SECTION 5 – CAPACITY MARKET

Each organization serving PJM load must meet its capacity obligations through the PJM Capacity Market, where load serving entities (LSEs) must pay the locational capacity price for their zone. LSEs can hedge their financial obligations 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.

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

Table 5-1 The Capacity Market results were competitive

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Not Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior: Local Market	Competitive	
Market Performance	**Competitive**	**Mixed**

- The aggregate market structure was evaluated as not competitive. The entire PJM region failed the preliminary market structure screen (PMSS), which is conducted by the MMU prior to each Base Residual Auction, for every planning year for which it was completed. For almost all auctions held, the PJM region failed the Three Pivotal Supplier Test (TPS), which is conducted at the time of the auction.

- The local market structure was evaluated as not competitive. All modeled Locational Deliverability Areas (LDAs) failed the preliminary market structure screen (PMSS), which is conducted by the MMU prior to each Base Residual Auction, for every planning year for which it was completed. For almost every auction held, all LDAs failed the Three Pivotal Supplier Test (TPS), which is conducted at the time of the auction.

- Participant behavior was evaluated as competitive. Market power mitigation measures were applied when the capacity market seller failed the market power test for the auction and the submitted sell offer exceeded the defined offer cap.

- Market performance was evaluated as competitive. Although structural market power exists in the Capacity Market, a competitive outcome resulted from the application of market power mitigation rules.

- Market design was evaluated as mixed because while there are many positive features of the Reliability Pricing Model (RPM) design, there are several features of the RPM design which threaten competitive outcomes. These include the 2.5 percent reduction in demand in Base Residual Auctions, a definition of DR which permits an inferior product to substitute for capacity and inadequate rules to address buyer side market power.

Highlights

- The 2011/2012 Third Incremental Auction was run in the first quarter of 2011. The RTO resource clearing price in the 2011/2012 RPM Third Incremental Auction was $5.00 per MW-day, a decrease of $40.00 per MW-day from the 2010/2011 RPM Third Incremental Auction resource clearing price.

- All LDAs and the entire PJM Region failed the preliminary market structure screen (PMSS) for the 2014/2015 delivery year.

- Capacity in the RPM load management programs totals 10,810.1 MW for June 1, 2011.

- Annual weighted average capacity prices increased from a Capacity Credit Market (CCM) weighted average price of $5.73 per MW-day in 2006 to an RPM weighted-average price of $164.71 per MW-day in 2010 and then declined to $100.26 per MW-day in 2013.

- The average PJM equivalent demand forced outage rate (EFORd) increased from 6.9 percent in the first three months of 2010 to 8.0 percent in the first three months of 2011.
- The PJM aggregate equivalent availability factor (EAF) decreased from 87.4 percent in the first three months of 2010 to 85.9 percent in the first three months of 2011. The equivalent maintenance outage factor (EMOF) increased from 2.3 percent in the first three months of 2010 to 2.7 percent in the first three months of 2011, the equivalent planned outage factor (EPOF) remained constant at 6.3 percent from the first three months of 2010 to the first three months of 2011, and the equivalent forced outage factor (EFOF) increased from 4.0 percent in the first three months of 2010 to 5.2 percent in the first three months of 2011.

Summary Recommendations

- In this *2011 State of the Market Report for PJM: January through March*, the recommendations from the *2010 State of the Market Report for PJM* remain MMU recommendations.

Overview

RPM Capacity Market

Market Design

The Reliability Pricing Model (RPM) Capacity Market 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.[1]

Under RPM, capacity obligations are annual. Base Residual Auctions (BRA) 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 that 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.** Offered MW in the 2011/2012 RPM Third Incremental Auction totaled 6,537.8 MW. The offered volumes came from uncleared internal generation offers from the 2011/2012 BRA (1,425.5 MW), new generation (283.0 MW), capacity modifications (cap mods) to existing generation resources (181.5 MW), additional UCAP due to improved EFORds since the BRA (1,829.7 MW), net replacements (-235.3 MW), locational UCAP transactions (-1,149.8 MW), ATSI integration generation (866.5 MW), imports (80.8 MW), DR offers (4,179.2 MW), EE offers (90.5 MW) less cleared capacity in the 2011/2012 First Incremental Auction (119.1 MW), ATSI FRR capacity plan commitments

1 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in the *2011 Quarterly State of the Market Report for PJM: January through March*, Section 5, "Capacity Market" and include all capacity within the PJM footprint.
2 See 126 FERC ¶ 61,275 (2009) at P 86.
3 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).
4 See 126 FERC ¶ 61,275 (2009) at P 88.
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.

(853.0 MW), Duquesne FRR capacity plan commitments (48.5 MW), a net change in FRR commitments (57.2 MW), a net change in exports (-18.4 MW), a net change in unoffered MW in the 2011/2012 BRA (-46.9 MW), and excused generation (1.3 MW).

- **Demand.** Buy bids in the 2011/2012 RPM Third Incremental Auction totaled 8,865.2 MW. Buy bids were submitted to cover short positions due to deratings and EFORd increases or because participants wanted to purchase additional capacity.

