SECTION 5 – CAPACITY MARKET

Each organization serving PJM load must meet its capacity obligations by acquiring capacity resources through the PJM Capacity Market, where load serving entities (LSEs) must pay the locational capacity price for their zone. LSEs can affect the financial consequences of purchasing capacity in the capacity market by constructing generation and offering it into the capacity market, by entering into bilateral contracts, by developing demand-side resources and Energy Efficiency (EE) resources and offering them into the capacity market, or by constructing transmission upgrades and offering them into the capacity market.

Overview

The Market Monitoring Unit (MMU) analyzed market structure, participant conduct and market performance in the PJM Capacity Market for the first nine months of calendar year 2010, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.

RPM Capacity Market

Market Design

On June 1, 2007, the Reliability Pricing Model (RPM) Capacity Market design was implemented in the PJM region, replacing the Capacity Credit Market (CCM) design that had been in place since 1999.[1] The RPM design represents a significant change in the structure of the Capacity Market in PJM. The RPM is a forward-looking, annual, locational market, with a must offer requirement for capacity and mandatory participation by load, with performance incentives for generation, that includes clear, market power mitigation rules and that permits the direct participation of demand-side resources.

Under RPM, capacity obligations are annual. Base Residual Auctions (BRAs) are held for delivery years that are three years in the future. Effective with the 2012/2013 delivery year, First, Second and Third Incremental Auctions (IA) are held for each delivery year.[2] Prior to the 2012/2013 delivery year, the Second Incremental Auction is conducted if PJM determines than an unforced capacity resource shortage exceeds 100 MW of unforced capacity due to a load forecast increase. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[3] Previously, First, Second, and Third Incremental Auctions were conducted 23, 13, and four months, respectively, prior to the delivery year. Also effective for the 2012/2013 delivery year, a conditional incremental auction may be held if there is a need to procure additional capacity resulting from a delay in a planned large transmission upgrade that was modeled in the BRA for the relevant delivery year.[4]

RPM prices are locational and may vary depending on transmission constraints.[5] Existing generation capable of qualifying as a capacity resource must be offered into RPM Auctions, except for resources owned by entities that elect the Fixed Resource Requirement (FRR) option. Participation by LSEs is mandatory, except for those entities that elect the FRR option. There is an administratively determined demand curve that defines scarcity pricing levels and that, with the supply curve derived from capacity offers, determines market prices in each BRA. RPM rules provide performance incentives for generation, including the requirement to submit generator outage data and the linking of capacity payments to the level of unforced capacity. Under RPM there are explicit market power mitigation rules that define the must offer requirement, that define structural market power, that define offer caps based on the marginal cost of capacity and that have flexible criteria for competitive offers by new entrants or by entrants that have an incentive to exercise monopsony power. Demand-side resources and Energy Efficiency resources may be offered directly into RPM auctions and receive the clearing price without mitigation.

Market Structure

- **Supply.** Total internal capacity increased 1,712.7 MW from 157,318.2 MW on June 1, 2009, to 159,030.9 MW on June 1, 2010.[6] This increase was the result of 406.9 MW of new generation, 165.0 MW that came out of retirement, 1,085.8 MW of generation uprates, 43.7 MW of demand

1 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in the *2010 Quarterly State of the Market Report for PJM: January through September*, Section 5, "Capacity Market" and include all capacity within the PJM footprint.

2 126 FERC ¶ 61,275 (2009).

3 *PJM Interconnection, L.L.C.*, OATT Revisions, Docket No. ER10-366-000 (December 1, 2009).

4 See 126 FERC ¶ 61,275 (March 26, 2009), p. 34.

5 Transmission constraints are local capacity import capability limitations (low capacity emergency transfer limit (CETL) margin over capacity emergency transfer objective (CETO)) caused by transmission facility limitations, voltage limitations or stability limitations.

6 Unless otherwise specified, all volumes are in terms of unforced capacity (UCAP).

resource (DR) modifications (mods), and an increase of 11.3 MW due to lower Equivalent Demand Forced Outage Rates (EFORds).

In the 2011/2012, 2012/2013, and 2013/2014 auctions, new generation increased 3,969.4 MW; 486.9 MW came out of retirement and net generation deratings were 5,050.1 MW, for a total of -593.8 MW. DR and EE capacity modifications totaled 11,360.5 MW through June 1, 2013. A decrease of 1,481.8 MW was due to higher EFORds. The reclassification of the Duquesne resources as internal added 3,187.2 MW to total internal capacity, and the integration of the ATSI zone resources added 13,175.2 MW. The net effect from June 1, 2010, to June 1, 2013, was an increase in total internal capacity of 25,647.3 MW (16.1 percent) from 159,030.9 MW to 184,678.2 MW.

In the 2010/2011 auction, 11 more generating resources made offers than in the 2009/2010 RPM auction. The increase consisted of 15 new resources (406.9 MW), four reactivated resources (161.7 MW), three that were previously entirely FRR committed (10.9 MW), one less resource excused from offering (3.9 MW), and one less resource entirely exported (39.9 MW), offset by four deactivated resources (59.6 MW), four resources exported from PJM (554.0 MW), three retired resources (348.4 MW), and two resources excused from offering (108.8 MW). The new resources consisted of seven CT resources (270.5 MW), five new wind resources (120.0 MW), three new diesel resources (16.4 MW), and four reactivated resources (165.0 MW).

In the 2011/2012 auction, 21 more generating resources made offers than in the 2010/2011 RPM auction. The increase consisted of 20 new resources (2,203.7 MW), four reactivated resources (486.9 MW), three fewer excused resources (126.3 MW), and one additional resource imported (663.2 MW), offset by five additional resources committed fully to FRR (1.0 MW) and two retired resources (87.3 MW). The new resources consisted of 11 new CT resources (728.7 MW), four new wind resources (75.2 MW), two new steam resources (838.0 MW), one new combined cycle resource (556.5 MW), one new diesel resource (4.2 MW) and one new solar resource (1.1 MW).

In the 2012/2013 auction, eight more generating resources made offers than in the 2011/2012 RPM auction. The net increase of eight resources consisted of 16 new resources (772.5 MW), four resources that were previously entirely FRR committed (13.4 MW), three additional resources imported (276.8 MW), two additional resources resulting from disaggregation of RPM resources, and one resource formerly unoffered (1.9 MW), offset by nine retired resources (1,044.5 MW), four additional resources committed fully to FRR (39.5 MW), four less resources resulting from aggregation of RPM resources, and one less external resource that did not offer (663.2 MW).[7] In addition, there were the following retirements of resources that were either exported or excused in the 2011/2012 BRA: two CT resources (5.3 MW) and three combined cycle resources (297.6 MW). Also, resources that are no longer PJM capacity resources consisted of three CT units (521.5 MW) in the RTO. The new units consisted of six new diesel resources (13.9 MW), four new wind resources (57.9 MW), three new steam units (560.4 MW), and three new CT units (140.3 MW).

In the 2013/2014 auction, 37 more generation resources made offers than in the 2012/2013 auction. The increase in generating resources consisted of 63 ATSI resources that were not offered in the 2012/2013 BRA (11,325.4 MW), 31 new resources (1,038.2 MW), four resources that were previously entirely Fixed Resource Requirement (FRR) committed (234.3 MW), and four additional resources imported (460.1 MW). The reduction in generating resources consisted of seven retired resources (824.0 MW), two deactivated resources (66.6 MW), 49 additional resources committed fully to FRR (307.7 MW), four less planned generation resources that were not offered (249.3 MW), two additional resources excused from offering (4.2 MW), and one less external resource that was not offered (45.7 MW). In addition, there were the following retirements of resources that were either exported or excused in the 2012/2013 BRA: three steam units (125.9 MW). The new generation capacity resources consisted of 11 solar resources (9.5 MW), 11 wind resources (245.7 MW), four combined cycle units (671.5 MW), three diesel resources (5.4 MW), one steam unit (23.8 MW), and one CT unit (82.3 MW). In addition, there were the following new generation resources that were not offered in to the auction because they were either exported or entirely committed to FRR for the 2013/2014 delivery year: four wind resources (66.2 MW).

- **Demand.** There was a 3,156.7 MW increase in the RPM reliability requirement from 153,480.1 MW on June 1, 2009 to 156,636.8 MW on June 1, 2010. On June 1, 2010, PJM Electric Distribution Companies (EDCs) and their affiliates maintained a 77.7 percent market share of load obligations under RPM, down from 79.6 percent on June 1, 2009.

