Market Monitoring Unit

Analysis of the
2009 – 2010 RPM Auction

PJM Market Monitoring Unit

February 11, 2008

Introduction

This report, prepared by the PJM Market Monitoring Unit (MMU), reviews the functioning of the third Reliability Pricing Model (RPM) auction (for the 2009-2010 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 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 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 competitive market offers.

The MMU verified the reasonableness of offer data and calculated the derived offer caps based on submitted data, calculated unit net revenues, verified capacity exports, verified the reasons for MW not offered, verified the maximum 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. Based on these facts, the MMU concludes that the results of the 2009-2010 RPM auction were competitive.

Preliminary Market Structure Screen (PMSS)

Under the terms of the PJM Tariff, the MMU is required to apply the preliminary market structure screen (PMSS) prior to RPM auctions.[1] 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 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.[2]

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

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

suppliers.[3] 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.[4]

Consistent with the requirements of the Tariff, the MMU applied the PMSS two months prior to the 2009-2010 RPM auction. As shown in Table 1, all three defined areas failed the PMSS. The RTO Region passed the market share and HHI screens, but failed the three pivotal supplier screen. The Eastern Mid-Atlantic Area Council (EMAAC) LDA, Southwestern Mid-Atlantic Area Council (SWMAAC) LDA and Mid-Atlantic Area Council plus APS (MAAC+APS) failed all three screens.[5] Each of the three areas also failed the two pivotal supplier test and the one pivotal supplier test, using the same market definition applied with the three pivotal supplier test. 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.[6] Specified types of units in areas outside the two constrained LDAs were provisionally exempted from providing such data based on the assumption that these units would not affect the clearing price.[7]

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

4 See PJM Open Access Transmission Tariff (OATT), "Attachment DD: Reliability Pricing Model," First Revised Sheets No. 609-612 (Effective June 20, 2007). The required data are defined at section 6.7.

5 MAAC+APS was a newly constrained LDA for the 2009-2010 auction. It includes but is not limited to the EMAAC and SWMAAC LDAs.

6 See PJM Open Access Transmission Tariff (OATT), "Attachment DD: Reliability Pricing Model," First Revised Sheet No. 610 (Effective June 20, 2007), section 6.7 (c).

7 Attachment A provides the referenced MMU letter regarding provisional exemptions from the data requirement.

Table 1 Preliminary Market Structure Screen results: 2009-2010[8]

RPM Markets	Highest Market Share	HHI	Pivotal Suppliers	Pass/Fail
RTO	18.4%	853	1	Fail
EMAAC	31.3%	2053	1	Fail
SWMAAC	51.1%	4229	1	Fail
MAAC+APS	26.9%	1627	1	Fail

Offer Caps

The defined capacity resource owners were required to submit ACR data to the MMU by six weeks prior to the 2009-2010 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.[9] 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

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8 The RTO includes MAAC+APS, EMAAC and SWMAAC. MAAC+APS includes but is not limited to the EMAAC and SWMAAC LDAs. In the 2009-2010 auction EMAAC was not constrained, so results for it are not shown.

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

possible export, by inputting a 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 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. The transition adder was added to the offer cap, if appropriate, regardless of the offer-cap calculation method.[10]

As shown in Table 2, 1,093 generating units submitted offers as compared to 1,076 generating units offered in the 2008-2009 RPM auction. The increase of 17 units included eight new CT units (380.2 MW), one new diesel unit (7.5 MW) and one new steam unit (49.8 MW) while the remaining increase of seven units was the result of a combination of more units imported, less units exported, a decrease in units excused from offering into the auction and less units removed from the auction under the FRR option.[11] There were 38 DR resources offered compared to 23 DR resources offered in the 2008-2009 RPM auction.[12] Unit-specific offer caps were calculated for 151 units (13.8 percent). 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 550 units (50.3 percent), of which 377 were the default ("proxy") offer caps calculated and posted by the MMU. Of the 1,093 generating units, three new units had uncapped offers while the remaining 540 units were price takers, of which the offers for

10 The transition adder, which is added to the calculated offer cap, is $10.00 per MW-day for delivery years 2007-2008 and 2008-2009 and $7.50 per MW-day for delivery years 2009-2010. It can be applied only up to 3,000 MW of unforced capacity per owner, only in unconstrained markets and only by those parent companies which own no more than 10,000 MW of unforced capacity in PJM.

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

12 Some resources had multiple associated offers.

514 units were zero and the offers for 26 units were set to zero because no data were submitted.[13] The transition adder was part of the offers on 206 units, of which offers on 12 units included only the transition adder. The transition adder had no impact on the clearing prices.

Of the 1,093 generating units which submitted offers, 130 (11.9 percent) included an Avoidable Project Investment Recovery Rate (APIR) component. As shown in Table 3, the APIR component added $83.25 per MW-day on average to the UCAP ACR value of these units. On a UCAP weighted average basis the APIR component added $195.85 per MW-day to the ACR value of these units. The default ACR values include an average APIR of $0.91 per MW-day. The maximum effect ($383.79 per MW-day) is the maximum amount by which an offer cap was increased by APIR. This value is less than the maximum APIR ($808.36 per MW-day) due to the net revenue offset to ACR plus APIR.

Table 2 ACR statistics: 2009-2010 RPM auction

Calculation Type	Number of Units	Percent of Generating Units Offered
Default ACR Selected	377	34.5%
ACR Data Input	151	13.8%
Opportunity Cost Input	10	0.9%
Transition Adder Only	12	1.1%
Offer Caps Calculated	550	50.3%
Uncapped New Units	3	0.3%
Generator Price Takers	540	49.4%
Generating Units Offered	1,093	100.0%
Demand Resources Offered	38	
Total Capacity Resources Offered	1,131	

13 Planned units are subject to mitigation only under specific conditions defined in the tariff. The seven other 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.

Table 3 APIR statistics: 2009-2010 RPM auction

	$ per MW-day UCAP
Average APIR	$83.25
UCAP Weighted Average APIR	$195.85
Maximum APIR	$808.36
Maximum APIR Effect	$383.79
Offers Caps with APIR	130

RPM Auction Results

MMU Methodology

The MMU reviewed the following inputs to and results of the 2009-2010 RPM auction: [14]

- **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 2001 through 2006;

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

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

- **Maximum EFORd –** Verified that the maximum equivalent demand forced outage rate (EFORd) used in base offer segments was the one-year EFORd ending September 30, 2006 or September 30, 2007;[15]

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14 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 2009-2010 RPM auction.

15 The tariff states that the EFORd that can be used in an auction can be no greater than the EFORd for the 12 months ending on the September 30 that last precedes the auction. Since

- **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.

Market Structure Tests

As shown in Table 4, all participants in the total PJM market as well as both LDA RPM markets failed the TPS test. The result was that offer caps were applied to all sell offers. Only those participants that fail the market power test are subject to offer capping. The RTO market includes all supply which cleared at or below the unconstrained clearing price. The LDA markets include the incremental supply inside the LDAs which was required to meet the demand for capacity in each LDA and which cleared at a price higher than the unconstrained price.

Table 4 presents the results of the TPS test using the Residual Supplier Index (RSI_x) as the metric.[16] A generation owner or owners are pivotal if the capacity of the owners' generation facilities is needed to meet the demand for capacity. 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

the 2009-2010 auction began on October1, 2007, generators could use the EFORd for the 12 months ending September 30, 2007 if the value was available for all of their units; otherwise, the EFORd for the 12 months ending September 30, 2006 was used.

