Market Monitoring Unit

Analysis of the 2010/2011 RPM Auction Revised

PJM Market Monitoring Unit

July 3, 2008

Introduction

This report, prepared by the PJM Market Monitoring Unit (MMU), reviews the functioning of the fourth Reliability Pricing Model (RPM) auction (for the 2010/2011 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 2010-2011 RPM auction were competitive.

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.[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

1 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).

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 2010-2011 RPM auction. As shown in Table 1, all four 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. Each of the four areas also failed 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.[5] 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.[6]

---

3 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).

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 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).

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

Table 1 Preliminary Market Structure Screen results: 2010-2011[7, 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 2010/2011 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

7 As of October 1, 2007, when PMSS results were posted, PJM had not updated the planning parameters for the 2010-2011 RPM delivery year, so data as of June 1, 2009 had to be used.

8 The RTO includes MAAC+APS, EMAAC, SWMAAC and DPL-South. MAAC+APS includes but is not limited to the EMAAC, SWMAAC and DPL-South LDAs.

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.

As shown in Table 2, 1,104 generating units submitted offers compared to 1,093 generating units offered in the 2009/2010 RPM auction. The net increase of 11 units consisted of 15 new units, four reactivated units and three units from the FRR participant, offset by three retired units, four deactivated units, three units exported from PJM and one unit excused from offering. There were seven new CT units (270.5 MW), three new diesel units (16.4 MW), five new wind units (120.0 MW) and four reactivated units (165.0 MW) for a total of 19 units. There were three units that retired (358.3 MW), four units that were deactivated (52.9 MW) and an additional three units exported out of PJM (521.5 MW) for a total of 10 units.[10] There were 23 demand resources (DR) offered compared to 38 DR resources offered in the 2009/2010 RPM auction.[11]

Unit-specific offer caps were calculated for 154 units (13.9 percent) including 134 units (12.1 percent) with an Avoidable Project Investment Recovery Rate (APIR) component and 20 units (1.8 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 532 units (48.1 percent), of which 370 (33.5 percent) were the default ("proxy") offer caps calculated and posted by the MMU. Of the 1,104 generating units, 15 new units had uncapped offers

---

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

11 Some resources had multiple associated offers.

while the remaining 557 units were price takers, of which the offers for 546 units were zero and the offers for 11 units were set to zero because no data were submitted.[12]

As shown in Table 3, the weighted-averages for units with APIR for ACR ($360.27 per MW-day) and offer caps ($110.25 per MW-day) were higher than the ACR ($84.04 per MW-day) and offer caps ($20.33 per MW-day) for units without an APIR component, including units for which the default value was selected. The APIR component added $272.18 per MW-day to the ACR value of the APIR units.[13,14] The default ACR values include an average APIR of $0.91 per MW-day. The highest APIR for a technology ($494.87 per MW-day) was for subcritical/supercritical coal units. The maximum APIR effect ($577.03 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

---

12 Planned units are subject to mitigation only under specific conditions defined in the tariff. Some of the 15 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.

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

14 The 134 units which had an APIR component submitted $1.5 billion for capital projects associated with 13,111.0 MW of UCAP.

Table 2 ACR statistics: 2010/2011 RPM auction

Calculation Type	Number of Units	Percent of Generating Units Offered
Default ACR selected	370	33.5%
ACR data input (APIR)	134	12.1%
ACR data input (non-APIR)	20	1.8%
Opportunity cost input	8	0.7%
Offer caps calculated	532	48.1%
Uncapped new units	15	1.4%
Generator price takers	557	50.5%
Generating units offered	1,104	100.0%
Demand resources offered	23	
Total capacity resources offered	1,127	

Table 3 APIR statistics: 2010/2011 RPM auction[15]

	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	$34.62	$26.66	$67.57	$166.13	$82.55		$84.04
Net revenues	$98.19	$17.97	$15.19	$299.64	$391.00		$157.33
Offer caps	$10.55	$14.30	$52.38	$7.12	$4.53	$124.60	$20.33
APIR units							
ACR	$61.61	$49.26	$290.64	$630.85	$34.62		$360.27
Net revenues	$26.84	$10.32	$83.61	$535.68	$2.07		$263.27
Offer caps	$37.30	$39.41	$207.04	$123.85	$32.55		$110.25
APIR	$9.87	$30.93	$198.78	$494.87	$22.42		$272.18
Maximum APIR effect							$577.03

15 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 2010/2011 RPM auction: [16]

- **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;
- **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.

