Monitoring
Analytics

Analysis of the 2011/2012 RPM Auction

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Independent Market Monitor for PJM

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Introduction

This report, prepared by Monitoring Analytics, LLC, the Independent Market Monitor for PJM (IMM or MMU), reviews the functioning of the fifth Reliability Pricing Model (RPM) base auction (for the 2011/2012 delivery year) and responds to questions raised by PJM members about that auction. The MMU will prepare a similar report for each RPM auction.

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 the capacity market or 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 (VRR) 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 a competitive outcome means reliance on the market power mitigation rules. Attenuation of those rules will mean that market participants will 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 market offers against that competitive standard.

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 EFORd offer segments, verified clearing prices based on the demand curves and verified that the market structure tests were applied correctly. All participants in the RPM auction failed the market structure tests with the result that offer caps were applied to all sellers. The offer caps are designed to reflect the marginal cost of capacity, the definition of a competitive offer. Based on these facts, the MMU concludes that the results of the 2011-2012 RPM auction were competitive.

The MMU also evaluated whether the application of the CETO/CETL ratio rule prevented locational price differences from occurring in the 2011/2012 base residual auction. Under the tariff, PJM determines, in advance of each BRA, whether defined LDAs may be constrained in the auction. An LDA with a CETL greater than 1.05 times CETO is not permitted to constrain in the auction.[1] The results of the MMU analysis lead to the conclusion that the current CETL to CETO ratio test of 1.05 is too restrictive and prevented significant locational price differences from occurring in the 2011/2012 base residual auction. Those locational price differences would have reflected the locational value of capacity, based on actual supply and demand conditions in the identified LDAs which are in part a function of transmission constraints. It is not clear why any such test is required. If a test is to be applied, it should reflect both physical constraints and the economic fundamentals to ensure that the RPM auction results in price signals that reflect the underlying local capacity market supply and demand conditions.

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 auctions.[2] The purpose of the PMSS is to

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1 PJM Open Access Transmission Tariff (OATT), "Attachment DD," §5.10 (a)(ii)(Sheet No. 582)

2 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).

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 locational deliverability area (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. [3]

An LDA or the regional transmission organization (RTO) Region fails the PMSS if any one of the following three screens is failed: (1) the market share of any capacity resource owner exceeds 20 percent; (2) the Herfindahl-Hirschman Index (HHI) for all capacity resource owners is 1800 or higher; or (3) there are not more than three jointly pivotal suppliers.[4] 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.[5]

Consistent with the requirements of the Tariff, the MMU applied the PMSS two months prior to the 2011-2012 RPM auction. As shown in Table 1, the RTO Region failed the PMSS. The RTO passed the market share and HHI screens, but failed the three pivotal supplier screen.[6] As a result, all capacity resource owners were required to submit ACR data to the MMU for resources for which they intended to submit non-zero sell offers

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

4 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).

5 See PJM Open Access Transmission Tariff (OATT), "Attachment DD: Reliability Pricing Model," Second Revised Sheets No. 610-612 (Effective April 1, 2008). The required data are defined at section 6.7.

6 Only results for the RTO market were relevant for the PMSS based on an oral communication from PJM that PJM did not expect any LDAs to constrain during the 2011/2012 RPM auction due to new transmission being built before the delivery year.

unless certain other conditions were met.[7] No provisional exceptions were granted for the 2011-2012 Auction.

Table 1 Preliminary Market Structure Screen results: 2011-2012

RPM Market	Highest Market Share	HHI	Pivotal Suppliers	Pass/Fail
RTO	18.0%	855	1	Fail

Offer Caps

The defined capacity resource owners were required to submit ACR data to the MMU by six weeks prior to the 2011/2012 RPM auction. If a capacity resource owner failed the market power test for the auction, avoidable costs were used to calculate offer caps for that owner's resources.

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, by submitting an opportunity cost for a possible export, by inputting a defined transition adder or by using permitted combinations of these options. The default ACR values were calculated by the MMU based on available unit data and posted to the PJM Web site in order to provide an

7 See PJM Open Access Transmission Tariff (OATT), "Attachment DD: Reliability Pricing Model," Second Revised Sheet No. 610 (Effective April 1, 2008), section 6.7 (c).

8 See PJM Open Access Transmission Tariff (OATT), "Attachment DD: Reliability Pricing Model," Original Sheet No. 617 (Effective June 1, 2007), section 6.8 (b).

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.

As shown in Table 2, 1,125 generating units submitted offers compared to 1,104 generating units offered in the 2010/2011 RPM auction. The net increase of 21 units consisted of 20 new units (2,203.7 MW), four reactivated units (486.9 MW), three fewer excused units (126.3 MW), and one additional unit imported (663.2 MW), offset by five additional FRR units (64.2 MW) and two retired units (85.8 MW). The new units consisted of 11 new CT units (728.7 MW), four new wind units (75.2 MW), two new steam units (838.0 MW), one new combined cycle unit (556.5 MW), one new diesel unit (4.2 MW) and one new solar unit (1.1 MW).[9] There were 37 demand resources (DR) offered compared to 23 DR resources offered in the 2010/2011 RPM auction.[10]

Unit-specific offer caps were calculated for 145 units (12.9 percent of all generating units offered) including 133 units (11.8 percent) with an Avoidable Project Investment Recovery Rate (APIR) component and 12 units (1.1 percent) without an APIR component. Owners submitted unit-specific cost data and net revenue data for these units and the MMU calculated the unit-specific offer caps based on that data. Offer caps of all kinds were used by 472 units (42.0 percent), of which 301 (26.8 percent) were the default ("proxy") offer caps calculated and posted by the MMU. Of the 1,125 generating units, 20 new units had uncapped offers [11] while the remaining 633 units were price

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

10 Some resources had multiple associated offers, i.e. multiple offer segments.

11 Planned units are subject to mitigation only under specific conditions defined in the tariff. Some of the 20 uncapped planned units submitted zero price offers. See PJM Open Access Transmission Tariff (OATT), "Attachment DD: Reliability Pricing Model," Original Sheet No. 617 (Effective June 1, 2007), section 6.5 (a) ii.

takers, of which the offers for 578 units were zero and the offers for 55 units were set to zero because no data were submitted.