16 See *2006 State of the Market Report* (March 8, 2007), Appendix J, "Three Pivotal Supplier Test" for additional discussion on the TPS test.

owners have a reduced ability to unilaterally influence market price. For example, seventy-four percent of participants in the RTO market failed the one pivotal supplier test using a market definition that includes all offers with costs less than or equal to 1.05 times the clearing price. [17]

Table 4 RSI results: 2009-2010 RPM auction[18]

	$RSI_{1\ 1.05}$	RSI_2	RSI_3
RTO	0.82	0.69	0.60
MAAC+APS	0.83	0.51	0.37
SWMAAC	0.57	0.01	0.00

RTO

Table 5 shows total RTO offer data for the 2009-2010 RPM auction, which includes the MAAC+APS and SWMAAC LDAs. Total internal RTO unforced capacity increased 350.2 MW from 156,968.0 MW in the 2008-2009 RPM auction to 157.318.2 MW due to new generation (437.5 MW), capacity upgrades to existing generation and increases in demand resources net of derations to existing generation and demand capacity resources. The 350.2 MW net increase consists of an increase of 733.9 MW, offset by a reduction (-383.7 MW) resulting from higher sell offer EFORds in the 2009-2010 auction.[19] As shown in Table 6, of the 733.9 MW, 513.3 MW (70.0 percent) were generation capmods and 220.6 MW (30.0 percent) were demand resources (DR) capmods. This value includes all generating units and DR that qualified as a PJM

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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 *2006 State of the Market Report* (March 8, 2007), Appendix J, "Three Pivotal Supplier Test" for additional discussion.

18 The RTO includes MAAC+APS, EMAAC and SWMAAC. MAAC+APS includes EMAAC and SWMAAC. In the 2009-2010 auction EMAAC was not constrained, so results for EMAAC are not shown. The reported RSI_x results are the lowest calculated for each market and test.

19 The net reduction of -383.7 MW due to the EFORd effect was the sum of -802.0 MW resulting from higher sell offer EFORds and 418.3 MW due to lower sell offer EFORds.

capacity resource for the 2009-2010 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.[20] The installed capacity (ICAP) of a unit may only be reduced through a capacity modification (capmod) 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.[21] 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 601.8 MW of ICAP and 733.9 MW of UCAP (Table 6). Capmod increases and decreases were the result of owner reevaluation of the capabilities of their generation and demand resources, at least partially in response to the incentives and penalties contained in RPM. After accounting for fixed resource requirement (FRR) committed resources and for imports, RPM capacity was 136,300.4 MW as compared to 136,237.3 MW in the 2008-2009 RPM auction.[22] FRR volumes increased by 332.2 MW and imports increased by 45.1 MW. RPM capacity was reduced by exports of 2,194.9 MW[23] and 104.3 MW which were excused from the RPM must-offer requirement as a result of non-utility generator (NUG) ownership questions (57.2 MW), planned reductions due to environmental regulations (33.5 MW), planned capacity withdrawals (5.5 MW), generation moving behind the meter (4.0 MW) and other factors (4.1 MW). Exports

[20] 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).

[21] See "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," Revision 04 (August 15, 2005), p. 8 <http://www.pjm.com/ contributions/pjm-manuals/pdf/m21.pdf> (228 KB). The manual states "the end of the next planning period."

[22] 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.

[23] If all of the exports had been offered into the auction at $0.00 per MW-day, the clearing price would have been approximately $82.00 per MW-day.

decreased 1,643.2 MW and excused volumes decreased 84.2 MW from the 2008-2009 RPM auction. Subtracting 450.2 MW of FRR optional volumes not offered, an increase of 120.1 MW in FRR MW not offered from the 2008-2009 RPM auction, resulted in 133,551.0 MW that were available to be offered into the auction, an increase of 1,670.4 MW.[24] After accounting for the above, all capacity resources were offered into the RPM auction. Total offers included 1,151.3 MW of EFORd offer segments as compared to 1,711.1 MW of EFORd offer segments in the 2008-2009 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 132,231.8 MW of cleared resources for the entire RTO, which represented a reserve margin of 17.8 percent, resulted in net excess of 1,784.0 MW greater than the reliability requirement of 130,447.8 MW (IRM of 15.0 percent).[25] [26] [27] Net excess increased 381.0 MW from the net excess of 1,403.0 MW in the 2008–2009 RPM auction. This increase in net excess was due to the increase in supply, mainly from decreased exports, exceeding the demand growth as reflected in the increase in the reliability requirement. The ILR forecast less FRR demand response decreased 1.9 MW from 1,663.6 MW in the 2008-2009 auction to 1,661.7 MW. As shown in Figure 1, the downward sloping demand curve resulted in a price of $102.04 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 $52.86 per MW-day.

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24 FRR entities are allowed to offer into the RPM auction excess volumes above their FRR quantities, subject to a sales cap amount. The 450.2 MW are excess volumes included in the sales cap amount which were not offered into the auction.

25 The reserve margin of 17.8 percent was calculated by subtracting DR and ILR from the peak load. If DR and ILR were counted as resources in the calculation, then the reserve margin would be 17.6 percent. Both calculations include FRR resources and FRR load and are on an ICAP basis.

26 The RTO reliability requirement, which is after FRR adjustments, is plotted on the VRR curve as the reliability requirement less the ILR forecast obligation plus any FRR DR.

27 Net excess is defined as the cleared volumes less the reliability requirement.

As shown in Figure 3, the RTO clearing price decreased from $111.92 per MW-day in the 2008–2009 auction to $102.04 per MW-day in the 2009–2010 auction. While offered volumes (supply) increased by 1,670.4 MW from 131,880.6 MW to 133,551.0 MW, the overall RTO reliability requirement, from which the demand curve is developed, increased by 2,253.2 MW from 128,194.6 MW to 130,447.8 MW.[28] The increase in the reliability requirement, due to an increase in the preliminary forecast peak load, would shift the RTO market demand curve to the right if everything else were constant. However, as a result of changes in the constrained LDA markets the 2009-2010 RTO market demand curve shifted to the left of the 2008-2009 demand curve (Figure 3). More MW cleared in the constrained LDAs (5,314.7 MW) in 2009-2010 than the 2,253.2 increase in demand, shifting the RTO market demand curve to the left since the RTO market demand curve excludes incremental demand which cleared in MAAC+APS and SWMAAC. More volumes cleared in the LDAs due to increased CETL values.[29] Though offered volumes increased, higher CETL values allowed more lower priced generation from the RTO to clear in the LDAs, thereby preventing the RTO price from decreasing even further.[30]

Table 7 shows the composition of the offers on the steeply sloped portion of the RTO supply curve (Figure 1) from $12.00 per MW-day up to and including the highest offer

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28 The demand curve UCAP quantities are based on three points, which are ratios of the installed reserve margin (IRM =15.0%) 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 UCAP prices are based on factors multiplied by net CONE divided by 1 minus the pool wide EFORd. Net CONE is defined as the cost of new entry (CONE) minus the energy and ancillary services revenue offset (E&AS). For the three points, the factors are 1.5, 1.0 and 0.2. For 2009-2010, CONE was $197.83 per MW-day and E&AS was $36.12 MW-day.

29 See "Planning Period Parameters" (October 29, 2007) <http://www.pjm.com/markets/rpm/downloads/planning-period-parameters.xls> (36.5 KB).

30 An analysis of the contributions of changes in CETL and the VRR curve to changes in the RTO clearing price, as provided for the 2008-2009 auction, is not possible as there is no 2008-2009 base line data for MAAC+APS which is a newly defined LDA for 2009-2010.

of $339.00 per MW-day. Combustion turbines, coal and oil/gas steam units made up 80.1 percent of the offers on this section of the supply curve, most with APIR. The last offer to clear was for a combustion turbine in EMAAC.

As shown in Table 5, the preliminary net load price that LSEs will pay is $102.04 per MW-day in the RTO area not included in the constrained LDAs. 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 interruptible load for reliability (ILR) for the delivery year and the forecasted RTO ILR obligation.