---

16 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 2010/2011 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 as well as both LDA RPM markets failed the TPS test. [17] The result was that offer caps were applied to all sell offers except sell offers for new units. The RTO market includes all supply. The constrained LDA markets include the incremental supply inside the constrained LDAs which was offered at a price higher than the unconstrained clearing price for the 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. [18]

Table 4 RSI results: 2010/2011 RPM auction

	$RSI_{1\ 1.05}$	RSI_3
RTO	0.60	0.60
DPL-South	0.00	0.00

17 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

18 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 2010/2011 RPM auction, including the DPL-South LDA. Total internal RTO unforced capacity increased 1,712.7 MW (1.1 percent) from 157,318.2 MW in the 2009-2010 RPM auction to 159,030.9 MW as a result of new generation (406.9 MW), reactivated units (165.0), 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 1,712.7 MW increase, 1,657.7 MW (96.8 percent) were net generation capacity modifications (cap mods) and 43.7 MW (2.6 percent) were net DR modifications (DR mods).[19] The remaining increase of 11.3 MW (0.6 percent) was due to net lower sell offer EFORds and a higher forecast pool requirement (FPR) which is used in the calculation of the UCAP value of DR.[20] Total internal RTO unforced capacity includes all generating units and DR that qualified as PJM capacity resources for the 2010/2011 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.[21] 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.[22] Otherwise the owner must take an outage, as appropriate, if the owner cannot provide energy consistent with the ICAP of the unit.

---

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

20 DR (UCAP) = DR nominated value (ICAP) * DR factor * FPR. The DR factor (0.955) is used to determine the reliability benefit of load management. The FPR (1.0833) increased due to an increase in both the installed reserve margin (IRM) from 15.0 percent to 15.5 percent and an increase in the pool-wide average EFORd from 6.13 percent to 6.21 percent.

21 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).

22 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."

Multiple owners submitted both positive and negative capacity modifications, with a net RTO increase of 1,817.6 MW of ICAP and 1,712.7 MW of UCAP (Table 6). 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. After accounting for fixed resource requirement (FRR) committed resources and for imports, RPM capacity was 137,360.7 MW compared to 136,300.4 MW in the 2009/2010 RPM auction.[23] FRR volumes increased by 897.7 MW and imports increased by 245.3 MW. RPM capacity was reduced by exports of 3,147.4 MW and 490.1 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 (166.2 MW), planned reductions due to environmental regulations (33.0 MW), and other factors (15.0 MW).[24] Exports increased 952.5 MW and excused volumes increased 385.8 MW from the 2009/2010 RPM auction. Subtracting 630.5 MW of FRR optional volumes not offered, an increase of 180.3 MW in FRR MW not offered from the 2009/2010 RPM auction, resulted in 133,092.7 MW that were available to be offered into the auction, a decrease of 458.3 MW.[25] After accounting for the above, all capacity resources were offered into the RPM auction. Total offers included 1,034.9 MW of EFORd offer segments compared to 1,151.3 MW of EFORd offer segments in the 2009/2010 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 132,190.4 MW of cleared resources for the entire RTO, which represented a reserve margin of 16.5 percent, resulted in net excess of 1,149.2 MW over the reliability requirement of 132,698.8 MW

[23] 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.

[24] If all of the exports had been offered into the auction at $0.00 per MW-day, the clearing price would have been approximately $132.00 per MW-day.

[25] FRR entities are allowed to offer into the RPM auction excess volumes above their FRR quantities, subject to a sales cap amount. The 630.5 MW are a combination of excess volumes included in the sales cap amount which were not offered into the auction and volumes above the sales cap amount which were precluded from being offered into the auction.

(IRM of 15.5 percent).[26, 27] Net excess decreased 2,296.2 MW from the net excess of 3,445.7 MW in the 2009/2010 RPM auction. This decrease in net excess was due to the decrease in supply, mainly due to increased FRR volumes and increased exports, and an increase in demand as reflected in the increase in the reliability requirement. The interruptible load for reliability (ILR) forecast less FRR demand response decreased 4.1 MW from 1,661.7 MW in the 2009/2010 auction to 1,657.6 MW. As shown in Figure 1, the downward sloping demand curve resulted in a price of $174.29 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 $131.87 per MW-day.

As shown in Figure 3, the RTO clearing price increased from $102.04 per MW-day in the 2009/2010 auction to $174.29 per MW-day in the 2010/2011 auction. Offered volumes decreased 458.3 MW from 133,551.0 MW to 133,092.7 MW while the overall RTO reliability requirement, from which the demand curve is developed, increased 2,251.0 MW from 130,447.8 MW to 132,698.8 MW.[28] The increase in the reliability requirement, due to an increase in the preliminary forecast peak load, shifted the RTO market demand curve to the right. The RTO market demand curve was not affected by the

---

26 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. Net excess calculations for auctions prior to 2010/2011 were originally calculated as cleared capacity less the reliability requirement. For comparison purposes the 2009/2010 net excess has been recalculated.

