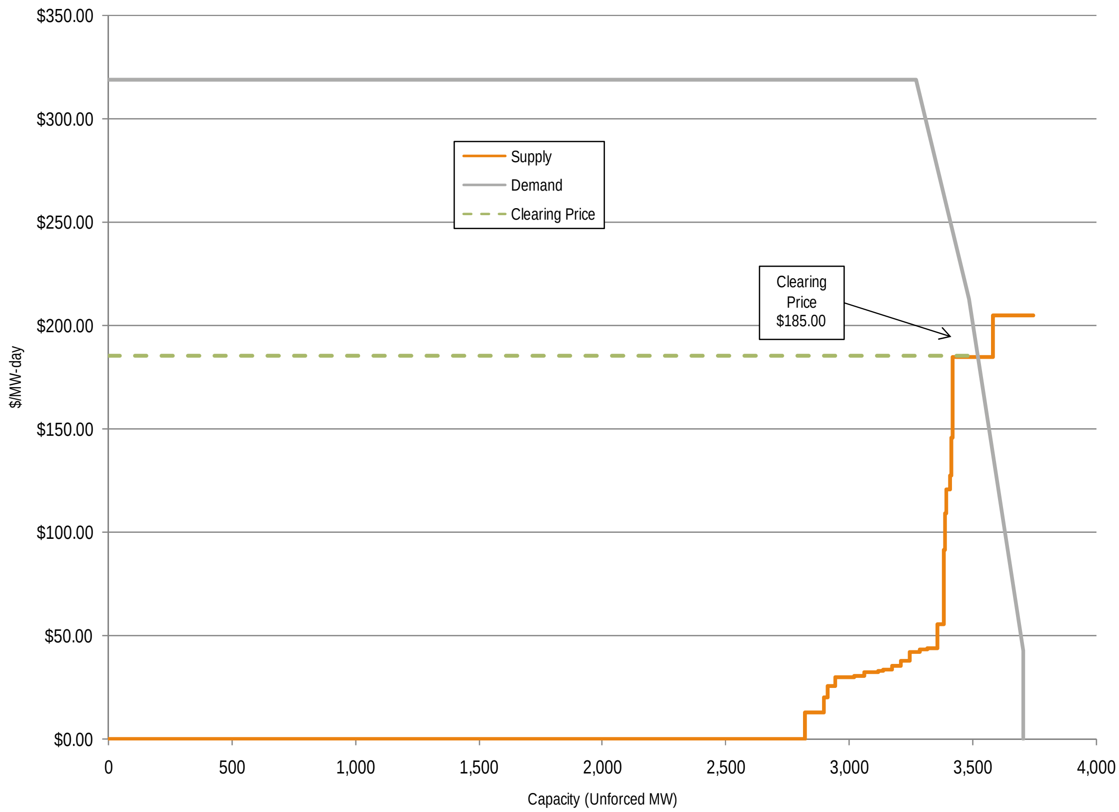
Table and Figures for PSEG North Section

Table 15 PSEG North offer statistics: 2012/2013 RPM Base Residual Auction[44]

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Total internal PSEG North capacity (gen, DR, and EE)	4,121.3	3,745.3		
Imports	0.0	0.0		
RPM capacity	4,121.3	3,745.3		
Exports	0.0	0.0		
Excused	0.0	0.0		
Available	4,121.3	3,745.3	100.0%	100.0%
Generation offered	4,055.0	3,676.8	98.4%	98.2%
DR offered	65.4	67.6	1.6%	1.8%
EE offered	0.9	0.9	0.0%	0.0%
Total offered	4,121.3	3,745.3	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO	3,129.9	2,895.6	75.9%	77.3%
Cleared in MAAC	629.0	517.4	15.3%	13.8%
Cleared in EMAAC	0.0	0.0	0.0%	0.0%
Cleared in LDA	118.2	108.9	2.9%	2.9%
Total cleared	3,877.1	3,521.9	94.1%	94.0%
Uncleared	244.2	223.4	5.9%	6.0%
Reliability requirement		6,324.0		
Total cleared		3,521.9		
CETL		2,755.0		
Total Resources		6,276.9		
Short-Term Resource Procurement Target		136.8		
Net excess/(deficit)		89.7		
Resource clearing price ($ per MW-day)		$185.00	A	
Preliminary zonal capacity price ($ per MW-day)		$162.87	B	
Base zonal CTR credit rate ($ per MW-day)		$13.22	C	
Preliminary net load price ($ per MW-day)		$149.65	B-C	