Figure 4 shows that the RTO would have cleared at approximately $165.00 per MW-day compared to $125.00 per MW-day in the 2008-2009 auction if there had been no constraints and the RTO had cleared as a single market with the downward sloping demand curve. In both cases, these prices are greater than the clearing prices for the unconstrained part of the RTO (the RTO market), but less than the clearing prices for the constrained LDAs.

Table 5 RTO offer statistics: 2009-2010 RPM auction[31]

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Total Internal RTO Capacity (Gen and DR)	166,639.7	157,318.2		
FRR	(25,316.2)	(23,523.2)		
Imports	2,652.5	2,505.4		
RPM Capacity	143,976.0	136,300.4		
Exports	(2,376.2)	(2,194.9)		
FRR Optional	(552.5)	(450.2)		
Excused	(136.8)	(104.3)		
Available	140,910.5	133,551.0	100.0%	100.0%
Generation Offered	140,003.6	132,614.2	99.4%	99.3%
DR Offered	906.9	936.8	0.6%	0.7%
Total Offered	140,910.5	133,551.0	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO	133,859.0	126,917.1	95.0%	95.0%
Cleared in LDAs	5,594.4	5,314.7	4.0%	4.0%
Total Cleared	139,453.4	132,231.8	99.0%	99.0%
Uncleared in RTO	895.5	869.0	0.6%	0.7%
Uncleared in LDAs	561.6	450.2	0.4%	0.3%
Total Uncleared	1,457.1	1,319.2	1.0%	1.0%
Reliability Requirement		130,447.8		
Total Cleared		132,231.8		
Net Excess/(Deficit)		1,784.0		
ILR Forecast - FRR DR		1,661.7		
Resource Clearing Price ($ per MW-day)		$102.04	A	
Preliminary Zonal Capacity Price ($ per MW-day)		$102.04	B	
Final Zonal CTR Credit Rate ($ per MW-day)		$0.00	C	
Final Zonal ILR Price ($ per MW-day)		$102.04	A-C	
Preliminary Net Load Price ($ per MW-day)		$102.04	B-C	

31 Prices are only for those generating units outside of MAAC+APS and SWMAAC.

Table 6 Capacity modifications: 2009-2010 RPM auction[32], [33]

	ICAP (MW)			UCAP (MW)		
	RTO	MAAC+APS	SWMAAC	RTO	MAAC+APS	SWMAAC
Generation Increases	1,239.2	404.8	33.0	1,213.0	393.5	31.7
Generation Decreases	(852.4)	(598.1)	(494.4)	(699.7)	(433.3)	(329.9)
Generation Net Increase/(Decrease)	386.8	(193.3)	(461.4)	513.3	(39.8)	(298.2)
DR Increases	565.5	509.5	108.9	584.0	526.1	112.5
DR Decreases	(350.5)	(350.5)	(67.5)	(363.4)	(362.9)	(70.2)
Net DR Increase/(Decrease)	215.0	159.0	41.4	220.6	163.2	42.3
Net Capacity Resource Increase/(Decrease)	601.8	(34.3)	(420.0)	733.9	123.4	(255.9)

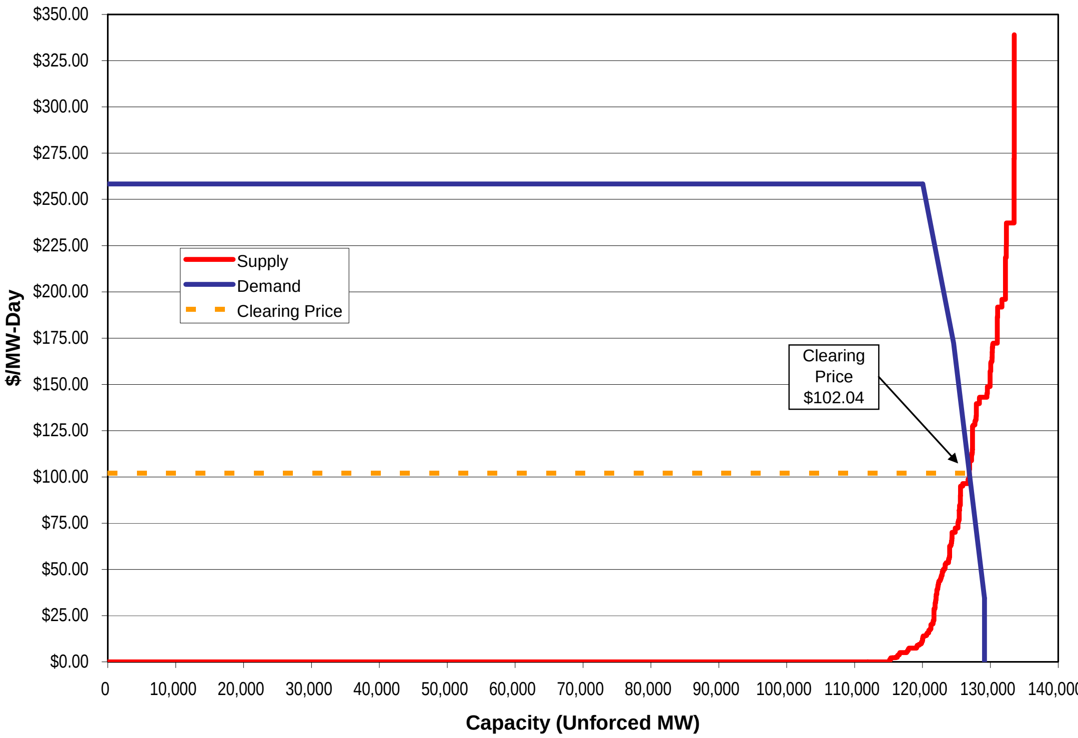
Table 7 Offers between $12.00 and $150.00 on RTO supply curve: 2009-2010 RPM auction

Offer/Technology Type	UCAP (MW)	Percent of Vertical Offers
DR	481.4	3.6%
EFORd Offer Segment	1,149.8	8.5%
Combustion Turbine	3,286.0	24.4%
Subcritical Coal	2,613.4	19.3%
Supercritical Coal	2,483.7	18.3%
Oil/Gas Steam	2,459.3	18.1%
Combined Cycle	624.7	4.6%
Pumped Storage	422.4	3.1%
Diesel	19.8	0.1%
Total	13,540.5	100.0%