27 The IRM increased from 15.0 percent to 15.5 percent for the 2010/2011 delivery year. The supply curve crossed the VRR (demand) curve at Point B, which is IRM plus one percent.

28 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 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 $34.37 MW-day.

market dynamics in the LDAs as no incremental demand cleared in the LDAs. [29] (See Figure 3.) MAAC and SWMAAC import constraints were not binding. DPL-South import constraints were binding, but no volumes cleared in DPL-South.[30]

Table 7 shows the composition of the offers on the steeply sloped portion of the RTO supply curve (Figure 1) from $25.00 per MW-day up to and including the highest offer of $400.00 per MW-day. Oil/gas steam, combustion turbines and coal units made up 82.3 percent of the offers on this section of the supply curve, most with APIR. The last offer to clear was for an EFORd offer segment in the RTO.

As shown in Table 5, the preliminary net load price that LSEs will pay is $174.29 per MW-day in the RTO area not included in DPL[31]. 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.

Figure 4 shows that the RTO would have cleared at $174.29 per MW-day if there had been no constraints and the RTO had cleared as a single market with the downward sloping demand curve. In 2010/2011, this price was the same as the constrained price as no volumes cleared in the LDAs.

---

29 See "Planning Period Parameters" (January 11, 2008) <http://www.pjm.com/markets/rpm/downloads/20071026-2010-2011-planning-period-parameters.xls> (29.0 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 2009/2010 base line data for DPL-South which is a newly constrained LDA for 2010/2011.

31 Load in DPL will pay a DPL zone weighted average price based on DPL-South and non-DPL-South prices.

Table 5 RTO offer statistics: 2010/2011 RPM auction[32]

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Total internal RTO capacity (gen and DR)	168,457.3	159,030.9		
FRR	(26,305.7)	(24,420.9)		
Imports	2,982.4	2,750.7		
RPM capacity	145,134.0	137,360.7		
Exports	(3,378.2)	(3,147.4)		
FRR optional	(744.5)	(630.5)		
Excused	(546.2)	(490.1)		
Available	140,465.1	133,092.7	100.0%	100.0%
Generation offered	139,529.5	132,124.8	99.3%	99.3%
DR offered	935.6	967.9	0.7%	0.7%
Total offered	140,465.1	133,092.7	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO	139,253.9	132,190.4	99.1%	99.3%
Cleared in LDAs	0.0	0.0	0.0%	0.0%
Total cleared	139,253.9	132,190.4	99.1%	99.3%
Uncleared in RTO	1,184.5	875.9	0.9%	0.7%
Uncleared in LDAs	26.7	26.4	0.0%	0.0%
Total uncleared	1,211.2	902.3	0.9%	0.7%
Reliability requirement		132,698.8		
Total cleared		132,190.4		
ILR forecast		2,110.5		
FRR DR		(452.9)		
Net excess/(deficit)		1,149.2		
Resource clearing price ($ per MW-day)		$174.29	A	
Preliminary zonal capacity price ($ per MW-day)		$174.29	B	
Base zonal CTR credit rate ($ per MW-day)		$0.00	C	
Preliminary zonal ILR price ($ per MW-day)		$174.29	B-C	
Preliminary net load price ($ per MW-day)		$174.29	B-C	

32 Prices are only for those generating units outside of DPL-South.

Table 6 Capacity modifications: 2010/2011 RPM auction[33]