As shown in Table 3, the weighted-averages for units with APIR for ACR ($424.49 per MW-day) and offer caps ($147.77 per MW-day) increased from the 2010/2011 values of $360.27 per MW-day and $110.25 per MW-day, respectively, due to additional capital investments in subcritical/supercritical coal units. The APIR component added $324.58 per MW-day to the ACR value of the APIR units compared to $272.18 per MW-day in 2010/2011.[12,13] The default ACR values include an average APIR of $0.91 per MW-day. The highest APIR for a technology ($560.20 per MW-day) was for subcritical/supercritical coal units. The maximum APIR effect ($523.26 per MW-day) is the maximum amount by which an offer cap was increased by APIR. Offer caps for units without an APIR component, including units for which the default value was selected, increased from $20.33 per MW-day to $47.37 per MW-day as a result of higher submitted opportunity costs.

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

13 The 133 units which had an APIR component submitted $613.8 million for capital projects associated with 8,813.7 MW of UCAP.

Table 2 ACR statistics: 2011/2012 RPM auction

Calculation Type	Number of Units	Percent of Generating Units Offered
Default ACR selected	301	26.8%
ACR data input (APIR)	133	11.8%
ACR data input (non-APIR)	12	1.1%
Opportunity cost input	26	2.3%
Offer caps calculated	472	42.0%
Uncapped new units	20	1.8%
Generator price takers	633	56.2%
Generating units offered	1,125	100.0%
Demand resources offered	37	
Total capacity resources offered	1,162	

Table 3 APIR statistics: 2011/2012 RPM auction[14]

	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	$39.98	$29.96	$72.20	$178.64	$62.54		$76.53
Net revenues	$69.17	$19.73	$17.27	$483.70	$322.78		$183.61
Offer caps	$12.42	$16.87	$62.13	$3.55	$11.50	$182.41	$47.37
APIR units							
ACR	$61.66	$56.28	$307.18	$709.11	$36.03		$424.49
Net revenues	$78.17	$10.35	$82.14	$542.90	$2.06		$286.80
Offer caps	$34.69	$46.18	$225.04	$178.79	$33.97		$147.77
APIR	$11.82	$37.28	$213.50	$560.20	$24.68		$324.58
Maximum APIR effect							$523.26

14 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.

RPM Auction Results

MMU Methodology

The MMU reviewed the following inputs to and results of the 2011/2012 RPM auction: [15]

- **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 2005 through 2007;
- **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, if any were excused;
- **Maximum EFORd –** Verified that the maximum equivalent demand forced outage rate (EFORd) used in base offer segments was the one-year EFORd ending September 30, 2007;
- **EFORd Offer Segment –** Verified that the EFORd offer segments were calculated per the tariff;
- **Clearing Prices –** Verified that the auction clearing prices were accurate, based on submitted offers and the Variable Resource Requirement (VRR) curves;
- **Market Structure Test –** Verified that the market power test was properly defined using the three pivotal supplier (TPS) test, that offer caps were properly applied and that the TPS test results were accurate.

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15 All volumes and prices are in terms of unforced capacity (UCAP), which is calculated as installed capacity (ICAP) times (1-EFORd). The equivalent demand forced outage rate (EFORd) values in this report are the EFORd values used in the 2011/2012 RPM auction.

Market Structure Tests

Only those participants that fail the market power test are subject to offer capping. As shown in Table 4, all participants in the total PJM market failed the TPS test.[16] The result was that offer caps were applied to all sell offers except sell offers for new units. The RTO market includes all supply. In general, constrained LDA markets include the incremental supply inside constrained LDAs which was offered at a price higher than the unconstrained clearing price for the RTO market.

Table 4 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 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.[17]

Table 4 RSI results: 2011/2012 RPM auction

	$RSI_{1\ 1.05}$	RSI_3
RTO	0.85	0.63

16 See the *2007 State of the Market Report*, 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

17 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 *2007 State of the Market Report* (March 11, 2008), Appendix L, "Three Pivotal Supplier Test" for additional discussion.

RTO

Table 5 shows total RTO offer data for the 2011/2012 RPM auction. Total internal RTO unforced capacity increased 851.8 MW (0.5 percent) from 159,030.9 MW in the 2010-2011 RPM auction to 159,882.7 MW as a result of new generation (2,203.7 MW), reactivated units (413.5 MW), capacity upgrades to existing generation and increases in DR, net of derations to existing generation and demand capacity resources.

As shown in Table 6, of the 851.8 MW increase in internal unforced capacity, 123.0 MW (14.4 percent) were net generation capacity modifications (cap mods) and 684.4 MW (80.4 percent) were net DR modifications (DR mods).[18] The remaining increase of 44.4 MW (5.2 percent) was due to lower sell offer EFORds. Total internal RTO unforced capacity includes all generating units and DR that qualified as PJM capacity resources for the 2011/2012 auction, excluding external units PJM internal capacity also includes owners' modifications to installed capacity ratings which are permitted under the PJM Reliability Assurance Agreement (RAA) and associated manuals.[19] Multiple owners submitted both positive and negative capacity modifications. Capmod 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. Of the 3,413.1 MW of derations to existing generation units, 3,009.5 MW were due to the reclassification of Duquesne units from PJM internal units to external units. This reclassification also resulted in an increase in imports. 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.[20]

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

[19] See "Reliability Assurance Agreement among Load-Serving Entities in the PJM Region," (June 1, 2007) (Accessed July 19, 2007) <http://www.pjm.com/documents/ downloads/ agreements/ raa.pdf> (1.92 MB).