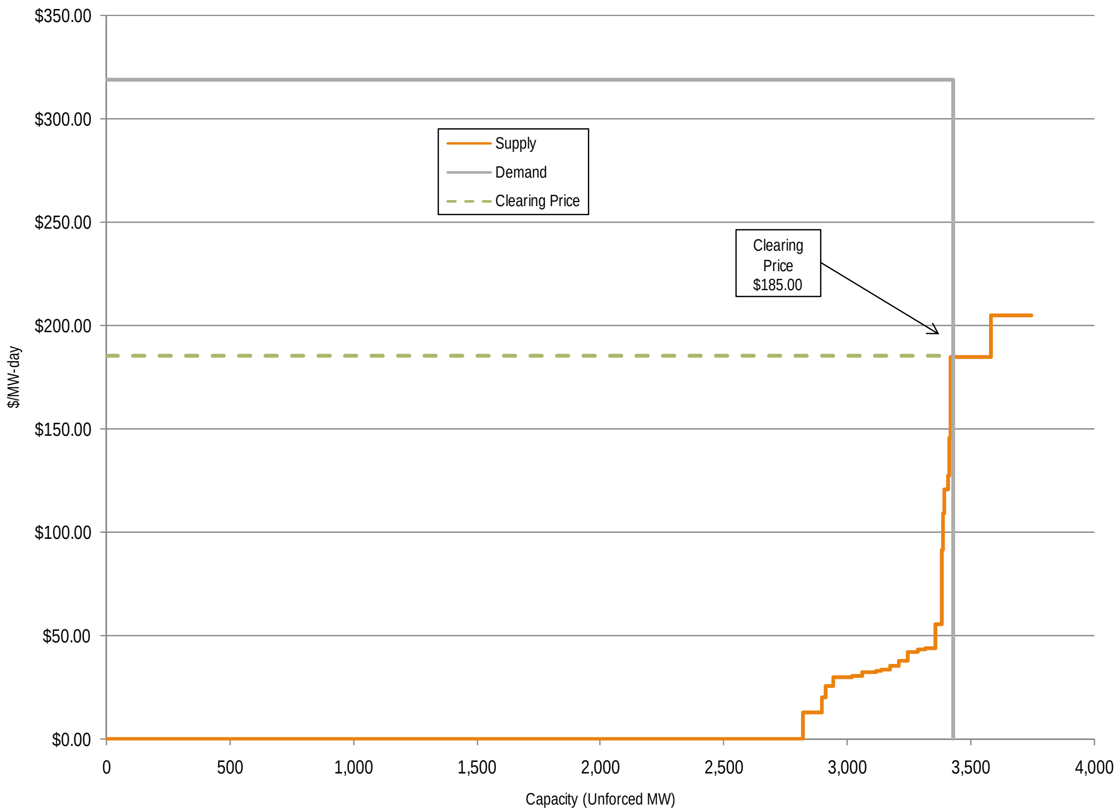
44 There is no separate zonal capacity price or CTR credit rate for PS North as the PS North LDA is completely contained within the PS Zone.

Figure 10 PJM PSEG North market supply/demand curves: 2012/2013 RPM Base Residual Auction[45]



45 The supply curve includes all supply offers at the lower of offer price or offer cap.

Figure 11 PJM PSEG North market supply/demand curves at reliability requirement: 2012/2013 RPM Base Residual Auction[46]



DPL South

Table 16 shows total DPL South offer data for the 2012/2013 RPM Base Residual Auction. Total internal DPL South unforced capacity of 1,498.9 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 8, DPL South unforced internal capacity increased 38.6 MW as a result of net generation capacity modifications (-31.8 MW) and net DR modifications (64.6 MW). An increase of 5.8 MW was due to lower sell offer EFORds.