- **Market Concentration.** For the 2014/2015 delivery year, all defined markets failed the preliminary market structure screen (PMSS).[6] As a result, all capacity market sellers owning or controlling any generation capacity resource located in the entire PJM Region shall be required to provide the information specified in Section 6.7(b) of Attachment DD of the PJM Open Access Transmission Tariff (OATT). In the 2011/2012 Third Incremental Auction all participants in the total PJM market failed the three pivotal supplier (TPS) market structure test.[7,8] Offer caps were applied to all sell offers for resources which were subject to mitigation submitted by capacity market sellers that did not pass the test.[9,10,11]

- **Demand-Side and Energy Efficiency Resources.** Demand-side resources include demand resources (DR) and energy efficiency (EE) resources cleared in RPM auctions and certified/forecast interruptible load for reliability (ILR). Effective with the 2012/2013 delivery year, ILR was eliminated. Starting with the 2012/2013 delivery year and also for incremental auctions in the 2011/2012 delivery year, the energy efficiency resource type is eligible to be offered in RPM auctions.[12] Of the 1,557.0 MW of cleared capacity in the 2011/2012 RPM Third Incremental Auction, 461.7 MW were DR offers and 76.4 MW were EE offers.

Market Conduct

- **2011/2012 RPM Third Incremental Auction.** Of the 398 generation resources which submitted offers, 214 resources elected the offer cap option of 1.1 times the BRA clearing price (53.8 percent). Unit-specific offer caps were calculated for no resources (0.0 percent). Offer caps of all kinds were calculated for 23 resources (5.8 percent), of which 21 were based on the technology specific default (proxy) avoidable cost rate (ACR) values. This was the first RPM Auction conducted under the revised RPM rules regarding mitigation and the definition of planned generation.[13]

Market Performance

2011/2012 RPM Third Incremental Auction

- **RTO.** There were 6,537.8 MW offered into the 2011/2012 Third Incremental Auction while buy bids totaled 8,865.2 MW. Cleared volumes in the RTO were 1,557.0 MW, resulting in an RTO clearing price of $5.00 per MW-day. The 4,980.8 MW of uncleared volumes can be used as replacement capacity or traded bilaterally.

  Cleared capacity resources across the entire RTO will receive a total of $2.8 million based on the unforced MW cleared and the prices in the 2011/2012 RPM Third Incremental Auction.

Generator Performance

- **Forced Outage Rates.** Average PJM EFORd increased from 6.9 percent in the first three months of 2010 to 8.0 percent in the first three months of 2011. PJM Peak-Period Equivalent Forced Outage Rate Peak (EFORp) increased from 3.7 percent in the first three months of 2010 to 4.6 percent in the first three months of 2011.[14]

- **Generator Performance Factors.** The PJM aggregate equivalent availability factor decreased from 87.4 percent in 2010 to 85.9 percent in 2011.

- **Outages Deemed Outside Management Control (OMC).** According to North American Electric Reliability Corporation (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

6 See "Preliminary Market Structure Screen Results for 2014/2015 RPM Base Residual Auction" (February 1, 2011) <http://www.monitoringanalytics.com/reports/Reports/2011/PMSS_Results_20142015_20110201.pdf>.
7 Currently, there are 23 locational deliverability areas (LDAs) identified to recognize locational constraints as defined in "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region", Schedule 10.1. PJM determines, in advance of each BRA, whether the defined LDAs will be modeled in the given delivery year using the rules defined in OATT Attachment DD (Reliability Pricing Model) § 5.10(a)(ii).
8 PJM did not model any LDAs as constrained for the 2011/2012 delivery year.
9 OATT Attachment DD (Reliability Pricing Model) § 6.5.
10 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 (2009) at P 30.
11 The definition of planned generation capacity resource and the rules regarding mitigation were redefined effective January 31, 2011. See 134 FERC ¶ 61,065 (2011).
12 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).
13 See 134 FERC ¶ 61,065 (2011).
14 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM Generator Availability Data Systems (GADS) database. This set of capacity resources may include generators in addition to those in the set of generators committed as resources in the RPM. Data is for the three months ending March 31, as downloaded from the PJM GADS database on April 21, 2011. 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.

procedures of the owning company. In the first three months of 2011, 10.8 percent of forced outages are classified as OMC outages. 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 Capacity Market is, by design, always tight in the sense that total supply is generally only slightly larger than demand. 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. The market may be long at times, but that is not the equilibrium state. Capacity in excess of demand is not sold and, if it does not earn adequate revenues in other markets, will retire. Demand is almost entirely inelastic, because the market rules require loads to purchase their share of the system capacity requirement. The result is that any supplier that owns more capacity than the difference between total supply and the defined demand is pivotal and has market power.

In other words, the market design for capacity leads, almost unavoidably, to structural market power. Given the basic features of market structure in the PJM Capacity Market, including significant market structure issues, inelastic demand, tight supply-demand conditions, the relatively small number of nonaffiliated LSEs and supplier knowledge of aggregate market demand, the MMU concludes that the potential for the exercise of market power continues to be high. Market power is and will remain endemic to the existing structure of the PJM Capacity Market. This is not surprising in that the Capacity Market is the result of a regulatory/administrative decision to require a specified level of reliability and the related decision to require all load serving entities to purchase a share of the capacity required to provide that reliability. It is important to keep these basic facts in mind when designing and evaluating capacity markets. The Capacity Market is unlikely ever to approach the economist's view of a competitive market structure in the absence of a substantial and unlikely structural change that results in much more diversity of ownership.

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 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 in the first three months of calendar year 2011. 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 in the first three months of calendar year 2011.

The MMU has also identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[15,16,17,18,19,20,21]

RPM Capacity Market

Market Structure

Market Concentration

Preliminary Market Structure Screen

15 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>.