[20] See "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," Revision 05 (June 1, 2007), p. 11 <http://www.pjm.com/ contributions/pjm-manuals/pdf/m21.pdf> (228 KB). The manual states "the end of the next planning period."

Otherwise the owner must take an outage, as appropriate, if the owner cannot provide energy consistent with the ICAP of the unit.

After accounting for fixed resource requirement (FRR) committed resources and for imports, RPM capacity was 142,263.1 MW compared to 137,360.7 MW in the 2010/2011 RPM auction.[21] FRR volumes decreased by 381.3 MW and imports increased by 3,669.3 MW, primarily due to the way in which Duquesne was accounted for. RPM capacity was reduced by exports of 3,158.4 MW and 348.8 MW which were excused from the RPM must-offer requirement as a result of planned capacity retirements (275.9 MW), non-utility generator (NUG) ownership questions (36.8 MW), planned reductions due to environmental regulations (33.0 MW), and other factors (3.1 MW).[22] Exports increased 11.0 MW and excused volumes decreased 141.3 MW from the 2010/2011 RPM auction. Subtracting 1,035.6 MW of FRR optional volumes not offered, an increase of 405.1 MW in FRR MW not offered from the 2010/2011 RPM auction, resulted in 137,720.3 MW that were available to be offered into the auction, an increase of 4,627.6 MW.[23] After accounting for the above, all capacity resources were offered into the RPM auction. Total offers included 801.6 MW of EFORd offer segments compared to 1,034.9 MW of EFORd offer segments in the 2010/2011 RPM auction.

The downward sloping demand curve resulted in more capacity clearing in the market than the reliability requirement. As shown in Table 5, the 132,221.5 MW of cleared resources for the entire RTO, which represented an installed reserve margin of 18.1 percent, resulted in net excess of 3,156.6 MW over the reliability requirement of 130,658.7

21 The FRR alternative allows an LSE, subject to certain conditions, to avoid direct participation in the RPM auctions. The LSE is required to submit a FRR capacity plan to satisfy the unforced capacity obligation for all load in its service area.

22 If all of the exports had been offered into the auction at $0.00 per MW-day, the clearing price would have been approximately $98.50 per MW-day.

23 FRR entities are allowed to offer into the RPM auction excess volumes above their FRR quantities, subject to a sales cap amount. The 1,035.6 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 precluded from being offered into the auction.

MW (IRM of 15.5 percent), adjusted for forecast ILR.[24, 25] Net excess increased 2,007.4 MW from the net excess of 1,149.2 MW in the 2010/2011 RPM auction. This increase in net excess was due to the increase in supply, mainly due to new generation, and a decrease in demand, reflected in the decrease in the reliability requirement, due to removal of the Duquesne control zone load from the demand forecast. The interruptible load for reliability (ILR) forecast, excluding FRR demand response, decreased 63.8 MW from 1,657.6 MW in the 2010/2011 auction to 1,593.8 MW. As shown in Figure 1, the downward sloping demand curve resulted in a price of $110.00 per MW-day. If the demand curve had been vertical at the reliability requirement, as shown in Figure 2, the clearing price would have been $80.00 per MW-day.

As shown in Figure 3, the RTO clearing price decreased from $174.29 per MW-day in the 2010/2011 auction to $110.00 per MW-day in the 2011/2012 auction. Offered volumes increased 4,627.6 MW from 133,092.7 MW to 137,720.3 MW while the overall RTO reliability requirement, from which the demand curve is developed, decreased 2,040.1 MW from 132,698.8 MW to 130,658.7 MW.[26] The decrease in the reliability requirement,

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[24] Net excess under RPM is calculated as cleared capacity less the reliability requirement plus ILR. For 2007/2008, certified ILR was used in the calculation. For 2008/2009, 2009/2010 and 2010/2011, forecast ILR less FRR DR is used in the calculation because PJM forecast ILR including FRR DR for the first four base residual auctions. FRR DR is not subtracted in the calculation for the 2011/2012 auction because PJM forecast ILR excluding FRR DR for the 2011/2012 BRA. Net excess calculations for auctions prior to 2010/2011 were originally calculated as cleared capacity less the reliability requirement.

[25] The IRM increased from 15.0 percent to 15.5 percent for the 2010/2011 delivery year.

[26] The demand curve UCAP quantities are based on three points, which are ratios of the installed reserve margin (IRM =15.5 percent) times the reliability requirement, less the forecast RTO ILR obligation. For the three points, the ratios are 1.12/1.15, 1.16/1.15 and 1.20/1.15. For these three points the corresponding demand curve 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. For 2010/2011, CONE was $197.83 per MW-day and E&AS was $36.62 MW-day.

due to the exclusion of the Duquesne control zone from the preliminary forecast peak load, shifted the RTO market demand curve to the left.[27]

Table 7 shows the composition of the offers on the tail portion of the RTO supply curve (Figure 1) from $35.00 per MW-day up to and including the highest offer of $577.51 per MW-day. Offers based on opportunity costs made up 39.8 percent of the offers on this section of the supply curve while oil/gas steam, combustion turbines and coal units made up 48.4 percent of the offers, most including an APIR component. The last offer to clear was for a coal unit with an APIR component.

As shown in Table 5, the preliminary net load price that LSEs will pay is $110.00 per MW-day in the RTO. This value is the preliminary zonal capacity price. The final zonal capacity price will be calculated three months before the delivery year when the resource clearing price is adjusted for differences between the certified ILR for the delivery year and the forecasted RTO ILR obligation.