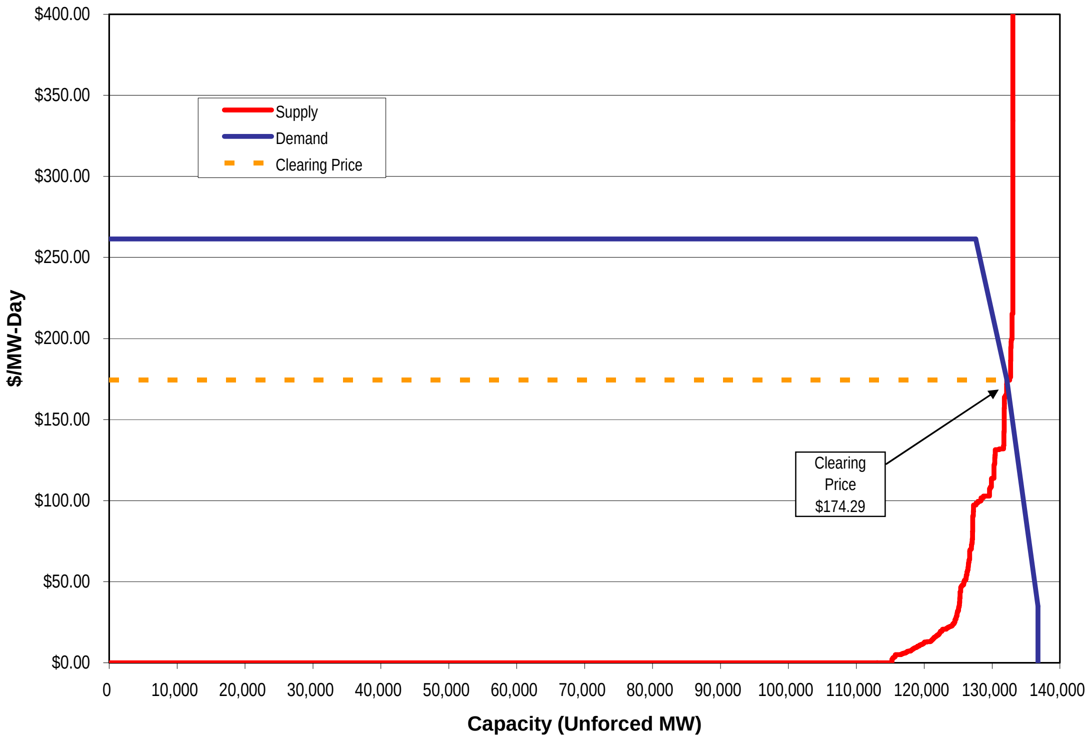
	ICAP (MW)		UCAP (MW)	
	RTO	DPL - South	RTO	DPL - South
Generation increases	2,071.5	0.0	1,903.1	0.0
Generation decreases	(294.8)	(92.0)	(245.4)	(85.5)
Capacity modifications net increase/(decrease)	1,776.7	(92.0)	1,657.7	(85.5)
DR increases	597.3	15.2	618.5	15.7
DR decreases	(556.4)	0.0	(574.8)	0.0
DR modifications increase/(decrease)	40.9	15.2	43.7	15.7
Net capacity/DR modifications increase/(decrease)	1,817.6	(76.8)	1,701.4	(69.8)
EFORd effect			10.4	28.9
DR effect			0.9	0.0
Net Internal Capacity Increase/(Decrease)	1,817.6	(76.8)	1,712.7	(40.9)

Table 7 Offers greater than $25.00 on RTO supply curve: 2010/2011 RPM auction

Offer/Technology Type	UCAP (MW)	Percent of Vertical Offers
DR	407.1	4.7%
EFORd offer segment	1,034.9	12.0%
Oil/gas steam	2,836.6	32.9%
Combustion turbine (CT)	2,393.3	27.9%
Supercritical coal	1,121.4	13.0%
Subcritical coal	731.5	8.5%
Combined cycle	77.6	0.9%
Diesel	5.4	0.1%
Total	8,607.8	100.0%

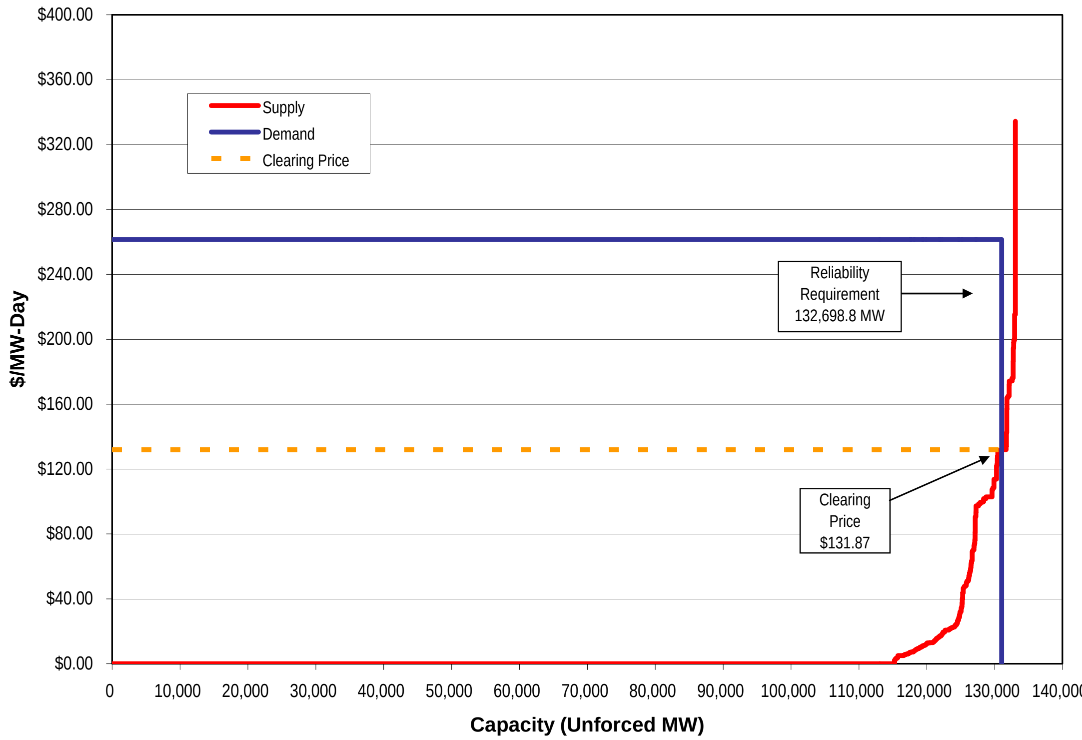
33 Only cap mods and DR mods that had a start date after June 1, 2009 and on or before June 1, 2010 are included.