All imports offered into the auction are modeled in the RTO, so RPM capacity was 1,498.9 MW. There were no exports from DPL South and no excused MW, so the

46 The supply curve includes all supply offers at the lower of offer price or offer cap. The demand curve is the RTO reliability requirement less the Short-Term Resource Procurement Target.

available capacity in DPL South was 1,498.9 MW. All capacity resources in DPL South were offered into the RPM auction.

Of the 1,241.5 MW cleared in DPL South, 892.7 MW were cleared in the RTO and an additional 53.8 MW cleared in MAAC before DPL South became constrained. Once the constraint was binding, based on the 1,746.0 MW CETL value, only the incremental supply located in DPL South was available to meet the incremental demand in the LDA. Of the 552.4 MW of incremental supply, 295.0 MW cleared, which resulted in a resource clearing price of $222.30 per MW-day, as shown in Figure 12. The price was determined by the intersection of the incremental supply and demand curves. The last offer to clear was for a sub-critical coal unit with APIR. The 257.4 MW of uncleared capacity were the result of offer prices which exceeded the clearing price, all of which were generation offers. See Table **9** 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 $222.30 per MW-day, as shown in Figure 13.

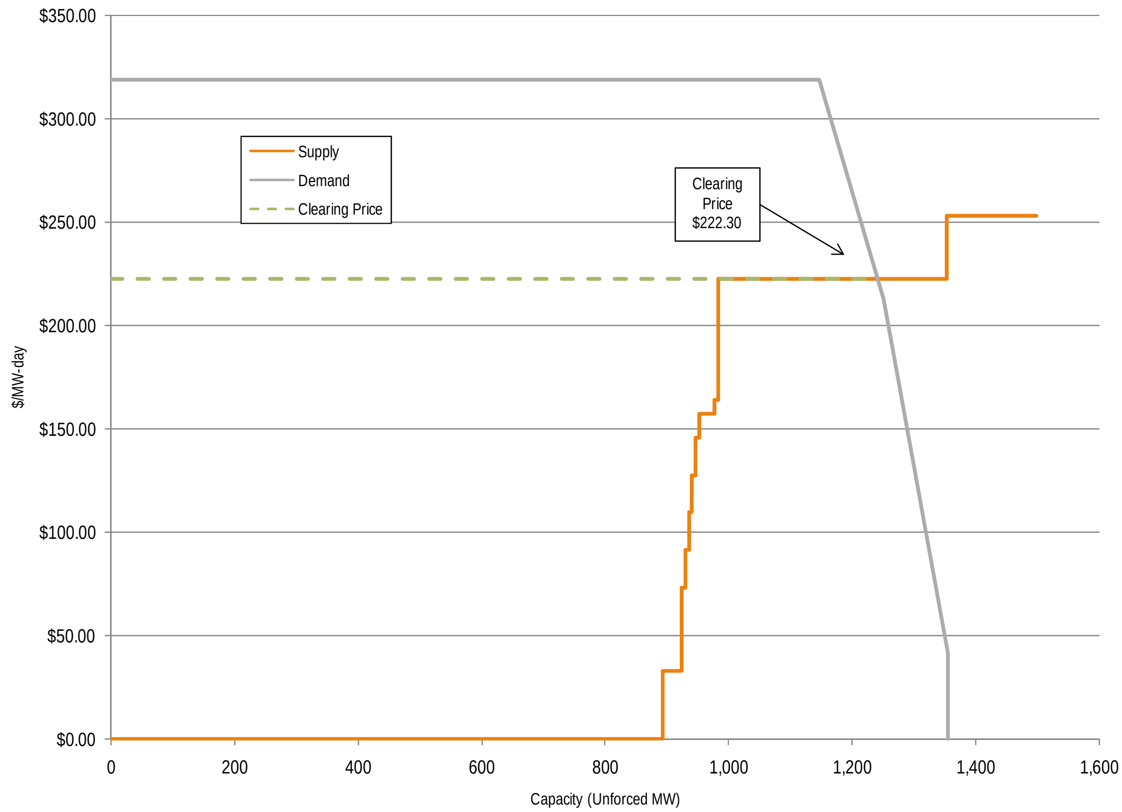