[27] See "Planning Period Parameters" (May 16, 2008) <http://www.pjm.com/markets/rpm/downloads/20080411-2011-2012-rpm-planning-parameters.XLS> (26.0 KB).

Table 5 RTO offer statistics: 2011/2012 RPM auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Total internal RTO capacity (gen and DR)	169,241.6	159,882.7		
FRR	(25,921.2)	(24,039.6)		
Imports	6,814.2	6,420.0		
RPM capacity	150,134.6	142,263.1		
Exports	(3,389.2)	(3,158.4)		
FRR optional	(1,178.1)	(1,035.6)		
Excused	(401.9)	(348.8)		
Available	145,165.4	137,720.3	100.0%	100.0%
Generation offered	143,568.1	136,067.9	98.9%	98.8%
DR offered	1,597.3	1,652.4	1.1%	1.2%
Total offered	145,165.4	137,720.3	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO	139,123.0	132,221.5	95.8%	96.0%
Cleared in LDAs	0.0	0.0	0.0%	0.0%
Total cleared	139,123.0	132,221.5	95.8%	96.0%
Uncleared in RTO	6,042.4	5,498.8	4.2%	4.0%
Uncleared in LDAs	0.0	0.0	0.0%	0.0%
Total uncleared	6,042.4	5,498.8	4.2%	4.0%
Reliability requirement		130,658.7		
Total cleared		132,221.5		
ILR forecast		1,593.8		
Net excess/(deficit)		3,156.6		
Resource clearing price ($ per MW-day)		$110.00	A	
Preliminary zonal capacity price ($ per MW-day)		$110.00	B	
Base zonal CTR credit rate ($ per MW-day)		$0.00	C	
Preliminary zonal ILR price ($ per MW-day)		$110.00	B-C	
Preliminary net load price ($ per MW-day)		$110.00	B-C	

Table 6 Capacity modifications: 2011/2012 RPM auction[28]

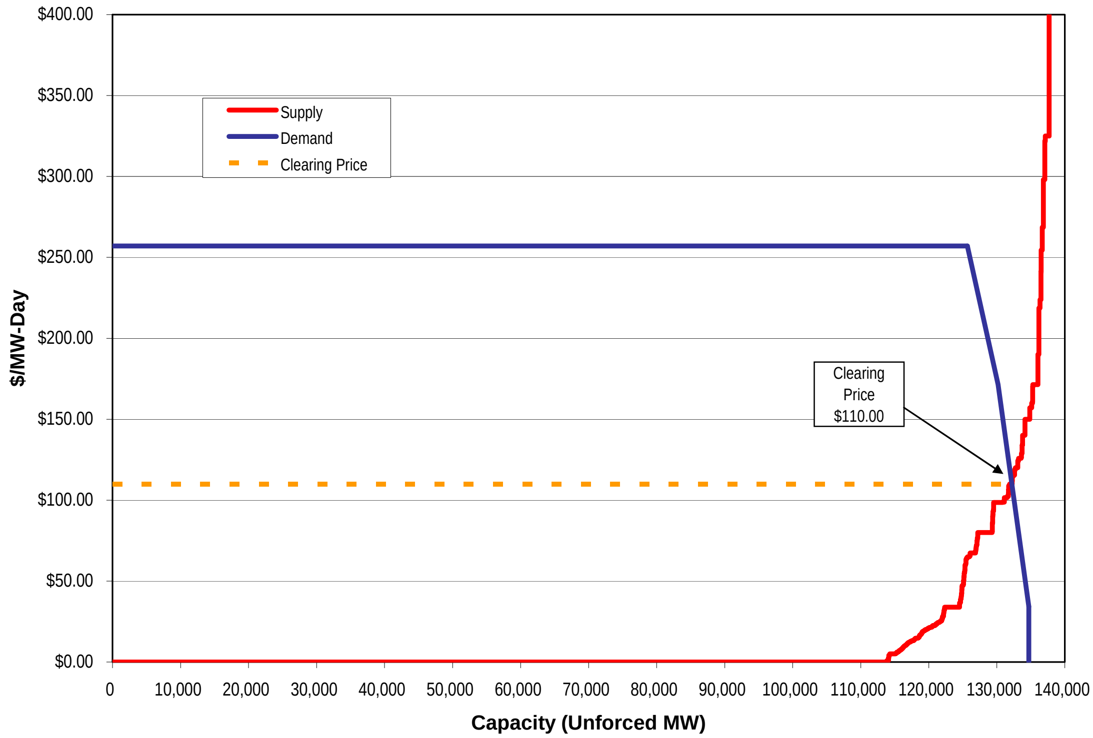
	RTO (MW)	
	ICAP	UCAP
Generation increases	3,730.3	3,536.1
Generation decreases	(3,607.7)	(3,413.1)
Capacity modifications net increase/(decrease)	122.6	123.0
DR increases	1,061.3	1,097.8
DR decreases	(399.6)	(413.4)
DR modifications increase/(decrease)	661.7	684.4
Net capacity/DR modifications increase/(decrease)	784.3	807.4
EFORd effect		44.4
DR effect		0.0
Net Internal Capacity Increase/(Decrease)	784.3	851.8

Table 7 Offers greater than $35.00 on RTO supply curve: 2011/2012 RPM auction

Offer/Technology Type	UCAP (MW)	Percent of Offers
DR	708.9	5.4%
EFORd offer segment	801.6	6.1%
Opportunity costs	5,257.6	39.8%
Oil/gas steam	2,459.4	18.6%
Combustion turbine (CT)	2,178.2	16.5%
Subcritical coal	1,226.0	9.3%
Supercritical coal	527.3	4.0%
Combined cycle	43.5	0.3%
Total	13,202.5	100.0%