Figure 1 PJM RTO market supply/demand curves: 2010/2011 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 DPL-South.

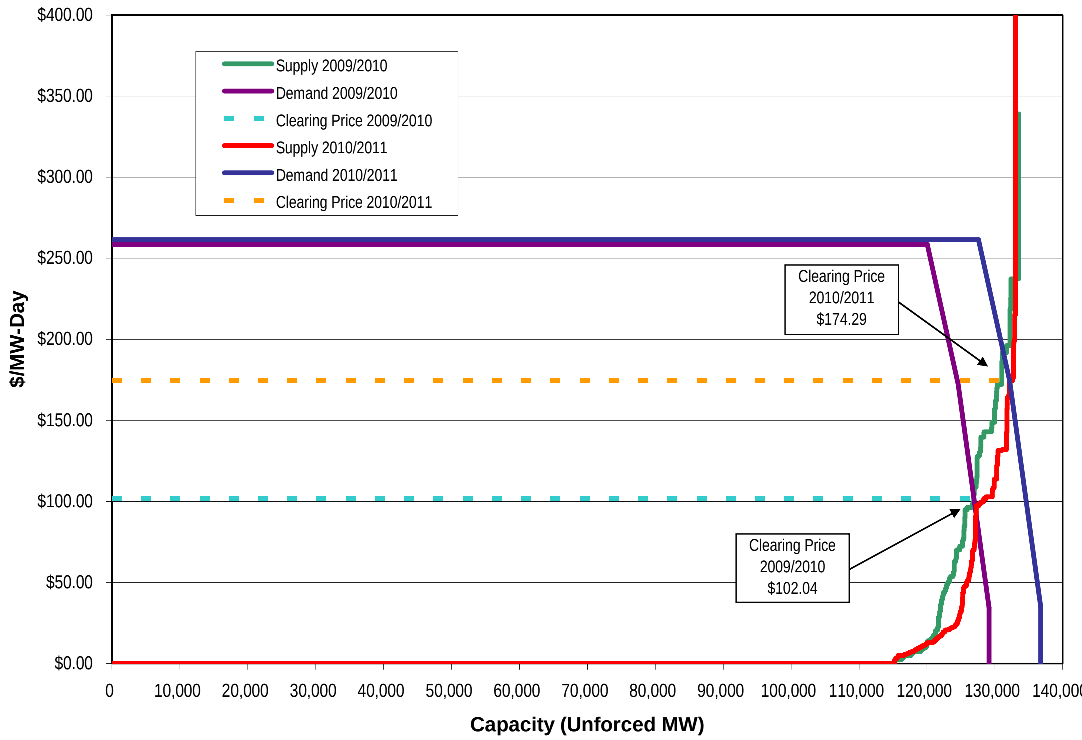
Figure 2 PJM RTO supply/demand curves at reliability requirement: 2010/2011 RPM auction[35, 36]



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 DPL-South.