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

- **Market Concentration.** For the 2010/2011, 2011/2012, 2012/2013, and 2013/2014 RPM Auctions, all defined markets failed the preliminary market structure screen (PMSS). In the 2010/2011 BRA, 2010/2011 Third IA, 2011/2012 BRA, 2011/2012 First IA, 2012/2013 First IA, and 2013/2014 BRA all participants in the total PJM market as well as the locational deliverability area (LDA) markets failed the three pivotal supplier (TPS) market structure test. In the 2012/2013 BRA, all participants in the RTO as well as MAAC, PSEG North, and DPL South RPM markets failed the TPS test. Six participants included in the incremental supply of EMAAC passed the TPS test. Offer caps were applied to all sell offers that did not pass the test.

- **Imports and Exports.** Net exchange decreased 707.2 MW from June 1, 2009 to June 1, 2010. Net exchange, which is imports less exports, decreased due to an increase in exports of 952.5 MW offset by an increase in imports of 245.3 MW.

- **Demand-Side and Energy Efficiency Resources.** Under RPM, demand-side resources in the Capacity Market increased by 1,824.9 MW from 7,374.4 MW on June 1, 2009 to 9,199.3 MW on June 1, 2010. Prior to the 2012/2013 delivery year, demand-side resources included DR cleared in the RPM Auctions and certified/forecast interruptible load for reliability (ILR). For delivery years 2012/2013 and beyond, ILR was eliminated and demand-side resources include DR and EE resources.

- **RPM Net Excess.** RPM net excess decreased 537.5 MW from 8,265.5 MW on June 1, 2009 to 7,728.0 MW on June 1, 2010.

Market Conduct

- **2010/2011 RPM Base Residual Auction.** Of the 1,104 generating resources which submitted offers, unit-specific offer caps were calculated for 154 resources (13.9 percent). Offer caps of all kinds were calculated for 532 resources (48.1 percent), of which 370 were based on the technology specific default (proxy) ACR value.

- **2010/2011 Third Incremental Auction.** Of the 303 generating resources which submitted offers, 193 resources chose the offer cap option of 1.1 times the BRA clearing price (63.7 percent). Unit-specific offer caps were calculated for one resource (0.3 percent). Offer caps of all kinds were calculated for nine resources (2.9 percent), of which seven were based on the technology specific default (proxy) ACR value.

- **2011/2012 RPM Base Residual Auction.** Of the 1,125 generating resources which submitted offers, unit-specific offer caps were calculated for 145 resources (12.9 percent). Offer caps of all kinds were calculated for 470 resources (41.8 percent), of which 301 were based on the technology specific default (proxy) ACR value.

- **2011/2012 RPM First Incremental Auction.** Of the 129 generating resources which submitted offers, unit-specific offer caps were calculated for 19 resources (14.7 percent). Offer caps of all kinds were calculated for 68 resources (52.8 percent), of which 47 were based on the technology specific default (proxy) ACR value.

- **2012/2013 RPM Base Residual Auction.**[8] Of the 1,133 generating resources which submitted offers, unit-specific offer caps were calculated for 120 resources (10.6 percent). Offer caps of all kinds were calculated for 607 resources (53.6 percent), of which 479 were based on the technology specific default (proxy) ACR value.

- **2012/2013 RPM First Incremental Auction.** Of the 162 generating resources which submitted offers, unit-specific offer caps were calculated for 14 resources (8.6 percent). Offer caps of all kinds were calculated for 108 resources (66.6 percent), of which 92 were based on the technology specific default (proxy) ACR value.

- **2013/2014 RPM Base Residual Auction.**[9] Of the 1,170 generating resources which submitted offers, unit-specific offer caps were calculated for 107 resources (9.1 percent). Offer caps of all kinds were calculated for 700 resources (59.9 percent), of which 587 were based on the technology specific default (proxy) ACR value.

Market Performance

2010/2011 RPM Base Residual Auction

- **RTO.** Total internal RTO unforced capacity of 159,030.9 MW includes all generation resources and DR that qualified as a PJM capacity resource for the 2010/2011 RPM Base Residual Auction, excludes external units and reflects owners' modifications to installed capacity (ICAP) ratings. After accounting for FRR committed resources and imports, RPM capacity was 137,360.7 MW. The 132,190.4 MW of

8 For a more detailed analysis of the 2012/2013 RPM Base Residual Auction, see "Analysis of the 2012/2013 RPM Base Residual Auction" (August 6, 2009) <http://www.monitoringanalytics.com/reports/Reports/2009/Analysis_of_2012_2013_RPM_Base_Residual_Auction_20090806.pdf>.

9 For a more detailed analysis of the 2013/2014 RPM Base Residual Auction, see "Analysis of the 2013/2014 RPM Base Residual Auction Revised and Updated" (September 20, 2010) <http://www.monitoringanalytics.com/reports/Reports/2010/Analysis_of_2013_2014_RPM_Base_Residual_Auction_20090920.pdf>.

cleared resources for the entire RTO represented a reserve margin of 16.5 percent, resulted in net excess of 7,728.0 MW over the reliability requirement of 132,698.8 MW (Installed Reserve Margin (IRM) of 15.5 percent), and resulted in a clearing price of $174.29 per MW-day.

Total cleared resources in the RTO were 132,190.4 MW which resulted in a net excess of 7,728.0 MW, a decrease of 537.5 MW from the net excess of 8,265.5 MW in the 2009/2010 RPM BRA. Certified interruptible load for reliability (ILR) was 8,236.4 MW.

Cleared resources across the entire RTO will receive a total of $8.4 billion based on the unforced MW cleared and the prices in the 2010/2011 RPM BRA, an increase of approximately $960.4 million from the 2009/2010 BRA.

- **DPL South.** Total internal DPL South unforced capacity of 1,546.1 MW includes all generation resources and DR that qualified as a PJM capacity resource, excludes external units and reflects owners' modifications to ICAP ratings. All imports offered into the auction are modeled in the RTO, so total DPL South RPM unforced capacity was 1,546.1 MW.[10] All of the 1,519.7 MW cleared in DPL South were cleared in the RTO before DPL South became constrained. Of the 26.4 MW of incremental supply, none cleared, because all 26.4 MW were priced above the demand curve. The DPL South resource clearing price of $186.12 per MW-day was determined by the intersection of the demand curve and a vertical section of the supply curve.

  Total resources in DPL South were 2,966.7 MW, which when combined with certified ILR of 97.2 MW resulted in a net excess of 14.5 MW (0.5 percent) greater than the reliability requirement of 3,049.4 MW.

2010/2011 RPM Third Incremental Auction

- **RTO.** There were 4,553.9 MW offered into the 2010/2011 Third Incremental Auction while buy bids totaled 5,221.0 MW. Cleared volumes in the RTO were 1,845.8 MW, resulting in an RTO clearing price of $50.00 per MW-day. The 2,708.1 MW of uncleared volumes can be used as replacement capacity or traded bilaterally.

  Cleared resources across the entire RTO will receive a total of $33.7 million based on the unforced MW cleared and the prices in the 2010/2011 RPM Third Incremental Auction.

- **DPL South.** Although DPL South was a constrained LDA in the 2010/2011 BRA, supply and demand curves resulted in a price less than the RTO clearing price. Supply offers in the incremental auction in DPL South (56.8 MW) exceeded DPL South demand bids (25.9 MW). The result was that all of DPL South supply which cleared received the RTO clearing price.

Generator Performance

- **Forced Outage Rates.** Average PJM EFORd decreased from 7.4 percent in the first nine months of 2009 to 6.8 percent in the first nine months of 2010. PJM EFORp increased from 4.1 percent in the first nine months of 2009 to 5.0 percent in the first nine months of 2010.[11]

- **Generator Performance Factors.** The PJM aggregate equivalent availability factor decreased from 86.6 percent in the first nine months of 2009 to 86.1 percent in the first nine months of 2010.

- **Outages Deemed Outside Management Control (OMC).** According to NERC criteria, an outage may be classified as an OMC outage only if the generating unit outage was caused by other than failure of the owning company's equipment or other than the failure of the practices, policies and procedures of the owning company. OMC outages are excluded from the calculation of the forced outage rate, termed the XEFORd, used to calculate the unforced capacity that must be offered in the PJM Capacity Market.