32 Only capmods that had a start date after June 1, 2008 and on or before June 1, 2009 are included.

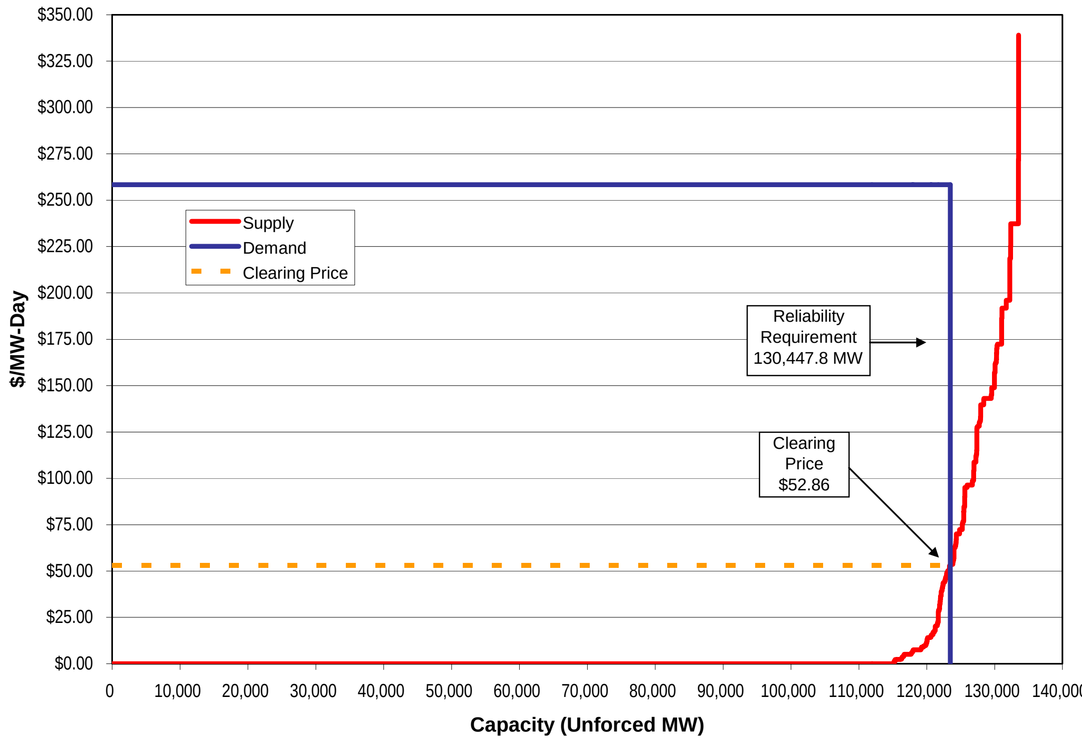
33 The RTO includes MAAC+APS, EMAAC and SWMAAC. MAAC+APS includes EMAAC and SWMAAC. In the 2009-2010 auction EMAAC was not constrained, so results for EMAAC are not shown.

Figure 1 PJM RTO market supply/demand curves: 2009-2010 RPM auction[34]



[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+APS and SWMAAC.

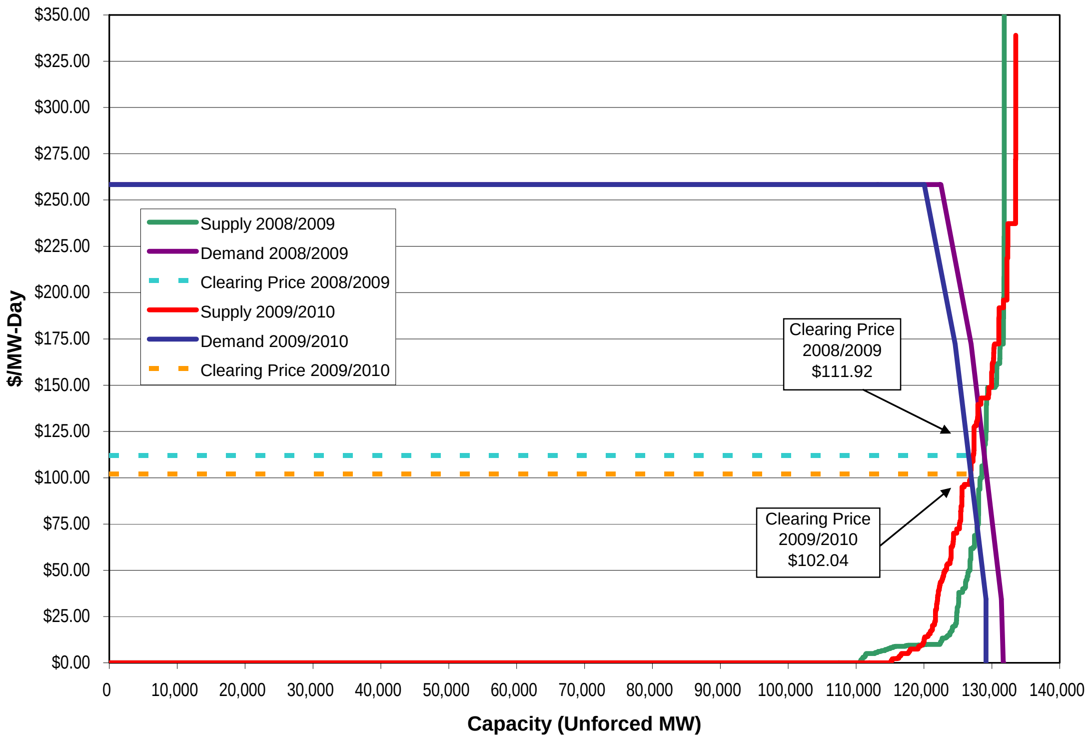
Figure 2 PJM RTO supply/demand curves at reliability requirement: 2009-2010 RPM auction[35, 36]



35 The supply curve includes all supply offers at the lower of offer price or offer cap. The demand curve includes all demand in the entire RTO, including MAAC+APS and SWMAAC.

36 The reliability requirement is plotted on the VRR curve as the reliability requirement less the ILR forecast obligation plus any FRR DR.

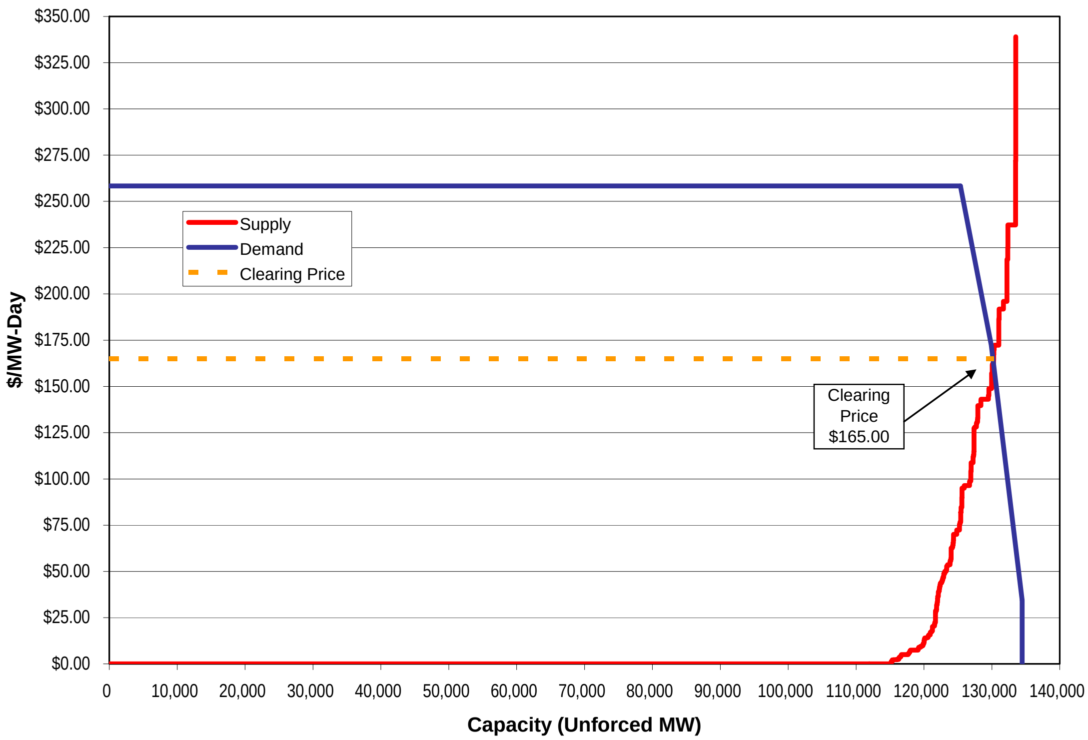
Figure 3 PJM RTO market supply/demand curves: 2008-2009 and 2009-2010 RPM auctions[37, 38]



37 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+APS and SWMAAC.

38 For ease of viewing, the graph was truncated at $350.00 per MW-day and does not show an uncleared offer of approximately $800.00 per MW-day.