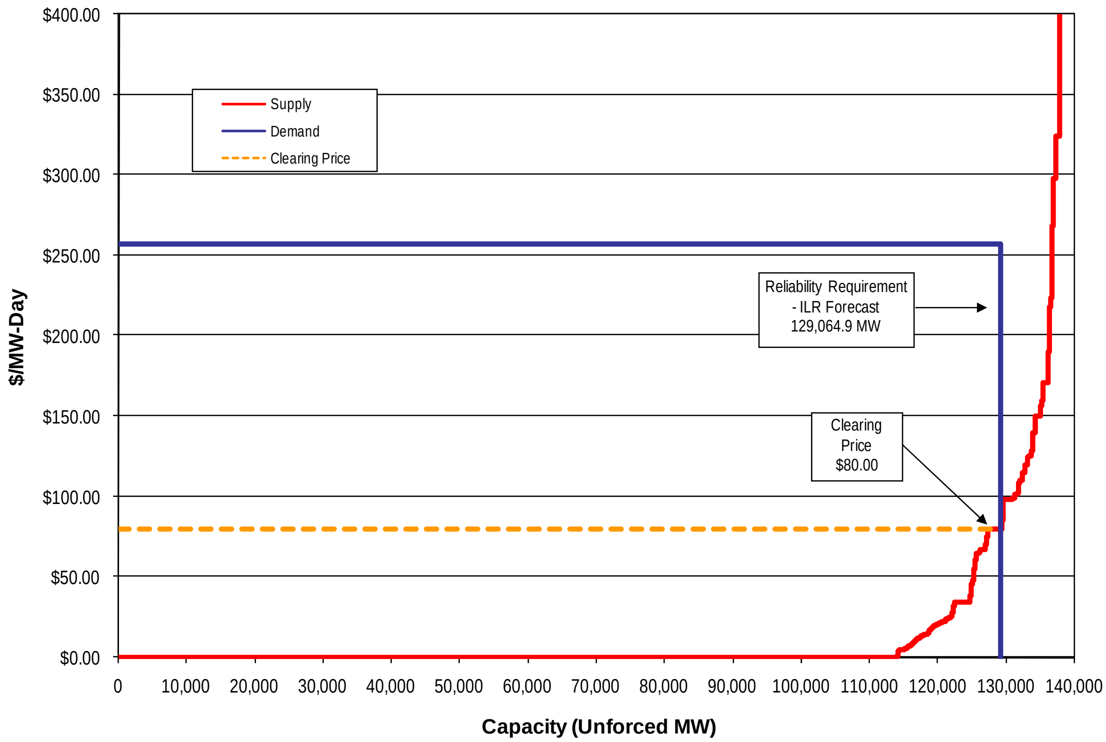
28 Only cap mods and DR mods that had a start date after June 1, 2010 and on or before June 1, 2011 are included.

Figure 1 PJM RTO market supply/demand curves: 2011/2012 RPM auction[29]



29 The supply curve includes all supply offers at the lower of offer price or offer cap. For presentation purposes the supply curve does not show 18.9 MW between $400 and $600.

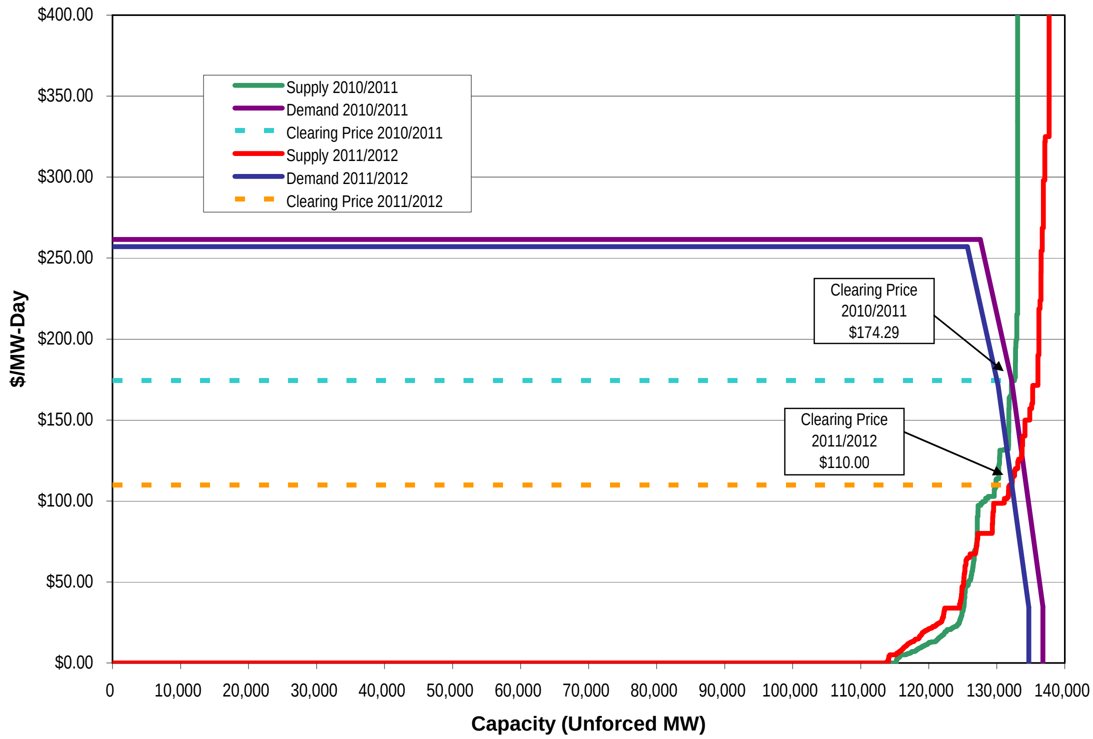
Figure 2 PJM RTO supply/demand curves at reliability requirement: 2011/2012 RPM auction[30, 31]



30 The supply curve includes all supply offers at the lower of offer price or offer cap. For presentation purposes the supply curve does not show 18.9 MW between $400 and $600.