Conclusion

The analysis of PJM Capacity Markets begins with market structure, which provides the framework for the actual behavior or conduct of market participants. The analysis examines participant behavior within that market structure. In a competitive market structure, market participants

10 Rules for RPM auctions state that imports are modeled in the unconstrained region of the RTO. See PJM. "Manual 18: PJM Capacity Market," Revision 10 (Effective June 1, 2010), p. 24, <http://www.pjm.com/~/media/documents/manuals/m18.ashx> (1.32 MB).

11 2009 data is for the nine months ended September 30, 2009, as downloaded from the PJM GADS database on October 21, 2010. 2010 data is for the period ending September 30, 2010, as downloaded from the PJM GADS database on October 21, 2010. Annual EFORd data presented in state of the market reports may be revised based on data submitted after the publication of the reports as generation owners may submit corrections at any time with permission from PJM GADS administrators.

are constrained to behave competitively. The analysis examines market performance, measured by price and the relationship between price and marginal cost, that results from the interaction of market structure and participant behavior.

The MMU found serious market structure issues, measured by the three pivotal supplier test results, by market shares and by Herfindahl-Hirschman Index (HHI), but no exercise of market power in the PJM Capacity Market during the first nine months of 2010. Explicit market power mitigation rules in the RPM construct offset the underlying market structure issues in the PJM Capacity Market under RPM. The PJM Capacity Market results were competitive during the first nine months of 2010.

The MMU has also identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[12,13,14,15,16,17]

12 See "Analysis of the 2010/2011 RPM Auction Revised" (July 3, 2008) <http://www.monitoringanalytics.com/reports/Reports/2008/20102011-rpm-review-final-revised.pdf>.
13 See "Analysis of the 2011/2012 RPM Auction Revised" (October 1, 2008) <http://www.monitoringanalytics.com/reports/Reports/2008/20081002-review-of-2011-2012-rpm-auction-revised.pdf>.
14 See "Analysis of the 2012/2013 RPM Base Residual Auction" (August 6, 2009) <http://www.monitoringanalytics.com/reports/Reports/2009/Analysis_of_2012_2013_RPM_Base_Residual_Auction_20090806.pdf>.
15 See "Analysis of the 2013/2014 RPM Base Residual Auction Revised and Updated" (September 20, 2010) <http://www.monitoringanalytics.com/reports/Reports/2010/Analysis_of_2013_2014_RPM_Base_Residual_Auction_20090920.pdf>.
16 See *2009 State of the Market Report for PJM*, Section 5, "Capacity Market" (March 11, 2010).
17 See "IMM Response to Maryland PSC re: Reliability Pricing Model and the 2013/2014 Delivery Year Base Residual Auction Results" (October 4, 2010) <http://www.monitoringanalytics.com/reports/Reports/2010/IMM_Response_to_MDPSC_RPM_and_2013-2014_BRA_Results.pdf>

RPM Capacity Market

Market Structure

Supply

Table 5-1 Internal capacity: June 1, 2009, to June 1, 2013[18]

	UCAP (MW)					
	RTO	MAAC	EMAAC	DPL South	PSEG North	Pepco
Total internal capacity @ 01-Jun-09	157,318.2			1,587.0		
New generation	406.9			0.0		
Units out of retirement	165.0			0.0		
Generation capmods	1,085.8			(85.5)		
DR mods	43.7			15.7		
Net EFORd effect	11.3			28.9		
Total internal capacity @ 01-Jun-10	159,030.9			1,546.1		
New generation	2,203.7					
Units out of retirement	486.9					
Generation capmods	(2,567.6)					
DR mods	684.4					
Net EFORd effect	44.4					
Total internal capacity @ 01-Jun-11	159,882.7	66,329.7	32,733.0	1,460.3	4,167.5	
Reclassification of Duquesne resources	3,187.2	0.0	0.0	0.0	0.0	
Adjusted internal capacity @ 01-Jun-11	163,069.9	66,329.7	32,733.0	1,460.3	4,167.5	
New generation	661.3	61.9	59.7	0.0	0.0	
Units out of retirement	0.0	0.0	0.0	0.0	0.0	
Generation capmods	(1,513.1)	(901.3)	(444.9)	(31.8)	(509.0)	
DR mods	8,028.7	3,829.7	1,480.9	64.6	67.6	
EE mods	652.5	186.9	24.4	0.0	0.9	
Net EFORd effect	(946.0)	(503.0)	(185.6)	5.8	18.3	
Total internal capacity @ 01-Jun-12	169,953.3	69,003.9	33,667.5	1,498.9	3,745.3	5,416.0
Correction in resource modeling	0.0	13.0	0.0			0.0
Adjusted internal capacity @ 01-Jun-12	169,953.3	69,016.9	33,667.5			5,416.0
Integration of existing ATSI resources	13,175.2	0.0	0.0			0.0
New generation	1,104.4	172.5	110.3			1.8
Units out of retirement	0.0	0.0	0.0			0.0
Generation capmods	(969.4)	(1,007.7)	(884.9)			(11.0)
DR mods	1,894.1	900.2	689.5			61.8
EE mods	100.8	(34.9)	(0.3)			(20.7)
Net EFORd effect	(580.2)	31.9	118.5			(159.0)
Total internal capacity @ 01-Jun-13	184,678.2	69,078.9	33,700.6			5,288.9

18 The RTO includes MAAC, EMAAC and SWMAAC. MAAC includes EMAAC and SWMAAC. EMAAC includes DPL South and PSEG North. SWMAAC includes Pepco. Results for only constrained LDAs are shown. Maps of the LDAs can be found in the *2009 State of the Market Report for PJM*, Appendix A, "PJM Geography."

Demand

Table 5-2 PJM Capacity Market load obligation served: June 1, 2010 (See 2009 SOM, Table 5-2)

	Obligation (MW)							
	PJM EDCs	PJM EDC Generating Affiliates	PJM EDC Marketing Affiliates	Non-PJM EDC Generating Affiliates	Non-PJM EDC Marketing Affiliates	Non-EDC Generating Affiliates	Non-EDC Marketing Affiliates	Total
Obligation	66,223.4	12,774.7	24,974.3	1,144.4	12,755.6	567.1	15,408.6	133,848.1
Percent of total obligation	49.5%	9.5%	18.7%	0.9%	9.5%	0.4%	11.5%	100.0%

Market Concentration

Preliminary Market Structure Screen

Table 5-3 Preliminary market structure screen results: 2010/2011 through 2013/2014 RPM Auctions (See 2009 SOM, Table 5-3)

RPM Markets	Highest Market Share	HHI	Pivotal Suppliers	Pass/Fail
2010/2011				
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
2011/2012				
RTO	18.0%	855	1	Fail
2012/2013				
RTO	17.4%	853	1	Fail
MAAC	17.6%	1071	1	Fail
EMAAC	32.8%	2057	1	Fail
SWMAAC	50.7%	4338	1	Fail
PSEG	84.3%	7188	1	Fail
PSEG North	90.9%	8287	1	Fail
DPL South	55.0%	3828	1	Fail
2013/2014				
RTO	14.4%	812	1	Fail
MAAC	18.1%	1101	1	Fail
EMAAC	33.0%	1992	1	Fail
SWMAAC	50.9%	4790	1	Fail
PSEG	89.7%	8069	1	Fail
PSEG North	89.5%	8056	1	Fail
DPL South	55.8%	3887	1	Fail
JCPL	28.5%	1731	1	Fail
Pepco	94.5%	8947	1	Fail

Auction Market Structure

Table 5-4 RSI results: 2010/2011 through 2013/2014 RPM Auctions[19] (See 2009 SOM, Table 5-4)

RPM Markets	RSI_3	Total Participants	Failed RSI_3 Participants
2010/2011 BRA			
RTO	0.60	68	68
DPL South	0.00	2	2
2010/2011 Third IA			
RTO	0.53	47	47
2011/2012 BRA			
RTO	0.63	76	76
2011/2012 First IA			
RTO	0.62	30	30
2012/2013 BRA			
RTO	0.63	98	98
MAAC/SWMAAC	0.54	15	15
EMAAC/PSEG	7.03	6	0
PSEG North	0.00	2	2
DPL South	0.00	3	3
2012/2013 First IA			
RTO	0.60	25	25
EMAAC	0.00	2	2
2013/2014 BRA			
RTO	0.59	87	87
MAAC/SWMAAC	0.23	9	9
EMAAC/PSEG/PSEG North/DPL South	0.00	2	2
Pepco	0.00	1	1