Figure 4 PJM RTO supply/demand curves: 2009-2010 RPM auction[39]



MAAC+APS[40]

Table 8 shows total MAAC+APS offer data for the 2009-2010 RPM auction. Total internal MAAC+APS unforced capacity of 73,012.9 MW includes all generating units and demand resources that qualified as a PJM capacity resource, excluding external units, and also includes owners' modifications to ICAP ratings (Table 6). Multiple owners submitted both positive and negative capacity modifications, which resulted in a net decrease of 34.3 MW of ICAP and a net increase of 123.4 MW of UCAP. Including imports of 89.3 MW into MAAC+APS, RPM capacity was 73,102.2 MW. This amount was reduced by 104.3 MW which were excused from the RPM must-offer requirement as

39 The supply curve includes all supply offers at the lower of offer price or offer cap. The demand curve includes all demand in the entire RTO, including MAAC+APS and SWMAAC.

40 A comparison to the 2008-2009 auction for MAAC+ APS is not possible due to a lack of 2008-2009 data for MAAC+APS since it is a newly defined LDA for 2009-2010.

a result of non-utility generator (NUG) ownership questions (57.2 MW), planned reductions due to environmental regulations (33.5 MW), planned capacity withdrawals (5.5 MW), generation moving behind the meter (4.0 MW) and other factors (4.1 MW), resulting in 72,997.9 MW that were available to be offered into the auction. After accounting for the above exception, all capacity resources were offered into the RPM auction.

Of the 72,547.7 MW cleared in MAAC+APS, 67,233.0 MW were cleared in the RTO before MAAC+APS became constrained. Once the constraint was binding, based on the 4,941.0 MW capacity emergency transfer limit (CETL) value, only the incremental supply located in MAAC+APS was available to meet the incremental demand in the LDA. Of the 5,764.9 MW of incremental supply, 5,314.7 MW cleared, which resulted in a resource clearing price of $191.32 per MW-day, as shown in Figure 5. The price was determined by the intersection of the incremental supply and demand curves. The last offer to clear was a DR offer. The 450.2 MW of uncleared volumes were the result of offer prices which exceeded the clearing price. Except for 6.7 MW of DR and 17.0 MW of base offer segments without APIR, all of the uncleared volumes were base offer segments with APIR.

As shown in Table 8, total resources available to MAAC+APS were 77,488.7 MW, which was 414.2 MW (0.5 percent) less than the reliability requirement of 77,902.9 MW. The ILR forecast was 1,055.7 MW. If the demand curve had been vertical at the incremental reliability requirement with the same maximum price as for the downward sloping demand curve in Figure 5, the clearing price would have been $196.00 per MW-day, as shown in Figure 6.

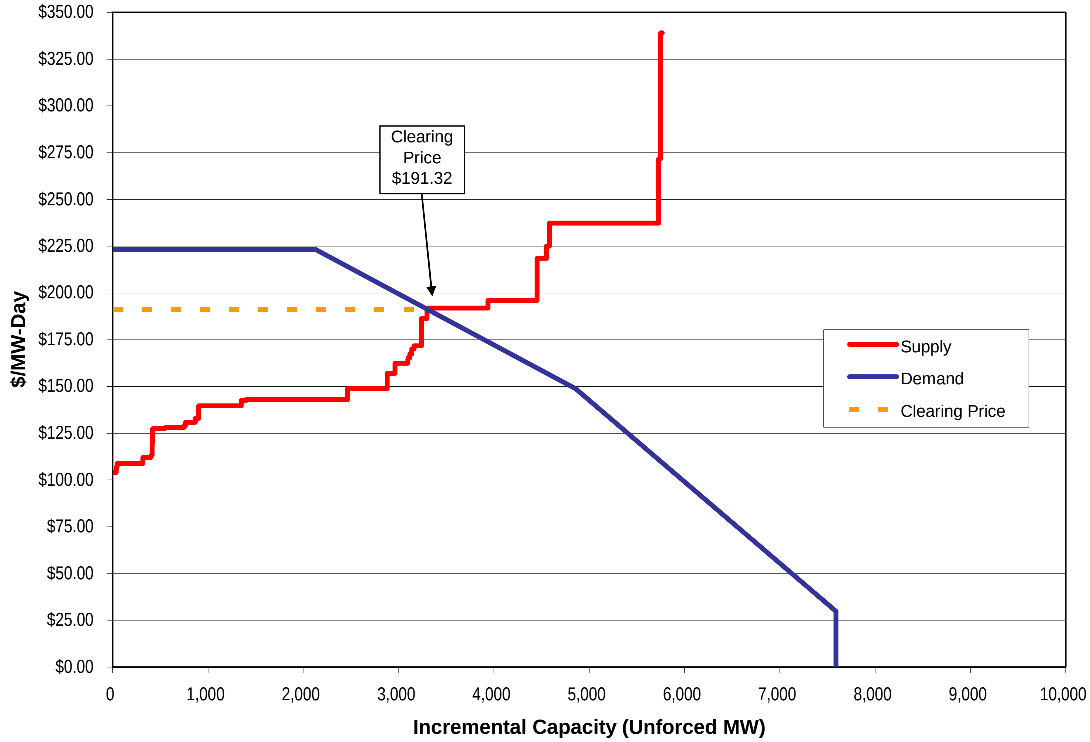
The preliminary net load price that LSEs will pay is $188.55 per MW-day (Table 8). This value is the preliminary zonal capacity price ($191.32 per MW-day) less the final capacity transfer right (CTR) credit rate ($2.77 per MW-day). The final zonal capacity price will be calculated three months before the delivery year when the resource clearing price is adjusted for differences between the certified interruptible load for reliability (ILR) for the delivery year and the forecasted RTO ILR obligation. The CTR MW value allocated to load in an LDA is the LDA UCAP obligation less the cleared generation internal to the LDA less the ILR forecast for the LDA. This MW value is multiplied by the locational price adder for the LDA to arrive at the economic value of the CTRs allocated to the load in the LDA. This value is then divided by the LDA UCAP obligation to arrive at the final CTR credit rate for the LDA. The final CTR credit rate is an allocation of the economic value of transmission import capability that exists in constrained LDAs and serves to offset a portion of the locational price adder charged to load in constrained LDAs. The CTR credit is not based on the total CETL, the total MW of capacity from outside the LDA that helps meet the LDA obligation, because the load in the LDA must pay for the capacity obligation at the clearing price and not for the capacity deliverable to the LDA.

Table 8 MAAC+APS offer statistics: 2009-2010 RPM auction[41]

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Total Internal MAAC+APS Capacity (Gen and DR)	77,870.6	73,012.9		
Imports	89.3	89.3		
RPM Capacity	77,959.9	73,102.2		
Exports	0.0	0.0		
Excused	(136.8)	(104.3)		
Available	77,823.1	72,997.9	100.0%	100.0%
Generation Offered	77,028.6	72,177.3	99.0%	98.9%
DR Offered	794.5	820.6	1.0%	1.1%
Total Offered	77,823.1	72,997.9	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO	71,667.1	67,233.0	92.1%	92.1%
Cleared in LDAs	5,594.4	5,314.7	7.2%	7.3%
Total Cleared	77,261.5	72,547.7	99.3%	99.4%
Uncleared	561.6	450.2	0.7%	0.6%
Reliability Requirement		77,902.9		
Total Cleared		72,547.7		
CETL		4,941.0		
Total Resources		77,488.7		
Net Excess/(Deficit)		(414.2)		
ILR Forecast		1,055.7		
Resource Clearing Price ($ per MW-day)		$191.32	A	
Preliminary Zonal Capacity Price ($ per MW-day)		$191.32	B	
Final Zonal CTR Credit Rate ($ per MW-day)		$2.77	C	
Final Zonal ILR Price ($ per MW-day)		$188.55	A-C	
Preliminary Net Load Price ($ per MW-day)		$188.55	B-C	