Table and Figures for DPL South Section

Table 16 DPL South offer statistics: 2012/2013 RPM Base Residual Auction[47]

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Total internal DPL South capacity (gen, DR, and EE)	1,582.5	1,498.9		
Imports	0.0	0.0		
RPM capacity	1,582.5	1,498.9		
Exports	0.0	0.0		
Excused	0.0	0.0		
Available	1,582.5	1,498.9	100.0%	100.0%
Generation offered	1,520.0	1,434.3	96.1%	95.7%
DR offered	62.5	64.6	3.9%	4.3%
EE offered	0.0	0.0	0.0%	0.0%
Total offered	1,582.5	1,498.9	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO	923.9	892.7	58.3%	59.5%
Cleared in MAAC	52.1	53.8	3.3%	3.6%
Cleared in EMAAC	0.0	0.0	0.0%	0.0%
Cleared in LDA	322.3	295.0	20.4%	19.7%
Total cleared	1,298.3	1,241.5	82.0%	82.8%
Uncleared	284.2	257.4	18.0%	17.2%
Reliability requirement		3,035.0		
Total cleared		1,241.5		
CETL		1,746.0		
Total Resources		2,987.5		
Short-Term Resource Procurement Target		64.0		
Net excess/(deficit)		16.5		
Resource clearing price ($ per MW-day)		$222.30	A	
Preliminary zonal capacity price ($ per MW-day)		$169.63	B	
Base zonal CTR credit rate ($ per MW-day)		$6.64	C	
Preliminary net load price ($ per MW-day)		$162.99	B-C	

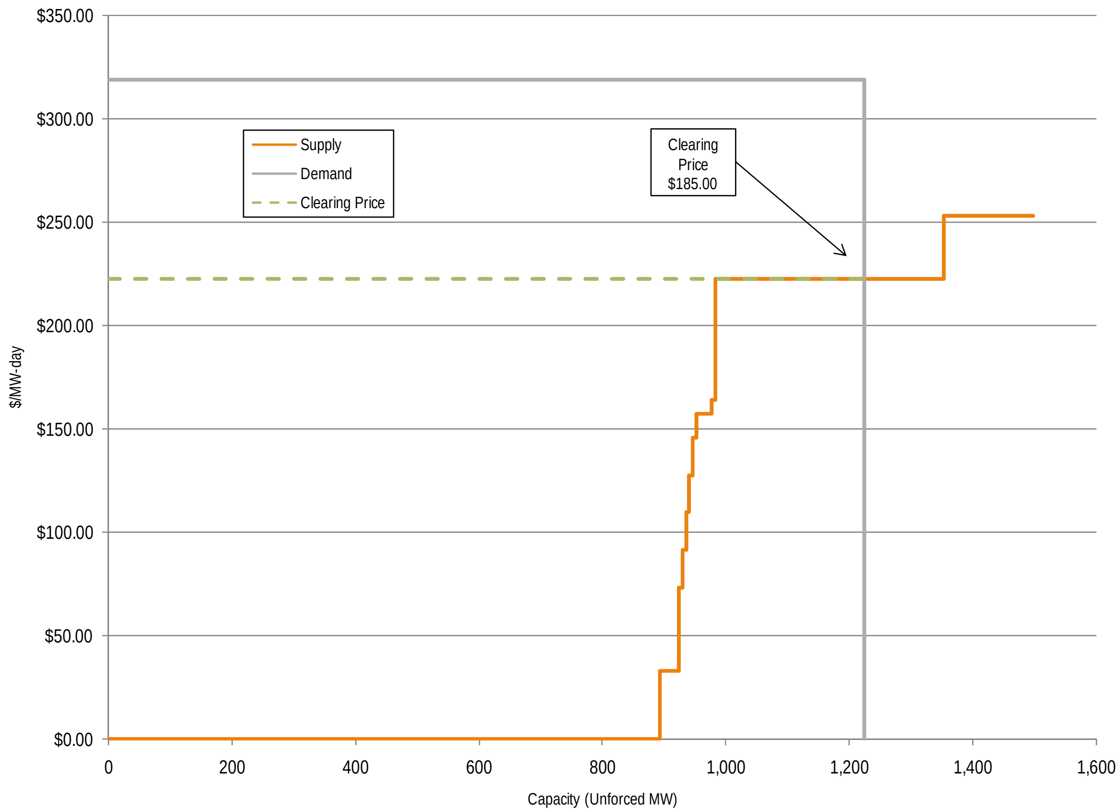
47 There is no separate zonal capacity price or CTR credit rate for DPL South as the DPL South LDA is completely contained within the DPL Zone.