31 The demand curve is the RTO reliability requirement of 130,658.7 MW less the RTO ILR forecast obligation of 1,593.8 MW, or 129,064.9.

Figure 3 PJM RTO market supply/demand curves: 2010/2011 and 2011/2012 RPM auctions[32]



CETO/CETL

Since the ability to import energy and capacity into LDAs may be limited by the existing transmission capability, PJM conducts a load deliverability analysis for each LDA.[33] 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

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32 The supply curve includes all supply offers at the lower of offer price or offer cap. For presentation purposes the supply curve does not show 18.9 MW of 2011/2012 offers between $400 and $600.

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

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 Process (RTEPP).[34]

An LDA with CETL less than 1.05 times CETO is modeled as a constrained LDA in RPM. PJM may establish a constrained LDA even if CETL is more than 1.05 times CETO if PJM finds that "such is required to achieve an acceptable level of reliability."[35] A reliability requirement and a variable resource requirement curve are established for each constrained LDA.

The complete tariff language is:[36]

> For any Delivery Year, the Office of the Interconnection shall establish a separate Variable Resource Requirement Curve for each LDA for which the Capacity Emergency Transfer Limit is less than 1.05 times the Capacity Emergency Transfer Objective, as determined by the Office of the Interconnection in accordance with NERC and Applicable Regional Reliability Council guidelines; provided however that the Office of the

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

35 See PJM Open Access Transmission Tariff (OATT), "Attachment DD: Reliability Pricing Model," Original Sheet No. 584 (Effective June 1, 2007), section 5.10 (a)(ii).

36 See PJM Open Access Transmission Tariff (OATT), "Attachment DD: Reliability Pricing Model," Original Sheet No. 584 (Effective June 1, 2007), section 5.10 (a)(ii).

> Interconnection may establish a separate Variable Resource Requirement Curve for an LDA for which such margin is greater than 105% if it finds that such is required to achieve an acceptable level of reliability consistent with the Reliability Principles and Standards, in which case the Office of the Interconnection shall post such finding, such LDA, and such Variable Resource Requirement Curve on its internet site no later than the March 31 last preceding the Base Residual Auction for such Delivery Year.

Constrained LDAs

PJM determines, in advance of each BRA, whether defined LDAs may be constrained in the auction. For an LDA with CETL less than 1.05 times CETO, PJM must create a separate demand curve (VRR curve) which may result in price separation depending on the relationship between the supply and demand curves. PJM is not required to create a separate demand curve for an LDA with a CETL greater than 1.05 times CETO. In the absence of a separate demand curve, the LDA cannot be constrained in the auction. However, PJM may establish a separate demand curve even if CETL is more than 1.05 times CETO if PJM finds that "such is required to achieve an acceptable level of reliability."[37]

The use of a 1.05 ratio of CETL to CETO creates the potential that an LDA which would be constrained based on actual market economics, will not be allowed to be constrained in the auction. This can occur as a result of the relationship between physical transmission capability and the actual supply curves in each LDA. The situation is analogous to the determination of LMP in the energy market in the presence of transmission constraints. A transmission constraint will not be binding and congestion will not result if the costs of generation on both sides of the constraint are comparable or if the cost of generation on the potentially constrained side is less than the cost of generation on the potentially unconstrained side. Thus in an RPM auction, there could be a situation where the ratio of CETL to CETO is less than 1.05 and the LDA does not have a separate, higher price if the capacity offer prices in the potentially constrained area are comparable to or less than capacity offer prices in the non-constrained area. Alternatively, a transmission constraint will be binding and congestion will result if the

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[37] PJM Open Access Transmission Tariff (OATT), "Attachment DD," §5.10 (a)(ii)(Sheet No. 582)

capacity offer prices on the constrained side are higher than the capacity offer prices on the unconstrained side. The actual occurrence of congestion results from the combined effect of transmission capability, the supply curve and the demand curve for capacity in the LDA. Thus, there could be a situation where the ratio of CETL to CETO is greater than 1.05 and the LDA would have a separate, higher price when calculated based on the economic fundamentals and, in particular, on the capacity offer prices on both sides of the constraint.

This situation occurred in the 2011/2012 BRA. PJM determined that the ratio of CETL to CETO for all LDAs was greater than 1.05 and that there would be no constrained LDAs in the 2011/2012 BRA. The result was to limit the auction outcome to a single clearing price for the entire RTO. However, the MMU analysis shows that MAAC and EMAAC were actually economically constrained and that, if the auction had been cleared absent the application of the CETL to CETO ratio rule, there would have been substantial price separation. The RTO price would have been less than the reported clearing price of $110 and the MAAC and EMAAC prices would have been greater than the reported clearing price of $110.

The prices that would have resulted if price separation had followed the underlying market economics are included in Table 8. The RTO market price would have been $80.00 rather than $110.00. The MAAC price would have been $139.84 rather than $110.00. The SWMAAC price would have been $139.84 rather than $110.00. (SWMAAC is part of MAAC and there were no economically binding constraints between the rest of MAAC and SWMAAC.) The EMAAC price would have been $179.74 rather than $110.00.

These results lead to the conclusion that the current CETL to CETO ratio test of 1.05 is too restrictive and prevented significant locational price differences from occurring in the 2011/2012 base residual auction. Those locational price differences would have reflected the locational value of capacity, based on actual supply and demand conditions in the identified LDAs together with the transmission constraints. It is not clear why any such test is required. If a test is to be applied, it should reflect both physical constraints and the economic fundamentals to ensure that the RPM auction results in price signals that reflect the underlying local capacity market supply and demand conditions.