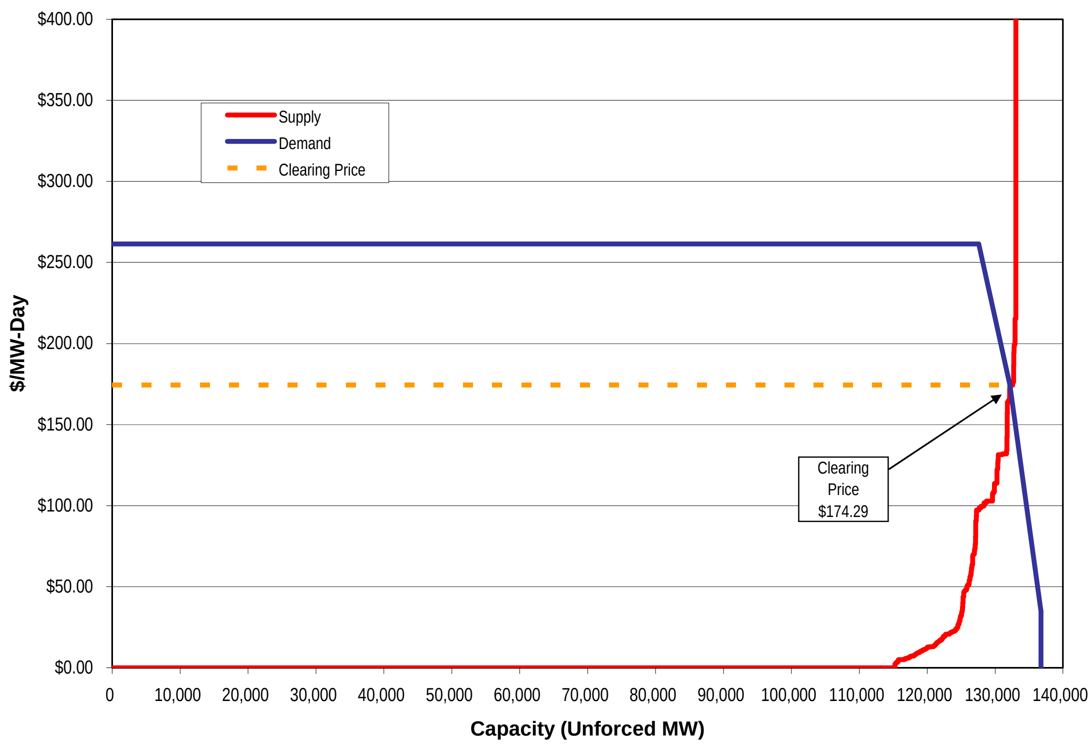
36 The demand curve is the RTO reliability requirement less demand which cleared in DPL-South less the RTO ILR forecast obligation plus any FRR DR.

Figure 3 PJM RTO market supply/demand curves: 2009/2010 and 2010/2011 RPM auctions[37]



[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 DPL-South.

Figure 4 PJM RTO supply/demand curves: 2010/2011 RPM auction[38]



DPL-South[39]

Table 8 shows total DPL-South offer data for the 2010/2011 RPM auction. Total internal DPL-South unforced capacity of 1,546.1 MW includes all generating units and DR that qualified as PJM capacity resources, 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 76.8 MW of ICAP and a net decrease of 40.9 MW of UCAP. RPM capacity was 1,546.1 MW, all of which was offered into the auction.

---

38 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 DPL-South.

39 A comparison to the 2009/2010 auction for DPL-South is not possible due to a lack of 2009/2010 data DPL-South since it is a newly constrained LDA for 2010/2011.

All of the 1,519.7 MW cleared in DPL-South were cleared in the RTO before DPL-South became constrained. Once the constraint was binding, only the incremental supply located in DPL-South was available to meet the incremental demand in the LDA. None of the 26.4 MW of remaining DPS-South supply cleared because all 26.4 MW were priced above the demand curve.

The price paid in DPL-South is a scarcity price which resulted from the fact that there was demand in DPL-South that could not be met by supply priced below the demand curve. Imports were not available due to the binding constraint and all of the remaining supply in DPL-South was priced above the demand curve. Although no MW actually cleared in DPL-South after the constraint became binding, there was a separate, constrained DPL-South price. The final DPL-South price of $186.12 per MW-day was determined by the intersection of the incremental demand curve and a vertical section of the incremental supply curve (Figure 5). The vertical section of the incremental supply curve connected the last cleared DPL-South offer of $171.69 per MW-day (this offer cleared in the RTO) and the next highest supply offer in DPL-South of $186.30 per MW-day. The last cleared DPL-South offer was a DR offer. All of the uncleared volumes were base offer segments based on opportunity costs except for 0.8 MW of DR.

As shown in Table 8, total resources in DPL-South were 2,966.7 MW, which when combined with the ILR forecast of 22.2 MW resulted in a net excess of -60.5 MW (2.0 percent) less than the reliability requirement of 3,049.4 MW. If the demand curve had been vertical at the incremental reliability requirement with the same maximum price as the downward sloping demand curve in Figure 5, the clearing price would have been $197.80 per MW-day, as shown in Figure 6.