Figure 12 PJM DPL South market supply/demand curves: 2012/2013 RPM Base Residual Auction[48]



48 The supply curve includes all supply offers at the lower of offer price or offer cap.

Figure 13 PJM DPL South market supply/demand curves at reliability requirement: 2012/2013 RPM Base Residual Auction[49]



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. The LM program introduced two RPM-related products:

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

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49 The supply curve includes all supply offers at the lower of offer price or offer cap. The demand curve is the RTO reliability requirement less the Short-Term Resource Procurement Target.

- **ILR –** Capacity load resource that is not offered into the RPM auction, but receives the final zonal ILR price determined after the close of the auction.

Beginning in the 2012/2013 delivery year, the load management product ILR was eliminated.

Another change beginning with the 2012/2013 delivery year was the addition of the Energy Efficiency (EE) resource type eligible to be offered in RPM auctions. 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.[50]

As shown in Table 17, DR offers increased 8,195.2 MW from 1,652.4 MW in the 2011/2012 auction, an increase of 6,542.8 or about 400 percent.

Table 17 DR and EE statistics[51]

	2010/2011 BRA		2011/2012 BRA		2012/2013 BRA	
	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)
DR Planned Offered	935.6	967.9	1,407.3	1,456.0	4,077.9	4,211.5
DR Existing Offered	0.0	0.0	190.0	196.4	5,457.5	5,636.1
Total DR Offered	935.6	967.9	1,597.3	1,652.4	9,535.4	9,847.6
EE Offered					632.3	652.7
DR Planned Cleared	908.0	939.0	1,129.5	1,168.5	1,366.6	1,411.1
DR Existing Cleared	0.0	0.0	190.0	196.4	5,457.5	5,636.1
Total DR Cleared	908.0	939.0	1,319.5	1,364.9	6,824.1	7,047.2
EE Cleared					551.3	568.9

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

51 DR planned total includes only those MW that were planned and offered at non-zero sell offer prices; it does not include planned DR MW that were offered at $0 per MW-day.

DR Analysis

Market Power Mitigation of DR

The market power mitigation rules, as applied to DR resources, had an impact on the outcome of the auction. The price impact was relatively small, but the MW impact was significant. Under the existing rules, PJM used mitigated offers for all existing DR resources in clearing the auction. As shown in Table 18, if existing DR resources had not been mitigated, the RTO clearing price would have been $17.30 per MW-day, rather than $16.46. In addition, 768.3 MW of DR would not have cleared in the RTO, and 768.3 additional MW of generation resources would have cleared. The LDA clearing prices and quantities would have remained the same.