19 The RSI shown is the lowest RSI in the market.

Imports and Exports

Table 5-5 PJM capacity summary (MW): June 1, 2007, to June 1, 2013[20] (See 2009 SOM, Table 5-5)

	01-Jun-07	01-Jun-08	01-Jun-09	01-Jun-10	01-Jun-11	01-Jun-12	01-Jun-13
Installed capacity (ICAP)	163,721.1	164,444.1	166,916.0	168,061.5	172,666.6	181,159.7	197,775.0
Unforced capacity	154,076.7	155,590.2	157,628.7	158,634.2	163,144.3	171,147.8	186,588.0
Cleared capacity	129,409.2	129,597.6	132,231.8	132,190.4	132,221.5	136,143.5	152,743.3
Make-whole	0.0	0.0	0.0	0.0	43.0	222.1	14.0
RPM reliability requirement (pre-FRR)	148,277.3	150,934.6	153,480.1	156,636.8	154,251.1	157,488.5	173,549.0
RPM reliability requirement (less FRR)	125,805.0	128,194.6	130,447.8	132,698.8	130,658.7	133,732.4	149,988.7
RPM net excess	5,240.5	5,011.1	8,265.5	7,728.0	3,199.6	5,976.5	6,518.3
Imports	2,809.2	2,460.3	2,505.4	2,750.7	6,420.0	3,831.6	4,348.2
Exports	(3,938.5)	(3,838.1)	(2,194.9)	(3,147.4)	(3,158.4)	(2,637.1)	(2,438.4)
Net exchange	(1,129.3)	(1,377.8)	310.5	(396.7)	3,261.6	1,194.5	1,909.8
DR cleared	127.6	536.2	892.9	939.0	1,364.9	7,047.2	9,281.9
EE cleared						568.9	679.4
ILR	1,636.3	3,608.1	6,481.5	8,236.4	1,593.8		
FRR DR	445.6	452.8	423.6	452.9	452.9	488.1	488.6
Short-Term Resource Procurement Target						3,343.3	3,749.7

20 Prior to the 2012/2013 delivery year, net excess under RPM was calculated as cleared capacity less the reliability requirement plus ILR. For 2007/2008 through 2010/2011, certified ILR was used in the calculation. Forecast ILR less FRR DR is used in the calculation when ILR was not certified and prior to 2011/2012 because PJM forecast ILR including FRR DR for the first four Base Residual Auctions. PJM forecast ILR excluding FRR DR for 2011/2012, so FRR DR is not subtracted in the calculation for 2011/2012. Net excess calculations for auctions prior to 2010/2011 were originally calculated as cleared capacity less the reliability requirement. For delivery years 2012/2013 and beyond, net excess under RPM is calculated as cleared capacity less the reliability requirement plus the Short-Term Resource Procurement Target.

Demand-Side Resources

Table 5-6 RPM load management statistics: June 1, 2009 to June 1, 2013[21,22] (See 2009 SOM, Table 5-6)

	UCAP (MW)							
	RTO	MAAC+APS	MAAC	EMAAC	SWMAAC	DPL South	PSEG North	Pepco
DR cleared	892.9	813.9			356.3			
ILR certified	6,481.5	1,055.7			345.7			
RPM load management @ 01-June-2009	7,374.4	1,869.6			702.0			
DR cleared	962.9					14.9		
ILR certified	8,236.4					97.2		
RPM load management @ 01-June-2010	9,199.3					112.1		
DR cleared	1,364.9							
ILR forecast	1,593.8							
RPM load management @ 01-June-2011	2,958.7							
DR cleared	7,524.6		4,897.4	1,807.3		66.1	72.2	
EE cleared	568.9		179.9	20.0		0.0	0.9	
RPM load management @ 01-June-2012	8,093.5		5,077.3	1,827.3		66.1	73.1	
DR cleared	9,281.9		5,871.1	2,461.3				547.3
EE cleared	679.4		152.0	23.9				35.8
RPM load management @ 01-June-2013	9,961.3		6,023.1	2,485.2				583.1

21 For delivery years through 2010/2011, certified ILR data were used in the calculation, because the certified ILR data are now available. PJM forecast ILR including FRR DR for the first four Base Residual Auctions. PJM forecast ILR excluding FRR DR for 2011/2012. Effective the 2012/2013 delivery year, ILR was eliminated and the Energy Efficiency (EE) resource type was eligible to be offered in RPM auctions.

22 For 2010/2011, DPL zonal ILR MW are allocated to the DPL South sub-zonal LDA using the sub-zonal load ratio share (57.72 percent for DPL South).

Market Conduct

Offer Caps

Table 5-7 ACR statistics: 2010/2011 through 2011/2012 RPM Auctions (See 2009 SOM, Table 5-7)

	2010/2011 BRA		2010/2011 Third IA		2011/2012 BRA		2011/2012 First IA	
Calculation Type	Number of Resources	Percent of Generation Resources Offered	Number of Resources	Percent of Generation Resources Offered	Number of Resources	Percent of Generation Resources Offered	Number of Resources	Percent of Generation Resources Offered
Default ACR selected	370	33.5%	7	2.3%	299	26.6%	44	34.1%
ACR data input (APIR)	134	12.1%	1	0.3%	133	11.8%	18	14.0%
ACR data input (non-APIR)	20	1.8%	0	0.0%	12	1.1%	1	0.8%
Opportunity cost input	8	0.7%	1	0.3%	24	2.1%	2	1.6%
Default ACR and opportunity cost input	0	0.0%	0	0.0%	2	0.2%	3	2.3%
Generation resources with offer caps	532	48.1%	9	2.9%	470	41.8%	68	52.8%
Uncapped planned generation resources	15	1.4%	0	0.0%	20	1.8%	1	0.8%
Generators with 1.1 times BRA clearing price offer cap	NA		193	63.7%	NA		NA	
Generation price takers	557	50.5%	101	33.4%	635	56.4%	60	46.4%
Generation resources offered	1,104	100.0%	303	100.0%	1,125	100.0%	129	100.0%
Demand resources offered	23		34		37		0	
Energy efficiency resources offered	0		0		0		0	
Total capacity resources offered	1,127		337		1,162		129	

Table 5-8 ACR statistics: 2012/2013 through 2013/2014 RPM Auctions[23] (See 2009 SOM, Table 5-8)

	2012/2013 BRA		2012/2013 First IA		2013/2014 BRA	
Calculation Type	Number of Resources	Percent of Generation Resources Offered	Number of Resources	Percent of Generation Resources Offered	Number of Resources	Percent of Generation Resources Offered
Default ACR selected	465	41.0%	92	56.8%	580	49.6%
ACR data input (APIR)	118	10.4%	14	8.6%	92	7.9%
ACR data input (non-APIR)	2	0.2%	0	0.0%	15	1.3%
Opportunity cost input	8	0.7%	2	1.2%	6	0.5%
Default ACR and opportunity cost input	14	1.2%	0	0.0%	7	0.6%
Generation resources with offer caps	607	53.5%	108	66.6%	700	59.9%
Uncapped planned generation resources	11	1.0%	17	10.5%	20	1.7%
Generators with 1.1 times BRA clearing price offer cap	NA		NA		NA	
Generation price takers	515	45.5%	37	22.9%	450	38.4%
Generation resources offered	1,133	100.0%	162	100.0%	1,170	100.0%
Demand resources offered	233		77		426	
Energy efficiency resources offered	53		3		128	
Total capacity resources offered	1,419		242		1,724	

23 The ACR statistics have been updated since the MMU RPM Auction reports were posted.

Table 5-9 APIR statistics: 2010/2011 through 2013/2014 RPM Auctions[24,25,26,27] (See 2009 SOM, Table 5-9)