16 See "Analysis of the 2010/2011 RPM Third Incremental Auction" (December 20, 2010) <http://www.monitoringanalytics.com/reports/Reports/2010/Analysis_of_2010_2011_RPM_Third_Incremental_Auction_20101220.pdf>.

17 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>.

18 See "Analysis of the 2011/2012 RPM First Incremental Auction" (January 6, 2011) <http://www.monitoringanalytics.com/reports/Reports/2011/Analysis_of_2011_2012_RPM_First_Incremental_Auction_20110106.pdf>.

19 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>.

20 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>.

21 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>.

Table 5-2 Preliminary market structure screen results: 2010/2011 through 2014/2015 RPM Auctions (See 2010 SOM, Table 5-5)

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
2014/2015				
RTO	15.0%	800	1	Fail
MAAC	17.6%	1038	1	Fail
EMAAC	33.1%	1966	1	Fail
SWMAAC	49.4%	4733	1	Fail
PSEG	89.4%	8027	1	Fail
PSEG North	88.2%	7825	1	Fail
DPL South	56.5%	3796	1	Fail
Pepco	94.5%	8955	1	Fail

Auction Market Structure

Table 5-3 RSI results: 2010/2011 through 2013/2014 RPM Auctions[22] (See 2010 SOM, Table 5-6)

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 Incremental Auction			
RTO	0.53	47	47
2011/2012 BRA			
RTO	0.63	76	76
2011/2012 First Incremental Auction			
RTO	0.62	30	30
2011/2012 ATSI FRR Integration Auction			
RTO	0.07	21	21
2011/2012 Third Incremental Auction			
RTO	0.41	52	52
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 ATSI FRR Integration Auction			
RTO	0.10	16	16

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

Table 5-3 RSI results: 2010/2011 through 2013/2014 RPM Auctions (continued)

RPM Markets	RSI_3	Total Participants	Failed RSI_3 Participants
2012/2013 First Incremental Auction			
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

Demand-Side Resources

Table 5-4 RPM load management statistics by LDA: June 1, 2009 to June 1, 2013[23,24] (See 2010 SOM, Table 5-8)

	UCAP (MW)							
	RTO	MAAC+APS	MAAC	EMAAC	SWMAAC	DPL South	PSEG North	Pepco
DR cleared	892.9	813.9			356.3			
DR net replacements	(474.7)	(466.9)			(102.1)			
ILR certified	6,481.5	3,081.0			519.3			
RPM load management @ 01-June-2009	6,899.7	3,428.0			773.5			
DR cleared	962.9					14.9		
DR net replacements	(516.3)					(14.9)		
ILR certified	8,236.4					97.2		
RPM load management @ 01-June-2010	8,683.0					97.2		
DR cleared	1,826.6							
EE cleared	76.4							
DR net replacements	(221.2)							
EE net replacements	0.0							
ILR certified	9,128.3							
RPM load management @ 01-June-2011	10,810.1							
DR cleared	7,524.7		4,897.5	1,807.4		66.1	72.2	
EE cleared	568.9		179.9	20.0		0.0	0.9	
DR net replacements	0.0		0.0	0.0		0.0	0.0	
EE net replacements	0.0		0.0	0.0		0.0	0.0	
RPM load management @ 01-June-2012	8,093.6		5,077.4	1,827.4		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
DR net replacements	0.0		0.0	0.0				0.0
EE net replacements	0.0		0.0	0.0				0.0
RPM load management @ 01-June-2013	9,961.3		6,023.1	2,485.2				583.1

23 For delivery years through 2011/2012, certified ILR data were used in the calculation, because the certified ILR data are now available. The ILR MW for 2011/2012 are certified as of May 6, 2011, but are not final until June 1, 2011 as some of the ILR can be withdrawn by May 31, 2011. Effective the 2012/2013 delivery year, ILR was eliminated. Starting with the 2012/2013 delivery year and also for incremental auctions in the 2011/2012 delivery year, the Energy Efficiency (EE) resource type is eligible to be offered in RPM auctions.

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

Table 5-5 RPM load management cleared capacity and ILR: 2007/2008 through 2013/2014[25,26] (See 2010 SOM, Table 5-9)

	DR Cleared		EE Cleared		ILR	
Delivery Year	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)
2007/2008	123.5	127.6	0.0	0.0	1,584.6	1,636.3
2008/2009	540.9	559.4	0.0	0.0	3,488.5	3,608.1
2009/2010	864.5	892.9	0.0	0.0	6,273.8	6,481.5
2010/2011	930.9	962.9	0.0	0.0	7,961.3	8,236.4
2011/2012	1,766.0	1,826.6	74.0	76.4	8,823.2	9,128.3
2012/2013	7,286.5	7,524.7	551.3	568.9	0.0	0.0
2013/2014	8,977.8	9,281.9	658.5	679.4	0.0	0.0

Table 5-6 RPM load management statistics: June 1, 2007 to June 1, 2013[27,28] (See 2010 SOM, Table 5-10)

	DR and EE Cleared Plus ILR		DR Net Replacements		EE Net Replacements		Total RPM LM	
	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)
01-Jun-07	1,708.1	1,763.9	0.0	0.0	0.0	0.0	1,708.1	1,763.9
01-Jun-08	4,029.4	4,167.5	(38.7)	(40.0)	0.0	0.0	3,990.7	4,127.5
01-Jun-09	7,138.3	7,374.4	(459.5)	(474.7)	0.0	0.0	6,678.8	6,899.7
01-Jun-10	8,892.2	9,199.3	(499.1)	(516.3)	0.0	0.0	8,393.1	8,683.0
01-Jun-11	10,663.2	11,031.3	(213.8)	(221.2)	0.0	0.0	10,449.4	10,810.1
01-Jun-12	7,837.8	8,093.6	0.0	0.0	0.0	0.0	7,837.8	8,093.6
01-Jun-13	9,636.3	9,961.3	0.0	0.0	0.0	0.0	9,636.3	9,961.3