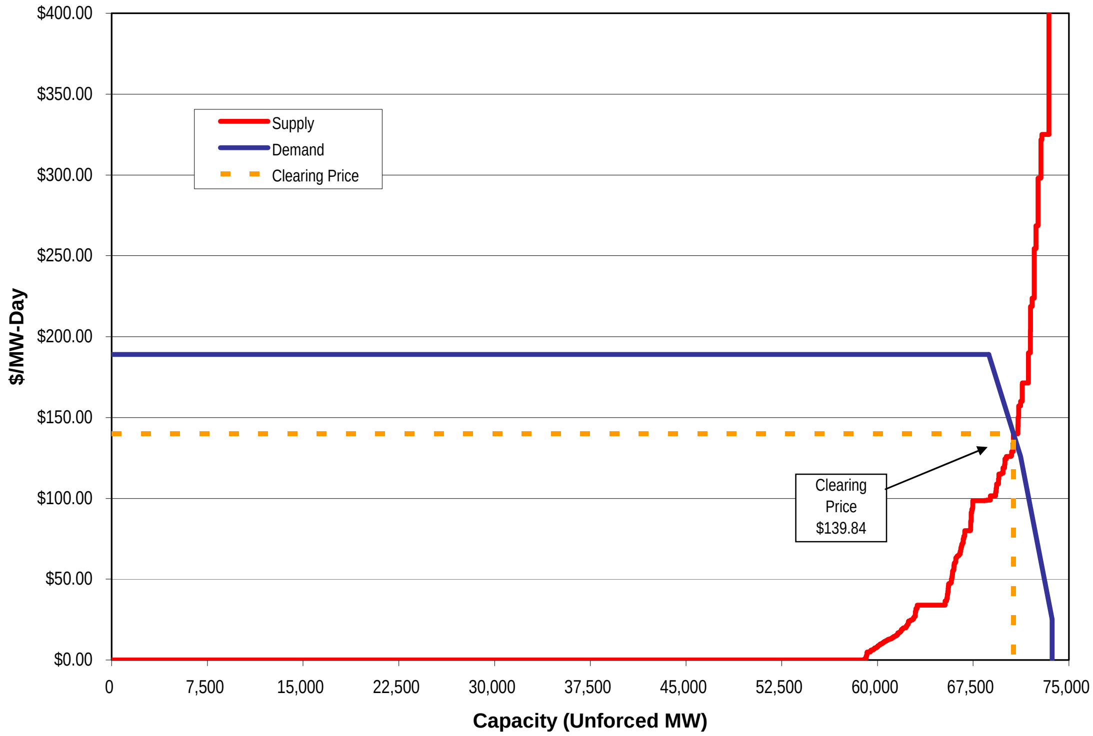
Table 8 Comparison of clearing prices and constrained prices: 2011/2012 RPM auction

	2011/2012 Clearing Prices ($/MW-day)	2011/2012 Constrained ($/MW-day)
RTO	$110.00	$80.00
MAAC	$110.00	$139.84
SWMAAC	$110.00	$139.84
EMAAC	$110.00	$179.74

MAAC

Figure 4 shows the 2011/2012 supply and demand curves for the MAAC (Mid-Atlantic Area Council) LDA and the resultant constrained clearing price and quantity that would have resulted had price separation followed the underlying market fundamentals.

Figure 4 MAAC market constrained supply/demand curves: 2011/2012 RPM auctions[38]



EMAAC

Figure 5 shows the 2011/2012 supply and demand curves for the EMAAC (Eastern Mid-Atlantic Area Council) LDA and the resultant constrained clearing price and quantity that would have resulted had price separation followed the underlying market fundamentals.

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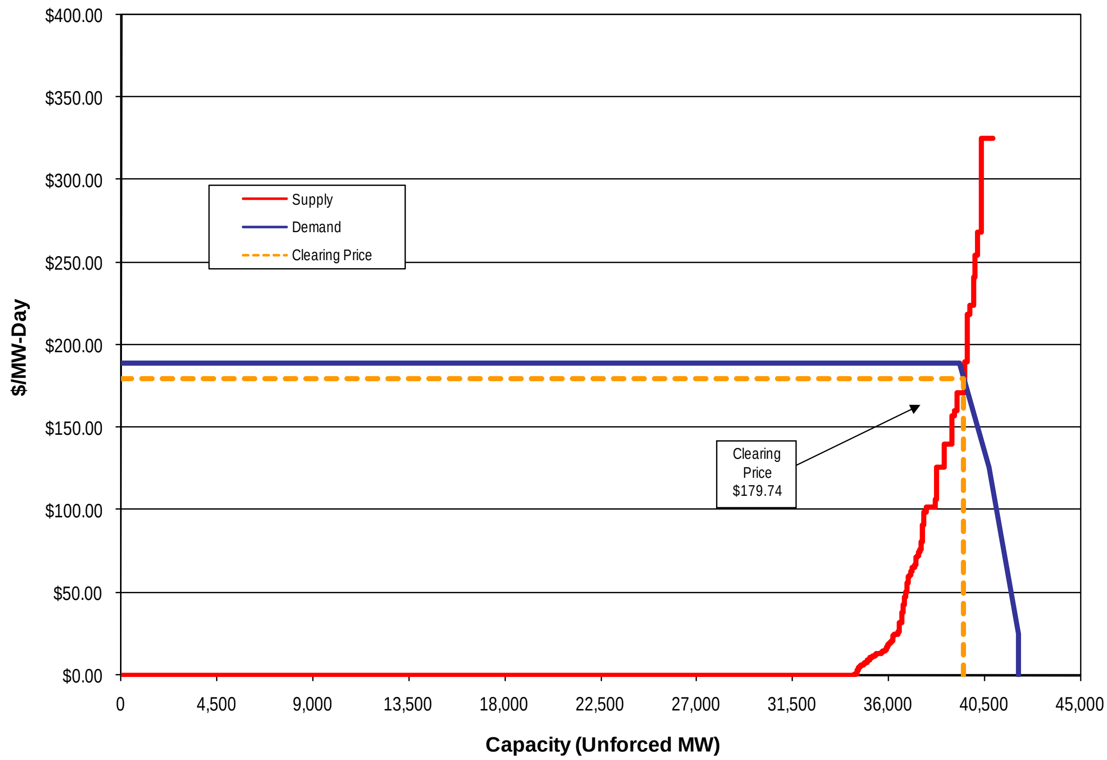
38 The supply curve includes all supply offers at the lower of offer price or offer cap. For presentation purposes the supply curve does not show 1.9 MW of 2011/2012 offers between $400 and $600.