Reduction in Reliability Requirement

PJM implemented a 2.5 percent reduction in the reliability requirement for the 2012/2013 BRA. This was termed the short-term resource procurement target. This rule change had an impact on the results of the auction. As shown in Table 19, if existing DR resources had not been mitigated and the reliability requirement had not been reduced by 2.5 percent, the results would have changed as follows:

- PSEG North would not have constrained;

- DPL South would have cleared, unchanged, at $222.30 per MW-day, but the quantity cleared would have been 1,305.5 MW compared to the actual clearing quantity of 1,241.5 MW;

- EMAAC would have cleared at $185.00 per MW-day, and the quantity cleared in EMAAC would have been 31,635.0 MW compared to the actual clearing price of $139.73 per MW-day and the actual clearing quantity of 31,080.2 MW;

- MAAC would have cleared at $175.00 per MW-day, and the quantity cleared would have been 66,394.0 MW compared to the actual clearing price of $133.37 per MW-day and the actual clearing quantity of 65,452.4 MW;

- RTO would have cleared at $30.00 per MW-day, and the total quantity cleared in the RTO would have been 139,486.8 MW compared to the actual clearing price of $16.46 per MW-day and the actual clearing quantity of 136,143.5 MW.

Impact of Demand Side Resources

Demand side resources, including both DR and EE, had a significant impact on the outcome of the 2012/2013 BRA. The results of the BRA were analyzed under a range of possible levels of DR 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.

As shown in Table 20, if no DR or EE had been offered into the auction, MAAC would have been the only modeled LDA with a binding constraint. MAAC would have cleared at $264.66 per MW-day, and the cleared quantity would have been 61,823.8 MW. The RTO would have cleared at $178.78 per MW-day, and the total cleared quantity would have been 133,568.2 MW.

If all DR and EE offers had been reduced to one third of the actual offers, for a total of 3,498.2 MW of DR and EE offered, MAAC would have been the only modeled LDA with a binding constraint. MAAC would have cleared at $222.30 per MW-day, and the clearing quantity would have been 63,404.1 MW. The RTO would have cleared at $51.53 per MW-day, and the total RTO cleared quantity would have been 136,143.5 MW. Cleared MW of DR and EE would have been 3,029.0 MW. In comparison, offered DR in the 2011/2012 BRA totaled 1,652.4 MW, and cleared DR totaled 1,364.9 MW as shown in Table 17.

If all DR and EE offers had been reduced to two thirds of the actual offers for a total of 7,002.1 MW of DR and EE offered, MAAC and DPL South would have been the only modeled LDAs with binding constraints. DPL South would have cleared at $222.30 per MW-day, and the clearing quantity would have been 1,241.5 MW. MAAC would have cleared at $178.26 per MW-day, and the total MAAC cleared quantity would have been 64,643.6 MW. The RTO would have cleared at $19.31 per MW-day, and the total RTO cleared quantity would be 136,143.5 MW. Cleared MW of DR and EE would have been 5,242.5 MW.

Tables and Figures for DR Analysis Section

Table 18 DR mitigation impact

	Actual Auction Results				No Mitigation of DR			
LDA	Clearing Prices ($/MW-day)	Cleared UCAP (MW)	Gen Cleared (MW)	DR and EE Cleared (MW)	Clearing Prices ($/MW-day)	Cleared UCAP (MW)	Gen Cleared (MW)	DR and EE Cleared (MW)
DPL South	$222.30	1,241.5	1,176.9	64.6	$222.30	1,241.5	1,176.9	64.6
PSEG North	$185.00	3,521.9	3,453.4	68.5	$185.00	3,521.9	3,453.4	68.5
EMAAC	$139.73	31,080.2	29,421.8	1,658.4	$139.73	31,080.2	29,421.8	1,658.4
MAAC	$133.37	65,452.4	60,548.8	4,903.6	$133.37	65,452.4	60,548.8	4,903.6
RTO	$16.46	136,143.5	128,527.4	7,616.1	$17.30	136,143.5	129,295.7	6,847.8