25 For delivery years through 2011/2012, certified ILR data is shown, because the certified ILR data are now available. The ILR MW for 2011/2012 are certified as of May 6, 2011, but are not final until June 1, 2011 as some of the ILR can be withdrawn by May 31, 2011. Effective the 2012/2013 delivery year, ILR was eliminated. Starting with the 2012/2013 delivery year and also for incremental auctions in the 2011/2012 delivery year, the Energy Efficiency (EE) resource type is eligible to be offered in RPM auctions.
26 FRR committed load management resources are not included in this table.
27 For delivery years through 2011/2012, certified ILR data were used in the calculation, because the certified ILR data are now available. The ILR MW for 2011/2012 are certified as of May 6, 2011, but are not final until June 1, 2011 as some of the ILR can be withdrawn by May 31, 2011. Effective the 2012/2013 delivery year, ILR was eliminated. Starting with the 2012/2013 delivery year and also for incremental auctions in the 2011/2012 delivery year, the Energy Efficiency (EE) resource type is eligible to be offered in RPM auctions.
28 FRR committed load management resources are not included in this table.

Market Conduct

Offer Caps

Table 5-7 ACR statistics: 2010/2011 through 2011/2012 RPM Auctions (See 2010 SOM, Table 5-11)

	2010/2011 BRA		2010/2011 Third Incremental Auction		2011/2012 BRA		2011/2012 First Incremental Auction		2011/2012 ATSI Integration Auction		2011/2012 Third Incremental Auction	
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	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%	57	40.4%	21	5.3%
ACR data input (APIR)	134	12.1%	1	0.3%	133	11.8%	18	14.0%	4	2.8%	0	0.0%
ACR data input (non-APIR)	20	1.8%	0	0.0%	12	1.1%	1	0.8%	0	0.0%	0	0.0%
Opportunity cost input	8	0.7%	1	0.3%	24	2.1%	2	1.6%	3	2.1%	2	0.5%
Default ACR and opportunity cost input	0	0.0%	0	0.0%	2	0.2%	3	2.3%	0	0.0%	0	0.0%
Generation resources with calculated offer caps	532	48.1%	9	2.9%	470	41.8%	68	52.8%	64	45.3%	23	5.8%
Uncapped planned generators	15	1.4%	0	0.0%	20	1.8%	1	0.8%	5	3.5%	27	6.8%
Generation resources with uncapped planned uprates	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	1	0.3%
Offer cap of 1.1 times BRA clearing price elected	NA	NA	193	63.7%	NA	NA	NA	NA	52	36.9%	214	53.7%
Generation price takers	557	50.5%	101	33.4%	635	56.4%	60	46.4%	20	14.3%	133	33.4%
Generation resources offered	1,104	100.0%	303	100.0%	1,125	100.0%	129	100.0%	141	100.0%	398	100.0%
Demand resources offered	23		34		37		0		46		74	
Energy efficiency resources offered	0		0		0		0		1		33	
Total capacity resources offered	1,127		337		1,162		129		188		505	

Table 5-8 ACR statistics: 2012/2013 through 2013/2014 RPM Auctions (See 2010 SOM, Table 5-12)

	2012/2013 BRA		2012/2013 ATSI Integration Auction		2012/2013 First Incremental Auction		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	Number of Resources	Percent of Generation Resources Offered
Default ACR selected	465	41.0%	117	67.6%	92	56.8%	580	49.6%
ACR data input (APIR)	118	10.4%	12	6.9%	14	8.6%	92	7.9%
ACR data input (non-APIR)	2	0.2%	0	0.0%	0	0.0%	15	1.3%
Opportunity cost input	8	0.7%	2	1.2%	2	1.2%	6	0.5%
Default ACR and opportunity cost input	14	1.2%	0	0.0%	0	0.0%	7	0.6%
Generation resources with calculated offer caps	607	53.5%	131	75.7%	108	66.6%	700	59.9%
Uncapped planned generators	11	1.0%	0	0.0%	17	10.5%	20	1.7%
Offer cap of 1.1 times BRA clearing price elected	NA	NA	26	15.0%	NA	NA	NA	NA
Generation price takers	515	45.5%	16	9.3%	37	22.9%	450	38.4%
Generation resources offered	1,133	100.0%	173	100.0%	162	100.0%	1,170	100.0%
Demand resources offered	233		46		77		426	
Energy efficiency resources offered	53		2		3		128	
Total capacity resources offered	1,419		221		242		1,724	

Market Performance

Table 5-9 Capacity prices: 2007/2008 through 2013/2014 RPM Auctions (See 2010 SOM, Table 5-14)

	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 Incremental Auction	$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 Incremental Auction	$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 Incremental Auction	$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 Incremental Auction	$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
2011/2012 Third Incremental Auction	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00
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 Incremental Auction	$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

Table 5-10 RPM revenue by type: 2007/2008 through 2013/2014[29,30] (See 2010 SOM, Table 5-15)