		Weighted-Average ($ per MW-day UCAP)					
		Combined Cycle	Combustion Turbine	Oil or Gas Steam	Subcritical/ Supercritical Coal	Other	Total
2010/2011 BRA							
Non-APIR units	ACR	$34.39	$27.10	$67.57	$167.08	$82.55	$80.86
	Net revenues	$96.75	$18.81	$15.19	$302.79	$391.00	$151.31
	Offer caps	$10.13	$14.12	$52.38	$9.67	$4.53	$11.94
APIR units	ACR	$61.61	$49.26	$152.09	$654.18	$34.62	$360.27
	Net revenues	$26.84	$10.32	$20.94	$525.48	$2.07	$263.27
	Offer caps	$37.30	$39.41	$131.15	$155.39	$32.55	$110.25
	APIR	$9.87	$30.93	$60.54	$521.16	$22.42	$272.18
	Maximum APIR effect						$577.03
2011/2012 BRA							
Non-APIR units	ACR	$39.52	$30.17	$72.20	$181.52	$62.54	$75.61
	Net revenues	$69.04	$20.16	$17.27	$466.41	$322.78	$169.93
	Offer caps	$11.76	$16.42	$62.13	$7.88	$11.50	$17.64
APIR units	ACR	$61.66	$56.28	$184.34	$723.65	$36.03	$424.49
	Net revenues	$78.17	$10.35	$19.81	$531.93	$2.06	$286.80
	Offer caps	$34.69	$46.18	$164.54	$203.41	$33.97	$147.77
	APIR	$11.82	$37.28	$91.30	$578.47	$24.68	$324.58
	Maximum APIR effect						$523.26
2011/2012 First IA							
Non-APIR units	ACR	$54.15	$29.43	NA	$284.63	$30.04	$169.77
	Net revenues	$220.31	$44.98	NA	$298.96	$0.07	$195.83
	Offer caps	$2.66	$2.64	NA	$150.63	$29.97	$83.01
APIR units	ACR	$220.20	$152.28	$194.25	$583.59	NA	$326.57
	Net revenues	$81.72	$6.94	$23.64	$328.71	NA	$128.90
	Offer caps	$138.48	$145.34	$170.62	$254.88	NA	$197.67
	APIR	$220.19	$120.84	$82.87	$324.31	NA	$170.61
	Maximum APIR effect						$468.26

24 The weighted-average offer cap can be positive even when the weighted-average net revenues are higher than the weighted-average ACR due to the offer cap minimum being zero. On a unit basis, if net revenues are greater than ACR, the offer cap is zero.
25 This table has been updated since the MMU RPM Auction reports were posted. The 2010/2011 and 2011/2012 BRA values for Oil and Gas Steam and Sub Critical/Super Critical Coal for resources with an APIR component were updated due to a prior misclassification.
26 For reasons of confidentiality, the APIR statistics do not include opportunity cost based offer cap data.
27 Statistics for the 2010/2011 Third IA are not included as the majority of the resources chose the offer cap option of 1.1 times the BRA clearing price.

Table 5-9 APIR statistics: 2010/2011 through 2013/2014 RPM Auctions (See 2009 SOM, Table 5-9) [continued]

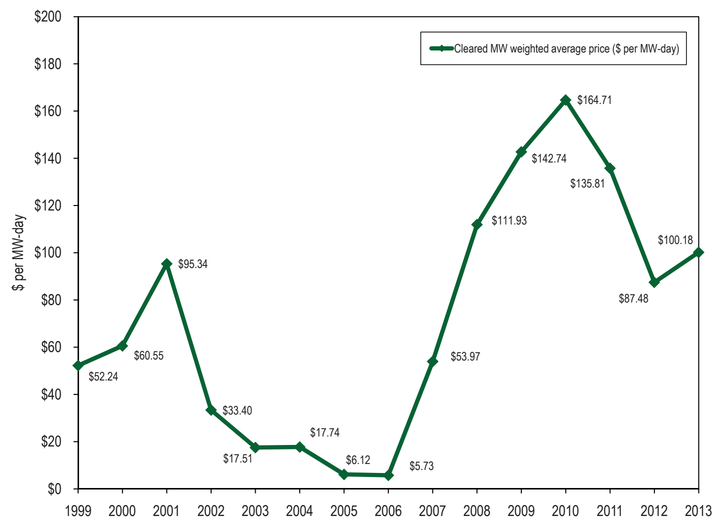
		Weighted-Average ($ per MW-day UCAP)					
		Combined Cycle	Combustion Turbine	Oil or Gas Steam	Subcritical/ Supercritical Coal	Other	Total
2012/2013 BRA							
Non-APIR units	ACR	$41.84	$32.61	$75.47	$207.54	$57.18	$110.84
	Net revenues	$91.67	$35.29	$7.51	$396.82	$257.96	$208.65
	Offer caps	$5.28	$14.40	$67.96	$11.31	$15.63	$13.74
APIR units	ACR	$218.10	$49.83	$177.52	$715.10	NA	$464.65
	Net revenues	$98.97	$15.62	$3.62	$508.00	NA	$302.04
	Offer caps	$119.12	$34.96	$173.89	$215.38	NA	$167.62
	APIR	$218.10	$26.59	$89.08	$559.97	NA	$351.74
	Maximum APIR effect						$1,155.57
2012/2013 First IA							
Non-APIR units	ACR	$69.71	$30.49	$86.40	$229.86	$32.75	$67.26
	Net revenues	$136.19	$5.75	$12.73	$156.50	$33.52	$30.71
	Offer caps	$32.88	$24.75	$73.67	$75.99	$27.72	$37.81
APIR units	ACR	NA	$50.56	$289.38	$660.56	NA	$367.75
	Net revenues	NA	$9.15	$50.16	$434.48	NA	$138.16
	Offer caps	NA	$41.40	$239.21	$226.09	NA	$229.59
	APIR	NA	$7.70	$156.87	$459.80	NA	$222.35
	Maximum APIR effect						$549.57
2013/2014 BRA							
Non-APIR units	ACR	$44.51	$33.30	$79.91	$212.68	$52.57	$115.83
	Net revenues	$110.63	$30.53	$12.72	$364.90	$259.34	$199.44
	Offer caps	$6.84	$16.36	$68.15	$9.29	$14.30	$14.09
APIR units	ACR	NA	$49.42	$341.77	$509.95	$305.48	$390.05
	Net revenues	NA	$9.18	$63.80	$459.41	$187.40	$292.92
	Offer caps	NA	$40.73	$277.96	$112.30	$118.09	$134.44
	APIR	NA	$25.28	$243.47	$352.55	$1.69	$268.59
	Maximum APIR effect						$1,304.36

Market Performance

Table 5-10 Capacity prices: 2007/2008 through 2013/2014 RPM Auctions (See 2009 SOM, Table 5-10)

	RPM Clearing Price ($ per MW-day)							
	RTO	MAAC	APS	EMAAC	SWMAAC	DPL South	PSEG North	Pepco
2007/2008 BRA	$40.80	$40.80	$40.80	$197.67	$188.54	$197.67	$197.67	$188.54
2008/2009 BRA	$111.92	$111.92	$111.92	$148.80	$210.11	$148.80	$148.80	$210.11
2008/2009 Third IA	$10.00	$10.00	$10.00	$10.00	$223.85	$10.00	$10.00	$223.85
2009/2010 BRA	$102.04	$191.32	$191.32	$191.32	$237.33	$191.32	$191.32	$237.33
2009/2010 Third IA	$40.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00
2010/2011 BRA	$174.29	$174.29	$174.29	$174.29	$174.29	$186.12	$174.29	$174.29
2010/2011 Third IA	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00
2011/2012 BRA	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00
2011/2012 First IA	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00
2011/2012 ATSI FRR Integration Auction	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89
2012/2013 BRA	$16.46	$133.37	$16.46	$139.73	$133.37	$222.30	$185.00	$133.37
2012/2013 ATSI FRR Integration Auction	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46
2012/2013 First IA	$16.46	$16.46	$16.46	$153.67	$16.46	$153.67	$153.67	$16.46
2013/2014 BRA	$27.73	$226.15	$27.73	$245.00	$226.15	$245.00	$245.00	$247.14

Figure 5-1 History of capacity prices: Calendar year 1999 through 2013[28] (See 2009 SOM, Figure 5-1)



28 1999-2006 capacity prices are CCM combined market, weighted average prices. The 2007 capacity price is a combined CCM/RPM weighted average price. The 2008-2013 capacity prices are RPM weighted average prices.