Table 19 DR mitigation and short-term resource procurement impact

	Actual Auction Results				No Mitigation of DR and Without Short-Term Resource Procurement Reduction			
LDA	Clearing Prices ($/MW-day)	Cleared UCAP (MW)	Gen Cleared (MW)	DR and EE Cleared (MW)	Clearing Prices ($/MW-day)	Cleared UCAP (MW)	Gen Cleared (MW)	DR and EE Cleared (MW)
DPL South	$222.30	1,241.5	1,176.9	64.6	$222.30	1,305.5	1,240.9	64.6
PSEG North	$185.00	3,521.9	3,453.4	68.5	$185.00	3,558.2	3,489.7	68.5
EMAAC	$139.73	31,080.2	29,421.8	1,658.4	$185.00	31,635.0	29,867.7	1,767.3
MAAC	$133.37	65,452.4	60,548.8	4,903.6	$175.00	66,394.0	61,247.9	5,146.1
RTO	$16.46	136,143.5	128,527.4	7,616.1	$30.00	139,486.8	132,344.3	7,142.5

Table 20 DR and EE Offer Impact

	Actual Auction Results		Two Thirds of Actual DR or EE Offers		One Third of Actual DR or EE Offers		No DR or EE Offers	
LDA	Clearing Prices ($/MW-day)	Cleared UCAP (MW)	Clearing Prices ($/MW-day)	Cleared UCAP (MW)	Clearing Prices ($/MW-day)	Cleared UCAP (MW)	Clearing Prices ($/MW-day)	Cleared UCAP (MW)
DPL South	$222.30	1,241.5	$222.30	1,241.5	$222.30	1,307.0	$264.66	1,434.3
PSEG North	$185.00	3,521.9	$178.26	3,396.8	$222.30	3,699.6	$264.66	3,676.8
EMAAC	$139.73	31,080.2	$178.26	30,865.8	$222.30	30,701.3	$264.66	30,248.2
MAAC	$133.37	65,452.4	$178.26	64,643.6	$222.30	63,404.1	$264.66	61,823.8
RTO	$16.46	136,143.5	$19.31	136,143.5	$51.53	136,143.5	$178.78	133,568.2

CETO/CETL

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.[52] 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.[53] Attachment A includes a table listing all the transmission upgrades included in the CETO/CETL modeling.[54]

An LDA with CETL less than 1.15 times CETO is modeled as a constrained LDA in RPM. PJM may establish a constrained LDA even if CETL is more than 1.15 times CETO

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52 See PJM. "Manual 14B: PJM Regional Planning Process, Attachment E: PJM Deliverability Methods," Revision 11 (October 5, 2007), <Hhttp://www.pjm.com/contributions/pjm-manuals/pdf/m14b-redline.pdf >. Manual 14B indicates that all "electrically cohesive load areas" are tested.

53 See PJM. "Manual 18: PJM Capacity Market," Revision 2 (Effective April 1, 2008), p. 18, <Hhttp://www.pjm.com/contributions/pjm-manuals/pdf/m18.pdf> (604 KB).

54 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>

if PJM finds that "such is required to achieve an acceptable level of reliability."[55] Effective 2012/2013, the rules also provide that regardless of the test results, separate VRR curves will be established for any LDA with a locational price adder in one or more of the three immediately preceding BRAs, any LDA that PJM determines in a preliminary analysis is likely to have a locational price adder based on historic offer price levels, and EMAAC, SWMAAC, and MAAC LDAs. A reliability requirement and a variable resource requirement curve are established for each constrained LDA.

Table 21 shows the CETL and CETO values used in the 2012/2013 study.

Table 21 PJM LDA CETL and CETO Values: 2012/2013 RPM Base Residual Auction

	MAAC	EMAAC	SWMAAC	PS	PS NORTH	DPL SOUTH
CETO	5,600.0	7,440.0	5,990.0	6,290.0	2,720.0	1,520.0
CETL	6,377.0	9,079.0	7,400.0	6,356.0	2,755.0	1,746.0

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

Upgrade ID	Description	Transmission Owner
b0347.3	Build new 502 Junction 500kV substation	APS
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