Type	2007/2008	2008/2009	2009/2010	2010/2011	2011/2012	2012/2013	2013/2014	Total
Demand Resources	$5,537,085	$35,349,116	$65,762,003	$60,235,796	$55,795,785	$262,109,171	$540,278,140	$1,025,067,095
Energy Efficiency Resources	$0	$0	$0	$0	$139,812	$11,155,913	$18,323,569	$29,619,294
Imports	$22,225,980	$60,918,903	$56,517,793	$106,046,871	$185,421,273	$13,115,246	$31,191,272	$475,437,338
Coal existing	$1,022,993,505	$1,845,819,870	$2,420,481,808	$2,662,434,386	$1,595,707,479	$1,015,782,743	$1,720,750,315	$12,283,970,106
Coal new/reactivated	$0	$0	$1,854,781	$3,168,069	$28,330,047	$7,413,749	$12,493,918	$53,260,564
Gas existing	$1,514,060,691	$1,949,645,918	$2,326,304,914	$2,632,336,161	$1,607,317,731	$1,115,914,101	$1,885,036,661	$13,030,616,178
Gas new/reactivated	$3,472,667	$9,751,112	$30,168,831	$58,065,964	$98,448,693	$75,945,518	$165,431,441	$441,284,226
Hydroelectric existing	$209,490,444	$287,850,403	$364,742,517	$442,429,815	$278,529,660	$178,866,339	$308,348,743	$2,070,257,920
Hydroelectric new/reactivated	$0	$0	$0	$0	$0	$0	$0	$0
Nuclear existing	$996,085,233	$1,322,601,837	$1,517,723,628	$1,799,258,125	$1,079,386,338	$761,838,276	$1,341,583,669	$8,818,477,107
Nuclear new/reactivated	$0	$0	$0	$0	$0	$0	$0	$0
Oil existing	$448,034,948	$532,432,515	$663,370,167	$623,141,070	$368,084,004	$385,912,313	$619,307,680	$3,640,282,698
Oil new/reactivated	$0	$4,837,523	$5,676,582	$4,339,539	$967,887	$2,772,987	$5,669,955	$24,264,473
Solid waste existing	$29,956,764	$33,843,188	$41,243,412	$40,731,606	$25,636,836	$26,835,364	$43,611,119	$241,858,290
Solid waste new/reactivated	$0	$0	$523,739	$413,503	$261,690	$469,425	$2,411,690	$4,080,046
Solar existing	$0	$0	$0	$0	$0	$0	$0	$0
Solar new/reactivated	$0	$0	$0	$0	$66,978	$944,720	$947,905	$1,959,603
Wind existing	$430,065	$1,180,153	$2,011,156	$1,819,413	$1,072,929	$779,404	$1,321,010	$8,614,130
Wind new/reactivated	$0	$2,917,048	$6,836,827	$15,232,177	$9,919,881	$3,771,957	$11,859,958	$50,537,847
Total	$4,252,287,381	$6,087,147,586	$7,503,218,157	$8,449,652,496	$5,335,087,023	$3,863,627,224	$6,708,567,045	$42,199,586,913

29 A resource classified as "new/reactivated" is a capacity resource addition since the implementation of RPM and is considered "new/reactivated" for its initial offer and all its subsequent offers in RPM auctions.
30 The results for the ATSI Integrations Auctions are not included in this table.

Figure 5-1 History of capacity prices: Calendar year 1999 through 2013[31] (See 2010 SOM, Figure 5-1)

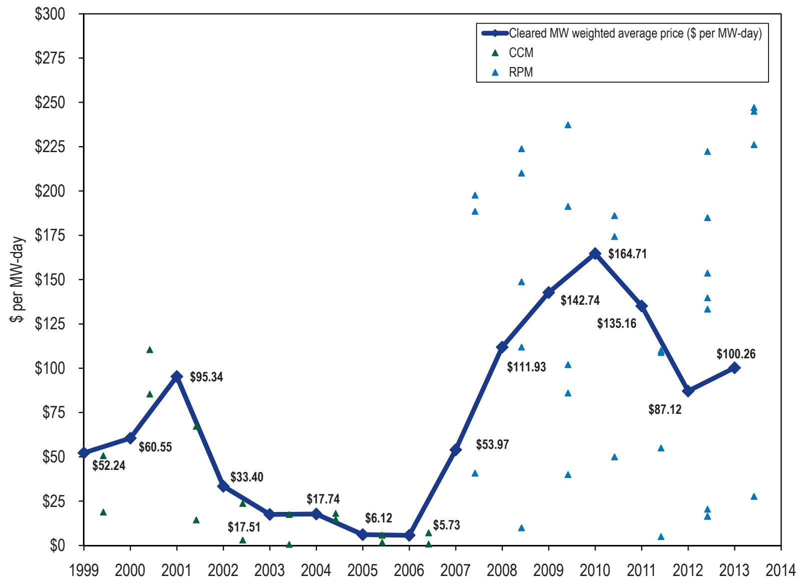


Table 5-11 RPM cost to load: 2010/2011 through 2013/2014[32,33,34] (See 2010 SOM, Table 5-16)

	Net Load Price ($ per MW-day)	UCAP Obligation (MW)	Annual Charges
2010/2011			
RTO	$182.85	129,332.6	$8,631,690,057
DPL	$187.04	4,515.5	$308,271,379
2011/2012			
RTO	$116.23	133,815.3	$5,692,526,949
2012/2013			
RTO	$16.46	69,339.1	$416,582,379
MAAC	$129.75	31,423.4	$1,488,172,945
EMAAC	$139.40	21,027.5	$1,069,900,228
DPL	$168.10	4,521.4	$277,417,279
PSEG	$153.55	12,446.4	$697,567,823
2013/2014			
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

31 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. The CCM data points plotted are cleared MW weighted average prices for the daily and monthly markets by delivery year. The RPM data points plotted are RPM resource clearing prices.