Table 5-11 RPM cost to load: 2010/2011 through 2013/2014 RPM Auctions[29,30,31] (See 2009 SOM, Table 5-11)

	Net Load Price ($ per MW-day)	UCAP Obligation (MW)	Annual Charges
2010/2011 BRA			
RTO	$182.85	129,332.6	$8,631,690,057
DPL	$187.04	4,515.5	$308,271,379
2011/2012 BRA			
RTO	$110.04	133,815.3	$5,389,363,034
2012/2013 BRA			
RTO	$16.46	69,648.3	$418,440,022
MAAC	$129.63	31,338.7	$1,482,789,024
EMAAC	$135.18	21,171.5	$1,044,616,630
DPL	$162.99	4,685.6	$278,752,670
PSEG	$149.65	12,642.7	$690,572,720
2013/2014 BRA			
RTO	$27.73	85,918.0	$869,614,741
MAAC	$223.85	23,944.0	$1,956,350,506
EMAAC	$240.41	38,634.3	$3,390,146,303
Pepco	$236.93	7,996.7	$691,550,218

29 The annual charges are calculated using the rounded, net load prices as posted by PJM.
30 There is no separate obligation for DPL South as the DPL South LDA is completely contained within the DPL Zone. There is no separate obligation for PSEG North as the PSEG North LDA is completely contained within the PSEG Zone.
31 Prior to the 2009/2010 delivery year, the Final UCAP Obligation is determined after the clearing of the Second IA. For the 2009/2010 through 2011/2012 delivery years, the Final UCAP Obligations are determined after the clearing of the Third IA. Effective with the 2012/2013 delivery year, the Final UCAP Obligation is determined after the clearing of the final incremental auction. Prior to the 2012/2013 delivery year, the Final Zonal Capacity Prices are determined after certification of ILR. Effective with the 2012/2013 delivery year, the Final Zonal Capacity Prices are determined after the final incremental auction. The 2011/2012, 2012/2013, and 2013/2014 Net Load Prices and UCAP Obligation MW are not finalized.

2010/2011 RPM Base Residual Auction

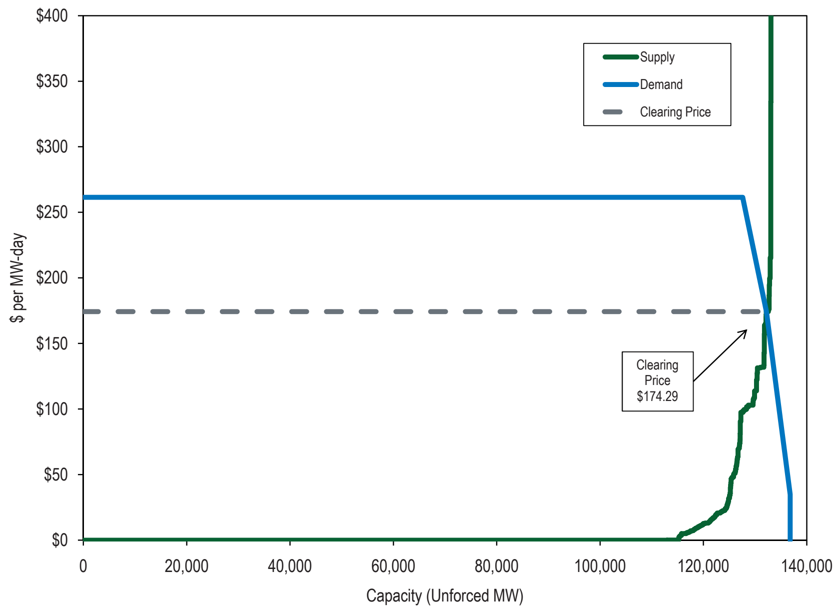
RTO

Table 5-12 RTO offer statistics: 2010/2011 RPM Base Residual Auction[32] (See Analysis of the 2010/2011 RPM Auction Revised)

	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%
Make-whole	0.0	0.0	0.0%	0.0%
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 plus make-whole		132,190.4		
ILR certified		8,236.4		
Net excess/(deficit)		7,728.0		
Resource clearing price ($ per MW-day)		$174.29	A	
Final zonal capacity price ($ per MW-day)		$182.85	B	
Final zonal CTR credit rate ($ per MW-day)		$0.00	C	
Final zonal ILR price ($ per MW-day)		$174.29	A-C	
Net load price ($ per MW-day)		$182.85	B-C	

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

Figure 5-2 RTO market supply/demand curves: 2010/2011 RPM Base Residual Auction[33] (See Analysis of the 2010/2011 RPM Auction Revised)



33 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.

DPL South

Table 5-13 DPL South offer statistics: 2010/2011 RPM Base Residual Auction[34] (See Analysis of the 2010/2011 RPM Auction Revised)

	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%
Make-whole	0.0	0.0	0.0%	0.0%
Uncleared	26.7	26.4	1.6%	1.7%
Reliability requirement		3,049.4		
Total cleared plus make-whole		1,519.7		
CETL		1,447.0		
Total resources		2,966.7		
ILR certified		97.2		
Net excess/(deficit)		14.5		
Resource clearing price ($ per MW-day)		$186.12		
DPL zone weighted average resource clearing price ($ per MW-day)		$178.57	A	
Final zonal capacity price ($ per MW-day)		$187.34	B	
Final zonal CTR credit rate ($ per MW-day)		$0.30	C	
Final zonal ILR price ($ per MW-day)		$178.27	A-C	
Net load price ($ per MW-day)		$187.04	B-C	

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

2010/2011 RPM Third Incremental Auction

RTO

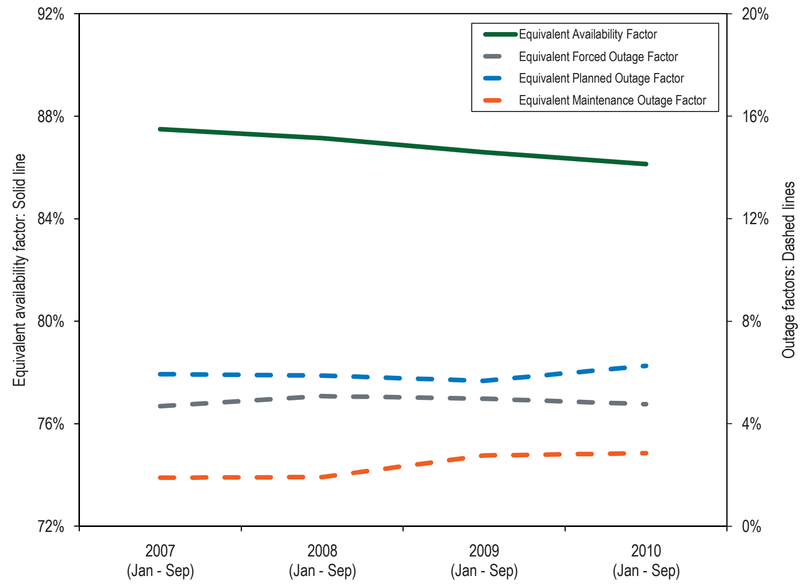
Table 5-14 RTO offer statistics: 2010/2011 RPM Third Incremental Auction (New table)

	Offered (Supply)		Bid (Demand)
	ICAP (MW)	UCAP (MW)	UCAP (MW)
Generation	3,274.3	3,102.3	
DR	1,402.9	1,451.6	
Total	4,677.2	4,553.9	5,221.0
Cleared in RTO	1,947.6	1,845.8	1,845.8
Cleared in LDAs	0.0	0.0	0.0
Total cleared	1,947.6	1,845.8	1,845.8
Uncleared in RTO	2,729.6	2,708.1	3,375.2
Uncleared in LDAs	0.0	0.0	0.0
Total uncleared	2,729.6	2,708.1	3,375.2
Resource clearing price ($ per MW-day)		$50.00	

Generator Performance

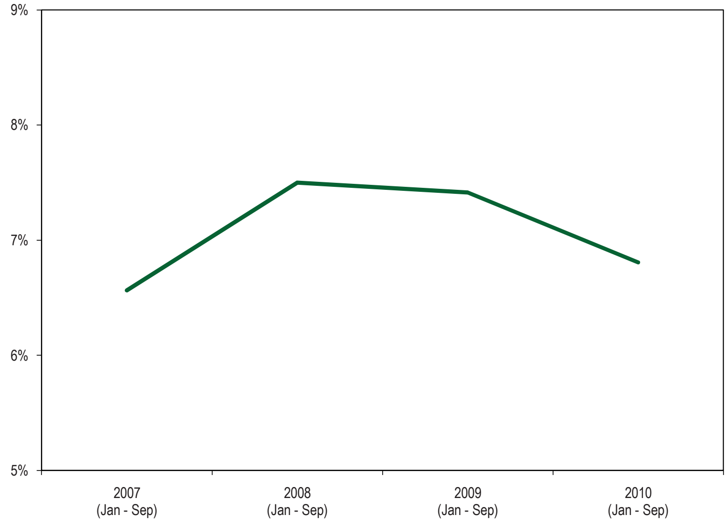
Generator Performance Factors

Figure 5-3 PJM equivalent outage and availability factors: 2007 to 2010 (January through September) (See 2009 SOM, Figure 5-7)