41 Prices are only for those generating units inside of MAAC+APS, excluding SWMAAC.

Figure 5 MAAC+APS incremental supply/demand curves: 2009-2010 RPM auction[42]



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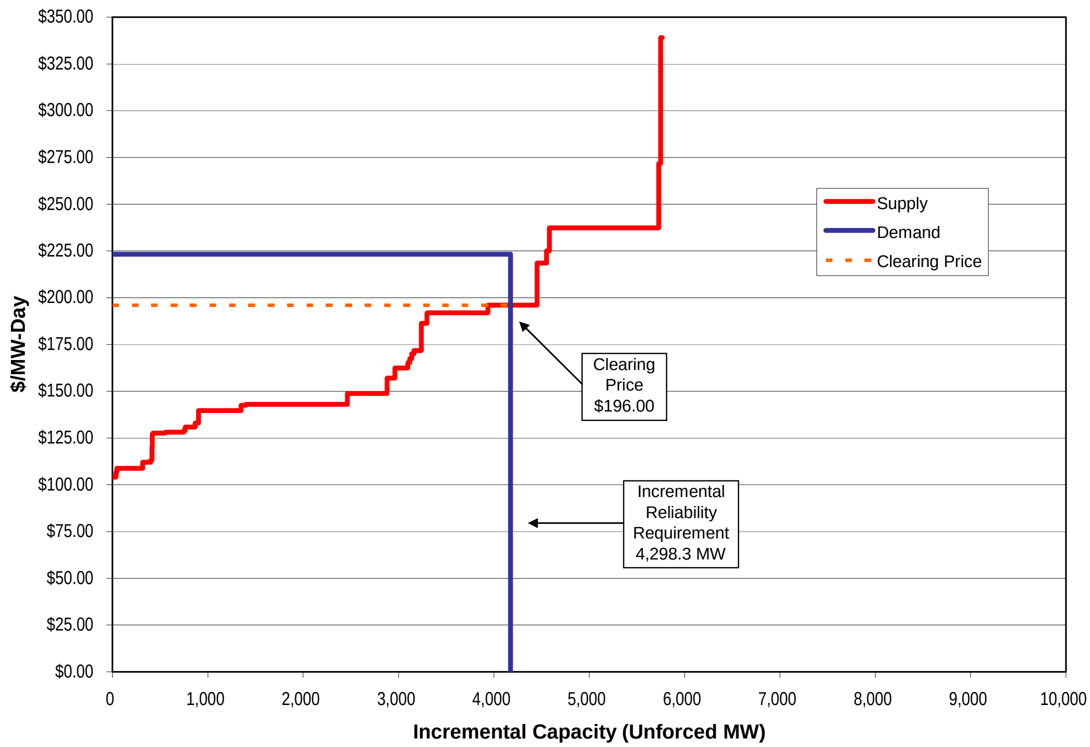
42 The supply curve includes all supply offers at the lower of offer price or offer cap. The demand curve excludes incremental demand which cleared in SWMAAC.

Figure 6 MAAC+APS incremental supply/demand curves at reliability requirement: 2009-2010 RPM auction[43, 44]



Southwestern MAAC (SWMAAC)

Table 9 shows total SWMAAC offer data for the 2009-2010 RPM auction. Total internal SWMAAC unforced capacity, which includes all generating units and demand resources that qualified as a PJM capacity resource, excluding external units, and also includes owners' modifications to ICAP ratings (Table 6), decreased 431.9 MW from 10,777.1 MW in the 2008-2009 auction to 10,345.2 MW. This decrease was due to upgrades to existing generation and increases in demand resources, net of derations to existing generation and demand capacity resources. Multiple owners submitted both positive and negative

43 The supply curve includes all supply offers at the lower of offer price or offer cap. The demand curve includes all demand in MAAC+APS, including SWMAAC.

44 The reliability requirement is plotted on the VRR curve as the reliability requirement less the ILR forecast obligation.

capacity modifications, which resulted in a net decrease of 420.0 MW of ICAP and 255.9 MW of UCAP in SWMAAC. Of the 431.9 MW decrease in total internal SWMAAC unforced capacity, 176.0 MW were due to higher sell offer EFORds in the 2009-2010 auction resulting from updated EFORds.[45] Of the remaining 255.9 MW decrease in unforced capacity, 298.2 MW (116.5 percent) were generation capmods and -42.3 MW (-16.5 percent) were DR capmods. Since there were no imports from outside PJM into SWMAAC, RPM capacity was 10,345.2 MW. This amount was reduced by 33.5 MW which were excused from the RPM must-offer requirement as a result of planned reductions due to environmental regulations, resulting in 10,311.7 MW that were available to be offered into the auction, a decrease of 314.4 MW. After accounting for the above exception, all capacity resources were offered into the RPM auction, with offered volumes decreasing by 314.4 MW from 10,626.1 MW to 10,311.7 MW.

Of the 9,914.6 MW cleared in SWMAAC, which was a decrease of 706.6 MW from the 2008-2009 auction, 6,202.3 MW were cleared in the RTO before MAAC+APS became constrained and 1,695.7 MW were cleared in MAAC+APS before SWMAAC became constrained. Once the constraint was binding, based on the 6,391.0 CETL value, only the incremental supply in SWMAAC was available to meet the incremental demand in the LDA. Of the 2,413.7 MW of incremental supply, 2,016.6 MW cleared, which resulted in a resource clearing price of $237.33 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 a base offer segment.

The 397.1 MW of uncleared volumes, which increased 392.2 MW from 4.9 MW, were the result of offer prices which exceeded the clearing price, all of which were base offer segments. As shown in Figure 9, the 2009-2010 clearing price increased $27.22 per MW-day from $210.11 per MW-day in the 2007–2008 auction. A combination of factors led to the increase in the clearing price. A 781.0 MW increase in CETL from 5,610.0 MW to 6,391.0 MW, which would normally lower LDA prices due to the import of more lower priced generation, was partially offset by a corresponding 220.0 MW increase in CETO from 5,940.0 MW to 6,160.0 MW. Unit derations, 144.3 MW of which were for

[45] The net increase of 176.0 MW due to the EFORd effect was the sum of -187.4 MW resulting from higher sell offer EFORds and 11.4 MW due to lower sell offer EFORds.

environmental regulations, resulted in less available capacity, which when combined with increased offer prices due to higher APIR to meet environmental regulations and the higher CETO resulted in the higher clearing price.[46]

As shown Table 9, total resources available to SWMAAC were 16,305.6 MW, which was 13.2 MW (0.1 percent) less than the reliability requirement of 16,318.8 MW. The ILR forecast decreased 0.5 MW from 346.2 MW in the 2008-2009 auction to 345.7 MW. If the demand curve had been vertical at the incremental reliability requirement with the same maximum price as for the downward sloping demand curve in Figure 7, the clearing price would have been $238.56 per MW-day, as shown in Figure 8.

As shown in Table 9, the preliminary net load price that LSEs will pay is $218.12 per MW-day. This value is the preliminary zonal capacity price ($237.33 per MW-day) less the final CTR credit rate ($19.21 per MW-day). 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 interruptible load for reliability (ILR) for the delivery year and the forecasted RTO ILR obligation.