32 The annual charges are calculated using the rounded, net load prices as posted in the PJM Base Residual Auction results.

33 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.

34 Prior to the 2009/2010 delivery year, the Final UCAP Obligation is determined after the clearing of the Second Incremental Auction. For the 2009/2010 through 2011/2012 delivery years, the Final UCAP Obligations are determined after the clearing of the Third Incremental Auction. 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 are not finalized. The 2012/2013 and 2013/2014 Obligation MW are not finalized.

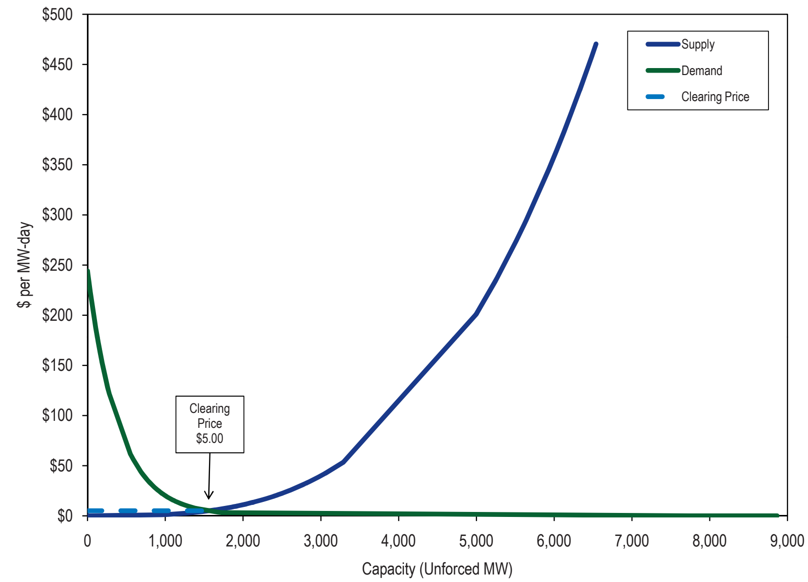
2011/2012 RPM Third Incremental Auction

RTO

Table 5-12 RTO offer statistics: 2011/2012 RPM Third Incremental Auction (See 2010 SOM, Table 5-19)

	Offered (Supply)		Bid (Demand)
	ICAP (MW)	UCAP (MW)	UCAP (MW)
Generation	2,388.2	2,268.1	
DR	4,040.0	4,179.2	
EE	87.8	90.5	
Total	6,516.0	6,537.8	8,865.2
Cleared in RTO	1,575.0	1,557.0	1,557.0
Cleared in LDAs	0.0	0.0	0.0
Total cleared	1,575.0	1,557.0	1,557.0
Uncleared in RTO	4,941.0	4,980.8	7,308.2
Uncleared in LDAs	0.0	0.0	0.0
Total uncleared	4,941.0	4,980.8	7,308.2
Resource clearing price ($ per MW-day)		$5.00	

Figure 5-2 RTO market supply/demand curves: 2011/2012 RPM Third Incremental Auction[35] (New figure)



35 The supply and demand curves have been smoothed using a statistical technique that fits a smooth curve to the underlying data while ensuring that the point of intersection between supply and demand curves is at the market clearing price. The supply curve includes all offered MW, and the demand curve includes all bid MW while the prices reflect the smoothing method.

Generator Performance

Generator Performance Factors

Figure 5-3 PJM equivalent outage and availability factors: Calendar years 2007 to 2011 (January through March) (See 2010 SOM, Figure 5-4)