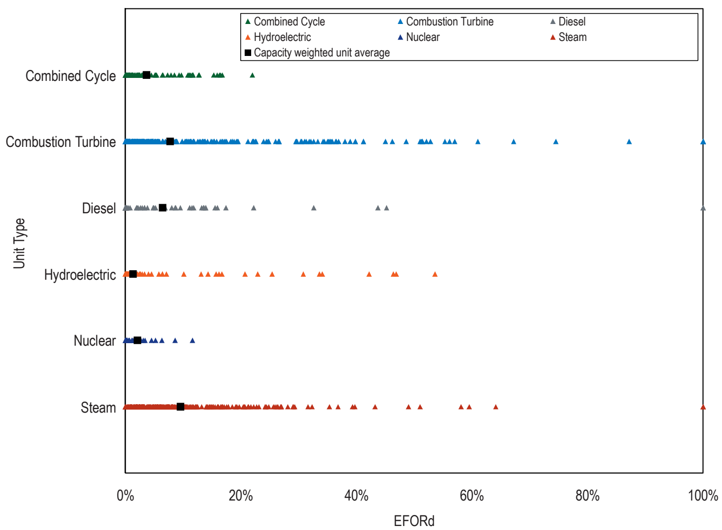
Generator Forced Outage Rates

Figure 5-4 Trends in the PJM equivalent demand forced outage rate (EFORd): 2007 to 2010 (January through September) (See 2009 SOM, Figure 5-8)



Distribution of EFORd

Figure 5-5 PJM 2010 (January through September) Distribution of EFORd data by unit type (See 2009 SOM, Figure 5-9)



Components of EFORd

Table 5-15 PJM EFORd data for different unit types: 2007 to 2010 (January through September) (See 2009 SOM, Table 5-17)

	2007 (Jan - Sep)	2008 (Jan - Sep)	2009 (Jan - Sep)	2010 (Jan - Sep)
Combined Cycle	3.3%	3.5%	4.5%	3.7%
Combustion Turbine	10.6%	10.5%	8.3%	7.8%
Diesel	13.4%	11.7%	9.3%	6.5%
Hydroelectric	2.0%	2.5%	2.7%	1.3%
Nuclear	1.2%	1.0%	4.3%	2.1%
Steam	8.6%	10.4%	9.4%	9.5%
Total	6.6%	7.5%	7.4%	6.8%

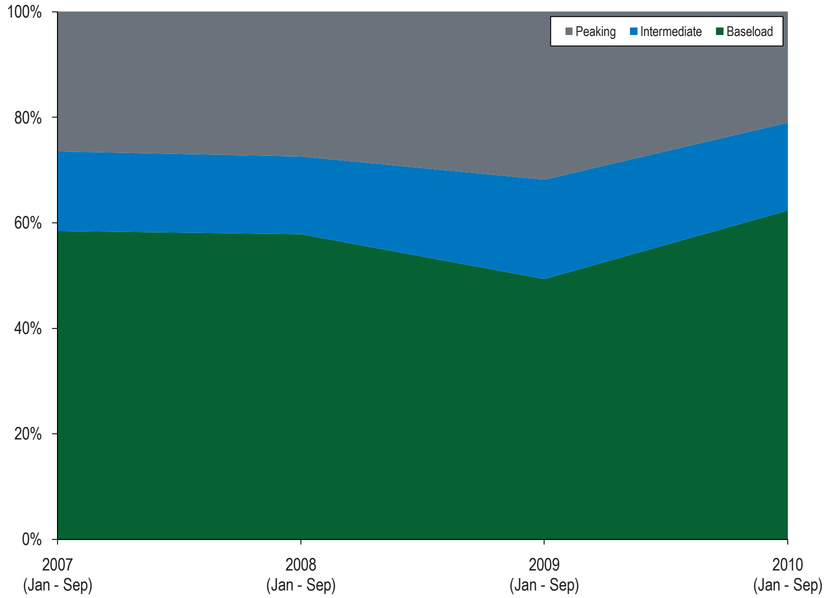
Table 5-16 Contribution to EFORd for specific unit types (Percentage points): 2007 to 2010 (January through September)[35] (See 2009 SOM, Table 5-18)

	2007 (Jan - Sep)	2008 (Jan - Sep)	2009 (Jan - Sep)	2010 (Jan - Sep)
Combined Cycle	0.4	0.4	0.5	0.4
Combustion Turbine	1.6	1.6	1.3	1.2
Diesel	0.0	0.0	0.0	0.0
Hydroelectric	0.1	0.1	0.1	0.1
Nuclear	0.2	0.2	0.8	0.4
Steam	4.2	5.2	4.7	4.7
Total	6.6	7.5	7.4	6.8

35 Calculated values presented in Section 5, "Capacity Market" at "Generator Performance" are based on unrounded, underlying data and may differ from those derived from the rounded values shown in the tables.

Duty Cycle and EFORd

Figure 5-6 Contribution to EFORd by duty cycle: 2007 to 2010 (January through September) (See 2009 SOM, Figure 5-10)



Forced Outage Analysis

Table 5-17 Outage cause contribution to PJM EFOF: Calendar year 2010 (January through September) (See 2009 SOM, Table 5-19)

	Percentage Point Contribution to EFOF	Contribution to EFOF
Boiler Tube Leaks	1.15	23.2%
Economic	0.46	9.2%
Electrical	0.29	5.9%
Boiler Air and Gas Systems	0.29	5.8%
Boiler Internals and Structures	0.25	5.0%
Boiler Fuel Supply from Bunkers to Boiler	0.19	3.7%
Circulating Water Systems	0.16	3.2%
Catastrophe	0.15	3.0%
Feedwater System	0.14	2.9%
Condensing System	0.14	2.8%
Stack Emission	0.11	2.2%
Boiler Piping System	0.10	2.1%
Fuel Quality	0.10	2.0%
Auxiliary Systems	0.09	1.7%
Controls	0.08	1.6%
Boiler Tube Fireside Slagging or Fouling	0.08	1.6%
Exciter	0.08	1.6%
Valve	0.06	1.3%
High Pressure Turbine	0.06	1.2%
All Other Causes	1.00	20.1%
Total	4.97	100.0%

Table 5-18 Contributions to Economic Outages: 2010 (January through September) (See 2009 SOM, Table 5-20)

	Contribution to Economic Reasons
Lack of Fuel (OMC)	74.0%
Other Economic Problems	20.6%
Lack of Fuel (Non-OMC)	4.4%
Lack of Water (Hydro)	0.8%
Fuel Conservation	0.2%
Ground Water or Other Water Supply Problems	0.0%
Total	100.0%

Table 5-19 Contribution to EFOF by unit type for the most prevalent causes: Calendar year 2010 (January through September) (See 2009 SOM, Table 5-21)