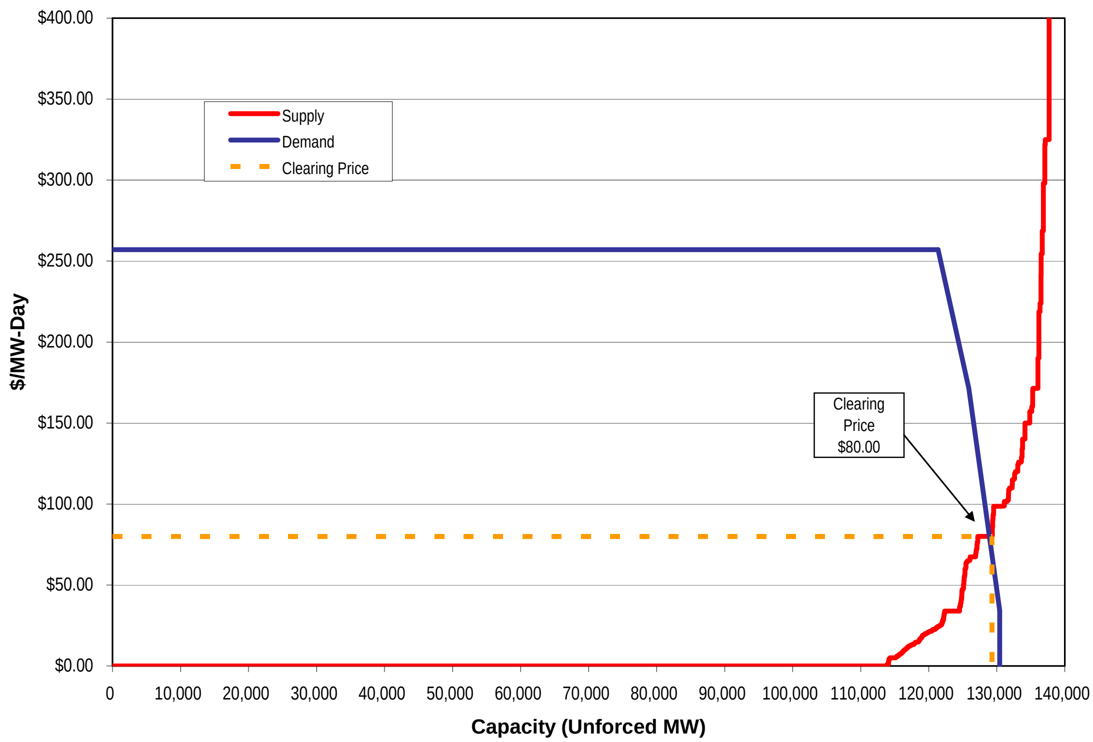
Figure 5 EMAAC market constrained supply/demand curves: 2011/2012 RPM auctions



RTO

Figure 6 shows the 2011/2012 supply and demand curves for the RTO market and the resultant constrained clearing price and quantity that would have resulted had price separation followed the underlying market fundamentals.

Figure 6 RTO market constrained supply/demand curves: 2011/2012 RPM auctions



Load Management (LM)

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, or can they can be offered outside of the auction and receive the final zonal ILR 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

- **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.

As shown in Table 9, the LM program provided 3,246.2 MW, which is a combination of DR offered into the RPM auction and forecast ILR for the 2011/2012 delivery year.[39] DR offers increased 684.5 MW from 967.9 MW in the 2010-2011 auction. Total LM volumes increased 1,569.5 MW over the final ALM MW provided before the implementation of RPM. ILR will be certified three months before the delivery year.

Table 9 Load management statistics: 2011/2012 RPM auction

	RTO UCAP (MW)
DR offered	1,652.4
ILR forecast	1,593.8
Total load management	3,246.2
ALM @ May 31, 2007	1,676.7

There are a number of other differences between PJM's ALM program and the LM program that replaced it.

There is a difference in certification timing. Under the ALM program, customers could be nominated at any time prior to the day that ALM was called upon by PJM. Under RPM, DR must be offered into the auction for the delivery year in which they will participate while ILR resources must be certified by a published deadline which is after the base auction for the delivery year and at least three months prior to the delivery year in which they will participate.

Differences exist in the way compliance and settlement are handled. Under the ALM program, all data was input into eCapacity, and ALM providers received a levelized MW credit for the October-May period which resulted in ALM providers avoiding the purchase of capacity. Under RPM, DR and ILR are certified and event compliance data are submitted in LoadResponse, which is part of PJM's eSuite. Under RPM, DR and ILR settlement rates are set prior to the delivery year and do not change. DR is offered into an RPM base residual auction and receives the auction clearing price while ILR will be certified and receive the final zonal ILR price (see Table 5 for example).

39 The ILR forecast excludes Duquesne-related ILR.