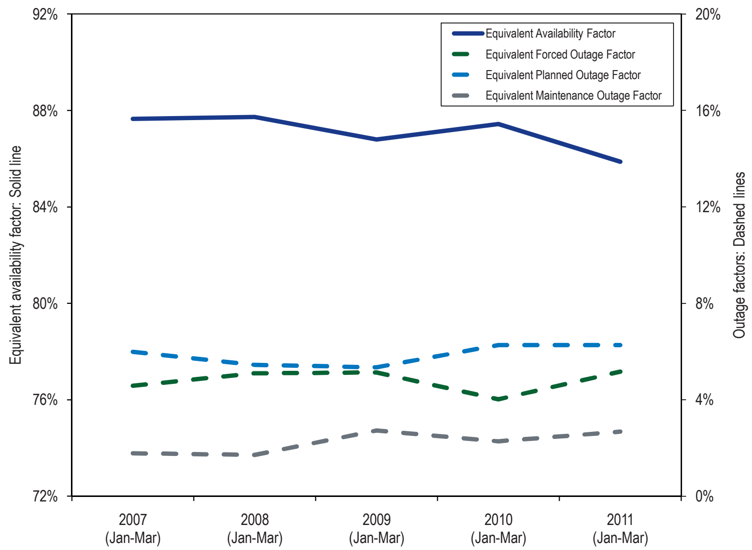
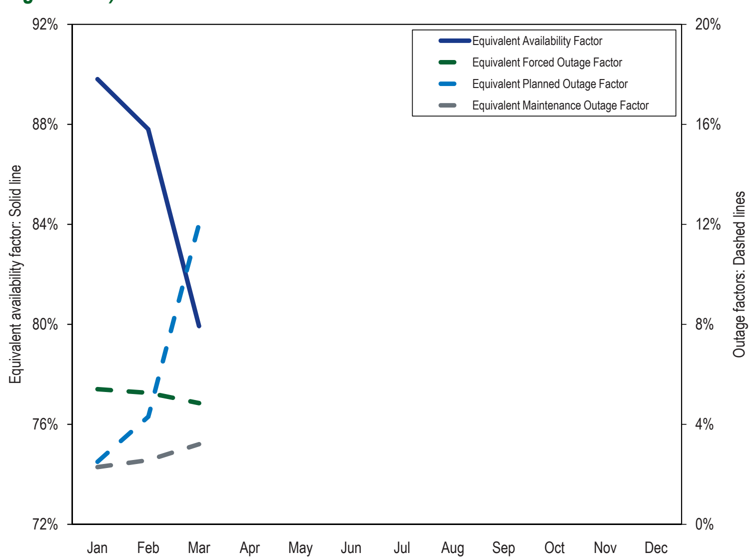
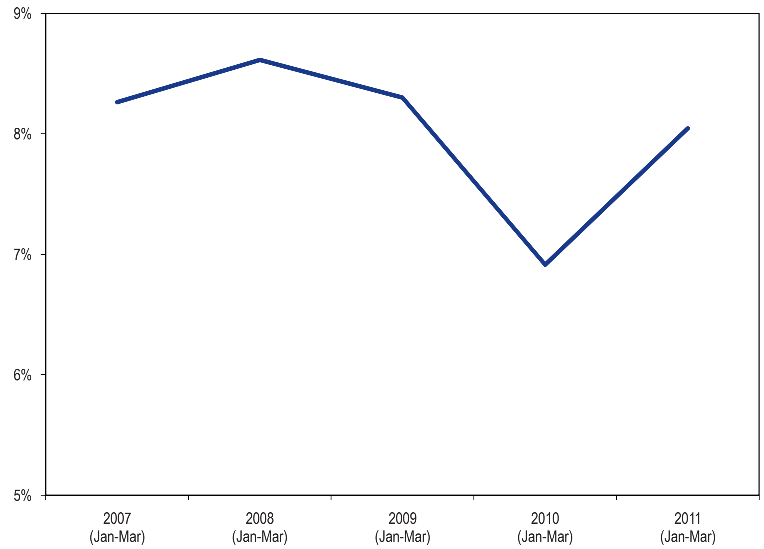


Figure 5-4 Generator performance factors: January through March 2011 (See 2010 SOM, Figure 5-10)



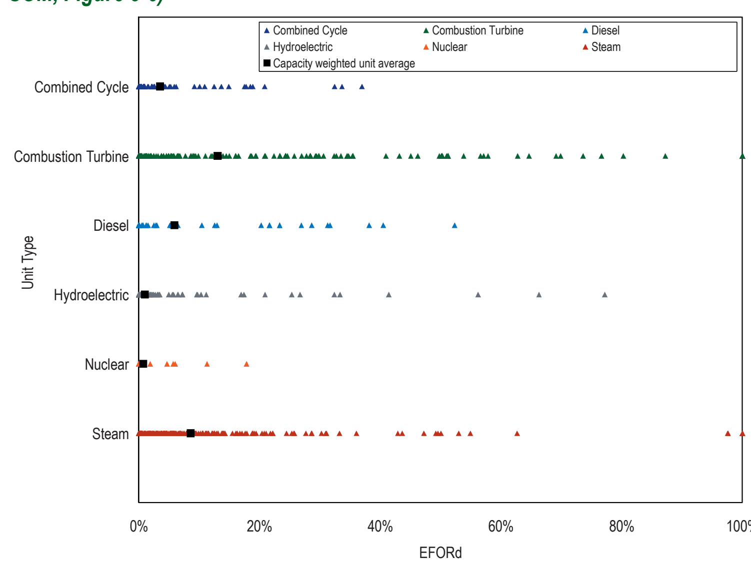
Generator Forced Outage Rates

Figure 5-5 Trends in the PJM equivalent demand forced outage rate (EFORd): Calendar years 2007 to 2011 (January through March) (See 2010 SOM, Figure 5-5)



Distribution of EFORd

Figure 5-6 Distribution of EFORd data by unit type: January through March 2011 (See 2010 SOM, Figure 5-6)



Components of EFORd

Table 5-13 PJM EFORd data: Calendar years 2007 to 2011 (January through March) (See 2010 SOM, Table 5-20)