The preliminary net load price that LSEs will pay is $178.27 per MW-day (Table 8). The DPL zonal price is the weighted average of the price paid in DPL-South and the price paid in the balance of the zone (the RTO clearing price). This value is the preliminary zonal capacity price ($178.57 per MW-day) less the base zonal capacity transfer right (CTR) credit rate ($0.30 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 ILR for the delivery year and the forecasted RTO ILR obligation.

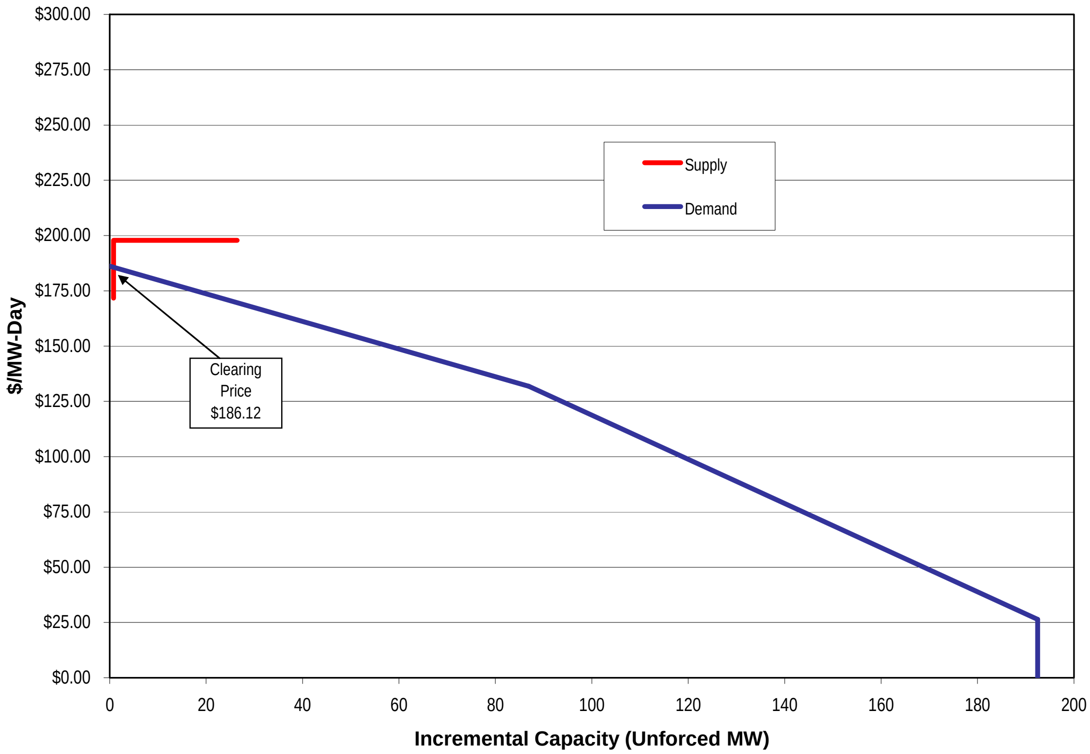
CTRs are assigned to load in a constrained LDA or zone because all load in an LDA pays the higher constrained LDA clearing price while only the capacity located in the LDA receives the clearing price. The capacity which is imported into the LDA receives the lower clearing price where it is located. The difference in value for the imported MW is credited to load in the LDA as CTRs. The CTR MW value allocated to load in an LDA is the LDA UCAP obligation (less the ILR forecast for the LDA) less the cleared generation internal to 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.

Table 8 DPL-South offer statistics: 2010/2011 RPM auction[40]

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Total internal DPL-South capacity (gen and DR)	1,652.3	1,546.1		
Imports	0.0	0.0		
RPM capacity	1,652.3	1,546.1		
Exports	0.0	0.0		
Excused	0.0	0.0		
Available	1,652.3	1,546.1	100.0%	100.0%
Generation offered	1,637.1	1,530.4	99.1%	99.0%
DR offered	15.2	15.7	0.9%	1.0%
Total offered	1,652.3	1,546.1	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO	1,625.6	1,519.7	98.4%	98.3%
Cleared in LDA	0.0	0.0	0.0%	0.0%
Total cleared	1,625.6	1,519.7	98.4%	98.3%
Uncleared	26.7	26.4	1.6%	1.7%
Reliability requirement		3,049.4		
Total cleared		1,519.7		
CETL		1,447.0		
Total resources		2,966.7		
ILR forecast		22.2		
Net excess/(deficit)		(60.5)		
Resource clearing price ($ per MW-day)		$186.12	A	
Preliminary zonal capacity price ($ per MW-day)		$178.57	B	
Base zonal CTR credit rate ($ per MW-day)		$0.30	C	
Preliminary zonal ILR price ($ per MW-day)		$178.27	B-C	
Preliminary net load price ($ per MW-day)		$178.27	B-C	

40 The resource clearing price is only for those generating units inside of DPL-South. The zonal capacity price, zonal CTR credit rate, zonal ILR price and zonal net load price are DPL zone weighted average prices based on prices for the constrained DPL-South and for the balance of DPL.