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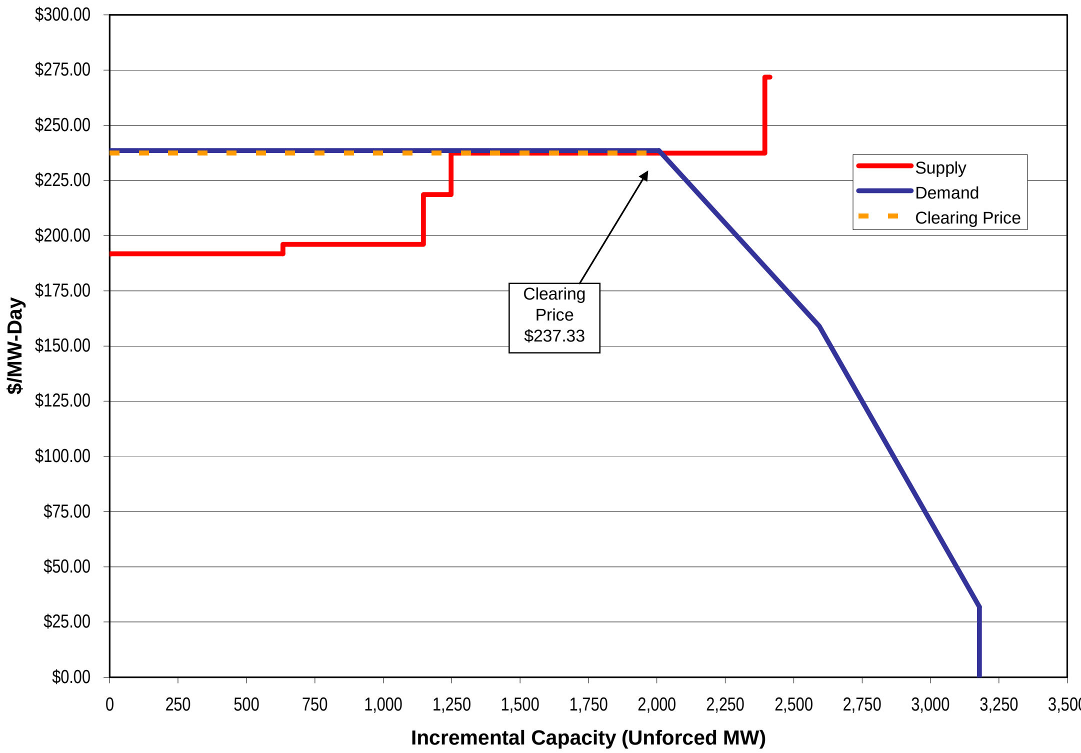
46 See "Planning Period Parameters" (October 29, 2007) <http://www.pjm.com/markets/rpm/downloads/planning-period-parameters.xls> (36.5 KB).

Table 9 SWMAAC offer statistics: 2009-2010 RPM auction

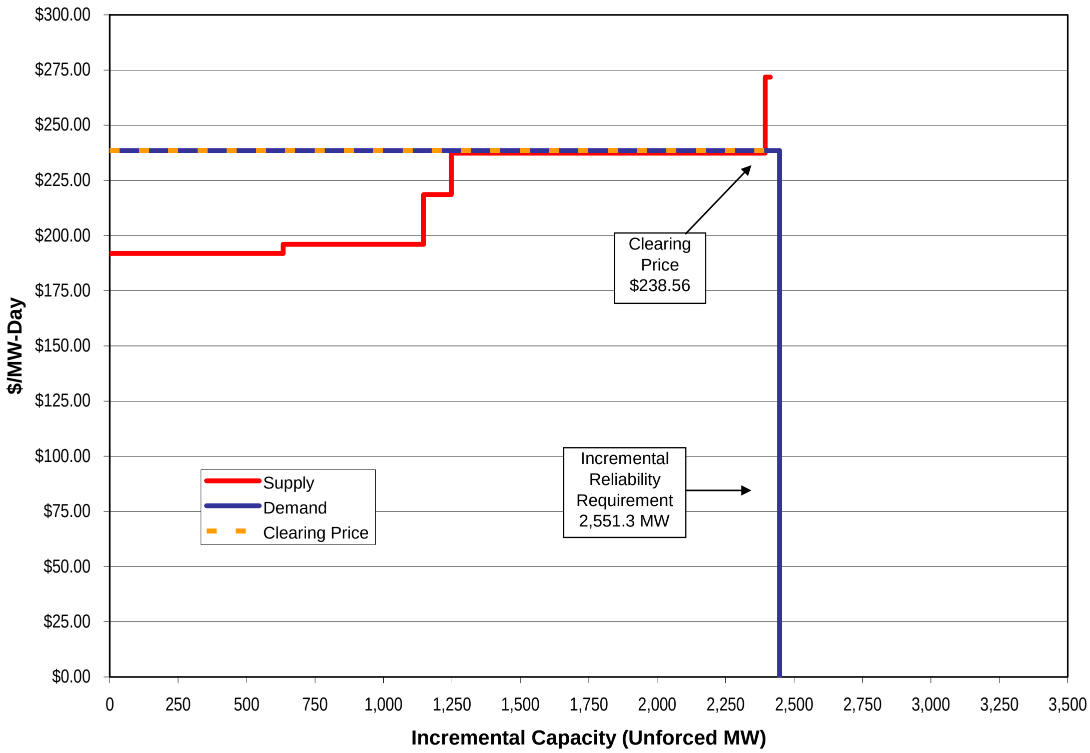
	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Total Internal SWMAAC Capacity (Gen and DR)	11,448.6	10,345.2		
Imports	0.0	0.0		
RPM Capacity	11,448.6	10,345.2		
Exports	0.0	0.0		
Excused	(37.0)	(33.5)		
Available	11,411.6	10,311.7	100.0%	100.0%
Generation Offered	11,066.7	9,955.4	97.0%	96.5%
DR Offered	344.9	356.3	3.0%	3.5%
Total Offered	11,411.6	10,311.7	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO	7,001.2	6,202.3	61.4%	60.1%
Cleared in MAAC+APS	1,784.3	1,695.7	15.6%	16.4%
Cleared in LDA	2,146.2	2,016.6	18.8%	19.6%
Total Cleared	10,931.7	9,914.6	95.8%	96.1%
Uncleared	479.9	397.1	4.2%	3.9%
Reliability Requirement		16,318.8		
Total Cleared		9,914.6		
CETL		6,391.0		
Total Resources		16,305.6		
Net Excess/(Deficit)		(13.2)		
ILR Forecast		345.7		
Resource Clearing Price ($ per MW-day)		$237.33	A	
Preliminary Zonal Capacity Price ($ per MW-day)		$237.33	B	
Final Zonal CTR Credit Rate ($ per MW-day)		$19.21	C	
Final Zonal ILR Price ($ per MW-day)		$218.12	A-C	
Preliminary Net Load Price ($ per MW-day)		$218.12	B-C	

Figure 7 SWMAAC incremental supply/demand curves: 2009-2010 RPM auction[47]



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

Figure 8 SWMAAC incremental supply/demand curves at reliability requirement: 2009-2010 RPM auction[48, 49]