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	System
Boiler Tube Leaks	0.4%	0.0%	0.0%	0.0%	0.0%	28.7%	23.2%
Economic	0.5%	26.5%	11.4%	11.5%	0.0%	9.6%	9.2%
Electrical	11.2%	30.6%	3.3%	14.2%	13.4%	3.3%	5.9%
Boiler Air and Gas Systems	0.0%	0.0%	0.0%	0.0%	0.0%	7.1%	5.8%
Boiler Internals and Structures	0.4%	0.0%	0.0%	0.0%	0.0%	6.1%	5.0%
Boiler Fuel Supply from Bunkers to Boiler	0.0%	0.0%	0.0%	0.0%	0.0%	4.6%	3.7%
Circulating Water Systems	1.7%	0.0%	0.0%	0.0%	20.9%	1.9%	3.2%
Catastrophe	0.4%	0.8%	0.6%	8.2%	0.0%	3.5%	3.0%
Feedwater System	2.6%	0.0%	0.0%	0.0%	9.0%	2.5%	2.9%
Condensing System	1.2%	0.0%	0.0%	0.0%	12.0%	2.3%	2.8%
Stack Emission	0.0%	0.0%	0.3%	0.0%	0.0%	2.7%	2.2%
Boiler Piping System	4.4%	0.0%	0.0%	0.0%	0.0%	2.3%	2.1%
Fuel Quality	0.2%	0.0%	1.0%	0.0%	0.0%	2.5%	2.0%
Auxiliary Systems	2.4%	5.9%	0.0%	0.9%	12.4%	0.5%	1.7%
Controls	1.2%	1.1%	0.8%	3.4%	1.6%	1.7%	1.6%
Boiler Tube Fireside Slagging or Fouling	0.0%	0.0%	0.0%	0.0%	0.0%	2.0%	1.6%
Exciter	1.8%	1.3%	0.0%	3.3%	0.0%	1.7%	1.6%
Valve	3.8%	0.0%	0.0%	0.0%	0.1%	1.2%	1.3%
High Pressure Turbine	0.0%	0.0%	0.0%	0.0%	0.0%	1.5%	1.2%
All Other Causes	67.6%	33.9%	82.6%	58.5%	30.5%	14.2%	20.1%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Table 5-20 Contribution to EFOF by unit type: Calendar year 2010 (January through September) (See 2009 SOM, Table 5-22)

	EFOF	Contribution to EFOF
Combined Cycle	2.6%	6.3%
Combustion Turbine	1.5%	4.8%
Diesel	4.5%	0.2%
Hydroelectric	0.7%	0.7%
Nuclear	1.9%	7.1%
Steam	7.7%	80.8%
Total	4.8%	100.0%

Outages Deemed Outside Management Control

Table 5-21 PJM EFORd vs. XEFORd: Calendar year 2010 (January through September) (See 2009 SOM, Table 5-23)

	2010 EFORd	2010 XEFORd	Difference
Combined Cycle	3.7%	3.6%	0.1%
Combustion Turbine	7.8%	5.8%	1.9%
Diesel	6.5%	4.4%	2.0%
Hydroelectric	1.3%	1.0%	0.3%
Nuclear	2.1%	2.1%	0.0%
Steam	9.5%	8.2%	1.4%
Total	6.8%	5.8%	1.0%

Components of EFORp

Table 5-22 Contribution to EFORp by unit type (Percentage points): 2009 to 2010 (January through September[36]) (See 2009 SOM, Table 5-24)

	2009 (Jan - Sep)	2010 (Jan - Sep)
Combined Cycle	0.4	0.3
Combustion Turbine	0.4	0.4
Diesel	0.0	0.0
Hydroelectric	0.1	0.0
Nuclear	0.8	0.5
Steam	2.3	3.8
Total	4.1	5.0

Table 5-23 PJM EFORp data by unit type: 2009 to 2010 (January through September[37]) (See 2009 SOM, Table 5-25)

	2009 (Jan - Sep)	2010 (Jan - Sep)
Combined Cycle	3.4%	2.8%
Combustion Turbine	2.4%	2.3%
Diesel	4.7%	3.6%
Hydroelectric	2.9%	1.1%
Nuclear	4.2%	2.9%
Steam	4.7%	7.6%
Total	4.1%	5.0%

36 EFORp is only calculated for the peak months of January, February, June, July, and August.
37 EFORp is only calculated for the peak months of January, February, June, July, and August.

EFORd, XEFORd and EFORp

Table 5-24 Contribution to PJM EFORd, XEFORd and EFORp by unit type: Calendar year 2010 (January through September[38]) (See 2009 SOM, Table 5-26)

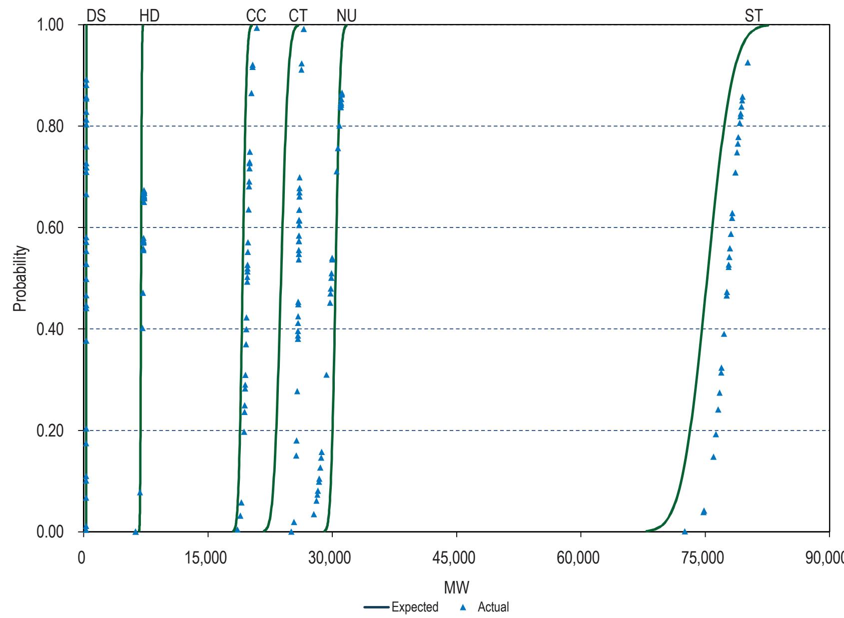
	EFORd	XEFORd	EFORp
Combined Cycle	0.4	0.4	0.3
Combustion Turbine	1.2	0.9	0.4
Diesel	0.0	0.0	0.0
Hydroelectric	0.1	0.0	0.0
Nuclear	0.4	0.4	0.5
Steam	4.7	4.0	3.8
Total	6.8	5.8	5.0

Table 5-25 PJM EFORd, XEFORd and EFORp data by unit type: Calendar year 2010 (January through September[39]) (See 2009 SOM, Table 5-27)

	EFORd	XEFORd	EFORp
Combined Cycle	3.7%	3.6%	2.8%
Combustion Turbine	7.8%	5.8%	2.3%
Diesel	6.5%	4.4%	3.6%
Hydroelectric	1.3%	1.0%	1.1%
Nuclear	2.1%	2.1%	2.9%
Steam	9.5%	8.2%	7.6%
Total	6.8%	5.8%	5.0%

Comparison of Expected and Actual Performance

Figure 5-7 PJM 2010 (January through September) distribution of EFORd data by unit type (See 2009 SOM, Figure 5-11)



38 EFORp is only calculated for the peak months of January, February, June, July, and August.
39 EFORp is only calculated for the peak months of January, February, June, July, and August.

Performance During Peak Months

Figure 5-8 PJM EFORd, XEFORd and EFORp for the peak months of January, February, June, July and August: 2010 (See 2009 SOM, Figure 5-12)

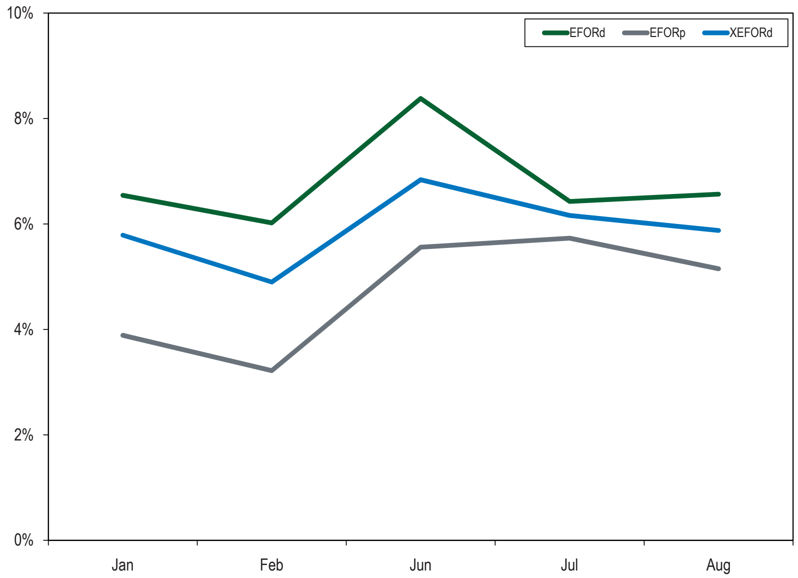


Figure 5-9 PJM peak month generator performance factors: 2010 (See 2009 SOM, Figure 5-13)