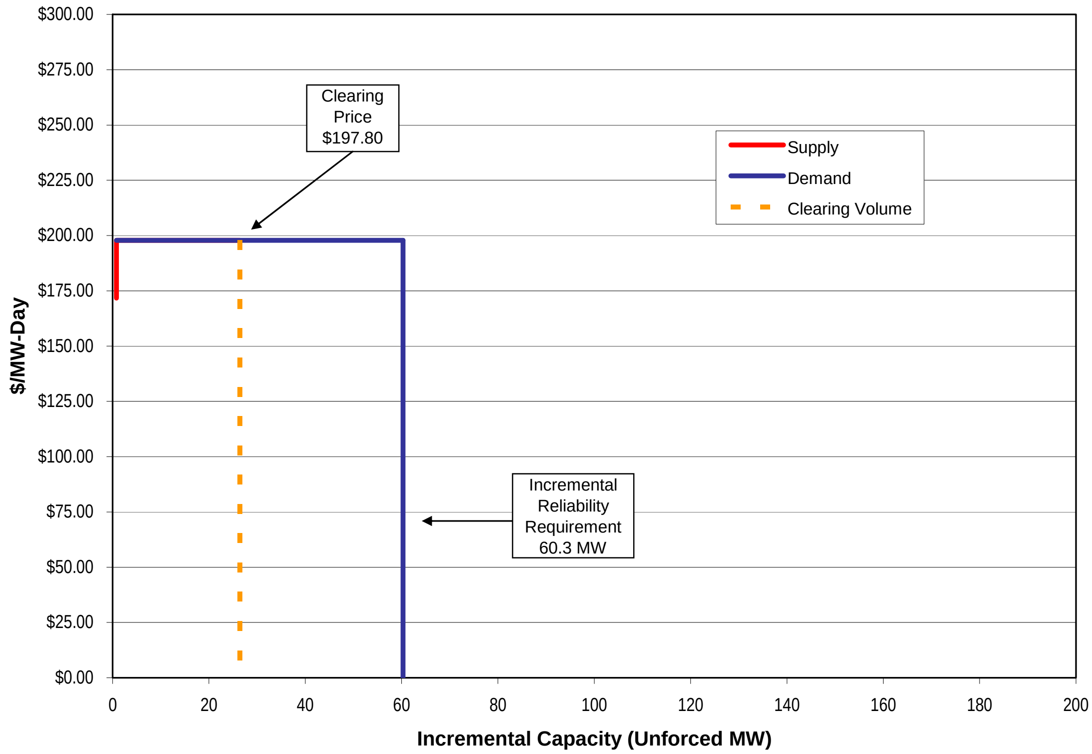
Figure 5 DPL-South incremental supply/demand curves: 2010/2011 RPM auction[41, 42]



[41] The supply curve includes incremental DPL-South supply offers at the lower of offer price or offer cap which did not clear in the RTO.

[42] The demand curve only includes incremental DPS-South demand which did not clear in the RTO.

Figure 6 DPL-South incremental supply/demand curves at reliability requirement: 2010/2011 RPM auction[43, 44]



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.

43 The supply curve includes incremental DPL-South supply offers at the lower of offer price or offer cap which did not clear in the RTO.

44 The demand curve is the DPL-South reliability requirement less DPL-South demand which cleared in the RTO less the DPL-South ILR forecast.

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 3,078.4 MW, which is a combination of DR offered into the RPM auction and forecast ILR for the 2010/2011 delivery year. DR offers increased 31.1 MW from 936.8 MW in the 2009-2010 auction. Total LM volumes increased 1,401.7 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: 2010/2011 RPM auction

	UCAP (MW)	
	RTO	DPL - South
DR offered	967.9	15.7
ILR forecast	2,110.5	22.2
Total load management	3,078.4	37.9
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).

CETO/CETL

Since the ability to import energy and capacity into LDAs may be limited by the existing transmission capability, a load deliverability analysis is conducted for each LDA. [45] 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 cannot be built prior to a delivery year to increase the CETL value, locational constraints could result under RPM, causing locational price differences.[46]

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 are established for each constrained LDA.

---

[45] 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.

[46] See PJM. "Manual 18: PJM Capacity Market," Revision 2 (Effective February 21, 2008), p. 18, <http://www.pjm.com/contributions/pjm-manuals/pdf/m18.pdf> (604 KB).