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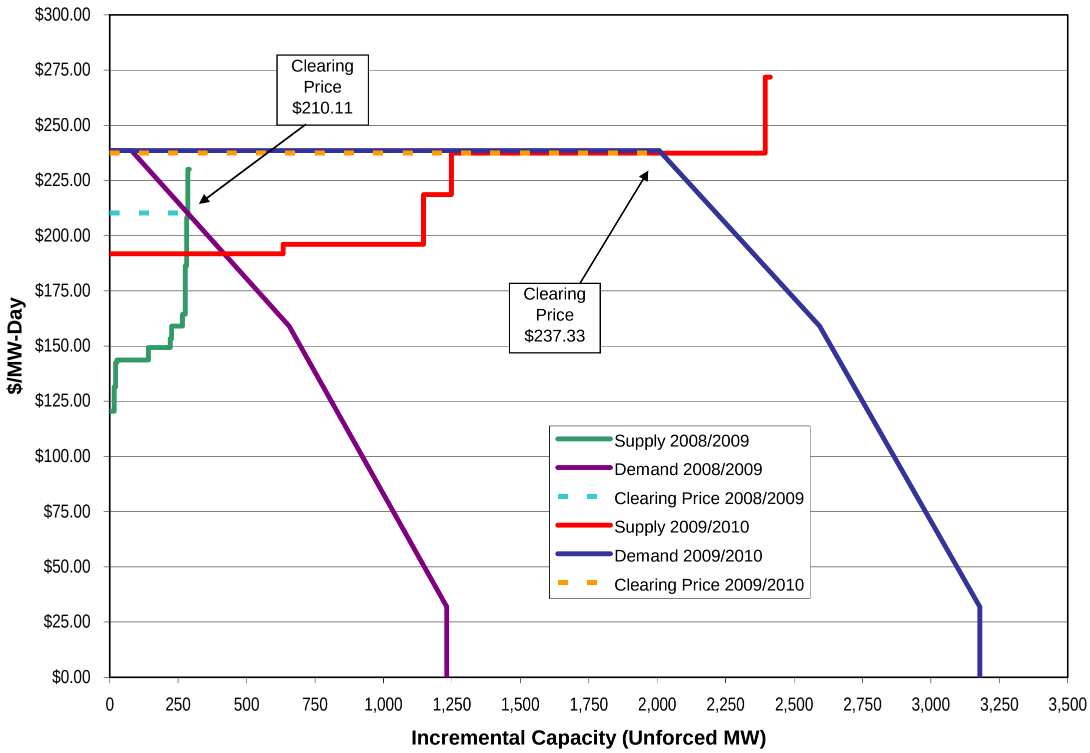
48 The supply curve includes all supply offers at the lower of offer price or offer cap.

49 The reliability requirement is plotted on the VRR curve as the reliability requirement less the ILR forecast obligation.

Figure 9 SWMMAC incremental supply/demand curves: 2008-2009 and 2009-2010 RPM auctions[50]



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.

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

The LM program introduced two RPM-related products:

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

- **Interruptible Load for Reliability (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 10, the LM program provided 3,044.3 MW, which is a combination of DR offered into the RPM auction and forecast ILR for the 2009–2010 delivery year. DR offers increased 221.0 MW from 715.8 MW in the 2008-2009 auction. Total LM volumes increased 1,367.6 MW over the final ALM MW provided before the implementation of RPM. ILR will be certified three months before the delivery year.

Table 10 Load management statistics: 2009-2010 RPM auction[51]

	UCAP (MW)		
	RTO	MAAC+APS	SWMAAC
DR Offered	936.8	820.6	356.3
ILR Forecast	2,107.5	1,055.7	345.7
Total Load Management	3,044.3	1,876.3	702.0
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 resources 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

51 The RTO includes MAAC+APS, EMAAC and SWMAAC. MAAC+APS includes EMAAC and SWMAAC. In the 2009-2010 auction EMAAC was not constrained, so results for it are not shown .

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 resources offer into an RPM base residual auction and receive the auction clearing price while ILR will be certified and receive the final zonal ILR price (see Table 9 for example).

CETO/CETL[52]

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.[53] 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 Process (RTEPP). However, if transmission upgrades

52 See "PJM Manual 14B: Generation and Transmission Interconnection Planning, Attachment E: PJM Deliverability Methods," Revision 10 (March 1, 2007), <http://www.pjm.com/contributions/pjm-manuals/pdf/m14b-redline.pdf >.

53 Manual 14B indicates that all "electrically cohesive load areas" are tested.

cannot be built prior to a delivery year to increase the CETL value, locational constraints could result under RPM, causing locational price differences.[54]

An LDA with CETL less than 1.05 times CETO is modeled as a constrained LDA in RPM. An LDA may also be modeled as a constrained LDA even if CETL is more than 1.05 times CETO if there are other reliability concerns. A reliability requirement and a variable resource requirement curve will be established for each constrained LDA.

54 See "PJM Manual 18: PJM Capacity Market," Revision 0 (Effective June 1, 2007), p. 12, <http://www.pjm.com/contributions/pjm-manuals/pdf/m18.pdf> (604 KB).

Attachment A

Preliminary Market Structure Screen

As stated in section 6.3 (a)(i) of Attachment DD of the PJM Tariff, "the Market Monitoring Unit shall apply the Preliminary Market Structure Screen (PMSS) to identify the LDAs in which Capacity Market Sellers must provide the data specified in section 6.7(b) for any auction conducted with respect to such Delivery Year and whether Capacity Market Sellers must provide this data for the entire PJM Region. For each LDA and for the PJM Region, the PMSS will be based on: (1) the Unforced Capacity available for such Delivery Year from Generation Capacity Resources located in such area; and (2) the Locational Deliverability Area Reliability Requirement and the PJM Reliability Requirement."

As stated in section 6.3 (a)(ii)Section of Attachment DD of the PJM Tariff, "An LDA, Unconstrained LDA Group,[1] or the entire PJM Region shall fail the Preliminary Market Structure Screen, and Capacity Market Sellers owning or controlling any Generation Capacity Resource located in such LDA, Unconstrained LDA Group, or region shall be required to provide the information specified in section 6.7(b), if any one of the following three conditions is met: (1) the market share of any Capacity Market Seller exceeds twenty percent; (2) the HHI for all such sellers is 1800 or higher; or (3) there are not more than three jointly pivotal suppliers."

Results

The Market Monitoring Unit applied the PMSS for the 2009-2010 Auction using Unforced Capacity from eRPM effective as of June 1, 2009 and the LDA and PJM Reliability Requirements for 2009-2010. As shown in the table below, all LDAs and the entire PJM Region failed the PMSS. As a result, except for the provisional exceptions listed, all Capacity Market Sellers owning or controlling any Generation Capacity Resource located in such LDA or the entire PJM Region shall be required to provide the information specified in section 6.7(b).

[1] PJM did not define an Unconstrained LDA Group for this Auction.

RPM Preliminary Market Structure Screen Results: 2009-2010

	Highest Market Share	HHI	Pivotal Suppliers	Pass/Fail
RTO	18.4%	853	1	Fail
EMAAC	31.3%	2053	1	Fail
SWMAAC	51.1%	4229	1	Fail
MAAC+APS	26.9%	1627	1	Fail

Data Requirements

As stated in section 6.7(b) of Attachment DD of the PJM Tariff, "Except as provided in subsection (c) below, potential participants in any PJM Reliability Pricing Model Auction in any LDA or unconstrained LDA Group that fails the Preliminary Market Structure Screen (or, if such region fails the screen, potential auction participants in the entire PJM Region) shall, in addition, submit the following data, (all submitted data is subject to verification by the MMU) together with supporting documentation for each item, to the Market Monitoring Unit no later than two months prior to the conduct of such auction:"

Provisional Exceptions

As stated in section 6.7(c) of Attachment DD of the PJM Tariff, "Potential auction participants identified in subsection (b) above need not submit the data specified in that subsection for any Generation Capacity Resource: (i) that is in an Unconstrained LDA Group or, if this is the relevant market, the entire PJM Region, and is in a resource class determined by the Market Monitoring Unit as not likely to include the marginal price-setting resources in such auction; or (ii) for which the potential participant commits that any Sell Offer it submits as to such resource shall not include any price above the level identified for the relevant resource class by the Market Monitoring Unit."

The Market Monitoring Unit has identified the following resource classes as not likely to include the marginal price-setting resources in such auction. The following resource classes in the zones outside of the EMAAC and SWMAAC LDAs are provisionally excepted for the following unit types:[2]

- Nuclear units
- Coal units
- Combustion Turbines less than 10 years of age

In addition, combined cycle units in zones outside of EMAAC and SWMAAC, if an owner has more than one combined cycle unit and that owner provides data on one combined cycle unit, are provisionally excepted from the requirement to provide data in 6.7 (b).

[2] Provisionally excepted means that it is excepted unless the Market Monitoring Unit requires the data, per section 6.7(c).