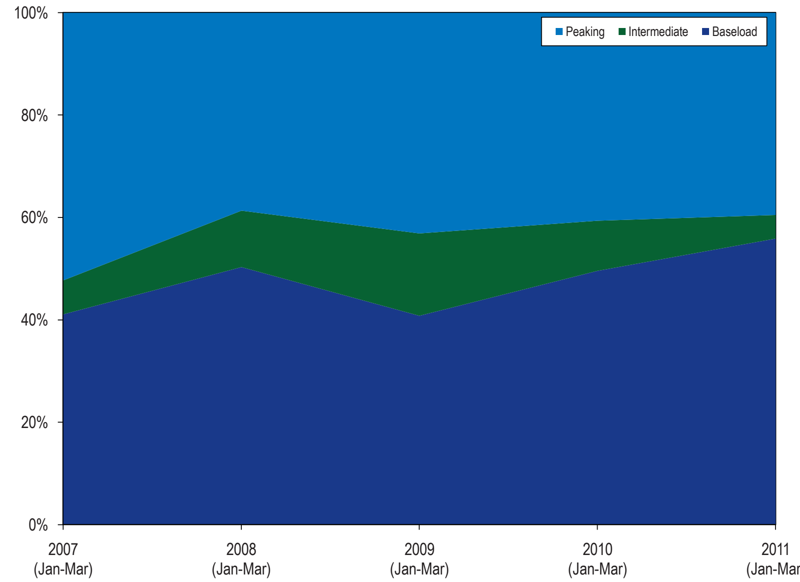
	2007 (Jan-Mar)	2008 (Jan-Mar)	2009 (Jan-Mar)	2010 (Jan-Mar)	2011 (Jan-Mar)
Combined Cycle	8.7%	4.6%	5.3%	3.5%	3.5%
Combustion Turbine	20.2%	16.0%	13.9%	13.1%	8.5%
Diesel	9.1%	10.1%	8.2%	5.9%	6.6%
Hydroelectric	1.9%	2.9%	1.9%	1.0%	2.2%
Nuclear	0.4%	1.5%	3.8%	0.7%	1.6%
Steam	8.0%	10.4%	9.5%	8.6%	12.1%
Total	8.3%	8.6%	8.3%	6.9%	8.0%

Table 5-14 Contribution to EFORd for specific unit types (Percentage points): Calendar years 2007 to 2011[36] (January through March) (See 2010 SOM, Figure 5-21)

	2007 (Jan-Mar)	2008 (Jan-Mar)	2009 (Jan-Mar)	2010 (Jan-Mar)	2011 (Jan-Mar)	Change in 2011 from 2010
Combined Cycle	1.0	0.6	0.6	0.4	0.4	(0.0)
Combustion Turbine	3.2	2.5	2.2	2.1	1.4	(0.7)
Diesel	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric	0.1	0.1	0.1	0.0	0.1	0.0
Nuclear	0.1	0.3	0.7	0.1	0.3	0.2
Steam	3.9	5.2	4.7	4.2	5.9	1.6
Total	8.3	8.6	8.3	6.9	8.0	1.1

Duty Cycle and EFORd

Figure 5-7 Contribution to EFORd by duty cycle: Calendar years 2007 to 2011 (January through March) (See 2010 SOM, Figure 5-7)



36 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.

Forced Outage Analysis

Table 5-15 Contribution to EFOF by unit type by cause: January through March 2011 (See 2010 SOM, Table 5-22)

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	System
Boiler Tube Leaks	7.6%	0.0%	0.0%	0.0%	0.0%	29.0%	24.2%
Economic	1.7%	10.7%	0.0%	3.1%	0.0%	10.7%	9.3%
Boiler Piping System	44.9%	0.0%	0.0%	0.0%	0.0%	5.8%	8.3%
Electrical	5.1%	16.2%	0.0%	5.4%	26.1%	5.9%	7.3%
Boiler Fuel Supply from Bunkers to Boiler	0.2%	0.0%	0.0%	0.0%	0.0%	7.5%	6.1%
Boiler Air and Gas Systems	0.0%	0.0%	0.0%	0.0%	0.0%	4.3%	3.5%
Miscellaneous (Generator)	12.3%	5.1%	2.5%	0.2%	0.0%	2.4%	3.1%
Feedwater System	1.3%	0.0%	0.0%	0.0%	0.0%	3.4%	2.9%
Cooling System	0.0%	0.0%	0.0%	0.0%	10.4%	1.8%	2.0%
Auxiliary Systems	3.3%	19.0%	0.0%	0.6%	0.0%	1.1%	1.9%
Condensate System	0.0%	0.0%	0.0%	0.0%	0.0%	2.3%	1.9%
Boiler Tube Fireside Slagging or Fouling	0.0%	0.0%	0.0%	0.0%	0.0%	2.2%	1.8%
Condensing System	0.1%	0.0%	0.0%	0.0%	1.7%	2.0%	1.7%
Fuel Quality	0.0%	0.0%	1.8%	0.0%	0.0%	2.0%	1.6%
Reactor Coolant System	0.0%	0.0%	0.0%	0.0%	30.4%	0.0%	1.6%
High Pressure Turbine	0.0%	0.0%	0.0%	0.0%	0.0%	2.0%	1.6%
Personnel or Procedure Errors	0.0%	0.0%	0.0%	0.0%	0.0%	1.9%	1.5%
Miscellaneous Boiler Tube Problems	0.0%	0.0%	0.0%	0.0%	0.0%	1.9%	1.5%
Boiler Fuel Supply to Bunker	0.0%	0.0%	0.0%	0.0%	0.0%	1.7%	1.4%
All Other Causes	23.4%	49.0%	95.6%	90.7%	31.4%	12.3%	16.8%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Table 5-16 Contributions to Economic Outages: January through March 2011 (See 2010 SOM, Table 5-23)

	Contribution to Economic Reasons
Lack of fuel (OMC)	95.6%
Lack of fuel (Non-OMC)	2.6%
Other economic problems	1.0%
Lack of water (Hydro)	0.4%
Fuel conservation	0.3%
Total	100.0%

Table 5-17 Contribution to EFOF by unit type: January through March 2011 (See 2010 SOM, Table 5-24)

	EFOF	Contribution to EFOF
Combined Cycle	1.3%	8.0%
Combustion Turbine	2.2%	4.1%
Diesel	3.8%	0.2%
Hydroelectric	0.7%	1.3%
Nuclear	0.7%	5.3%
Steam	6.8%	81.2%
Total	4.0%	100.0%

Outages Deemed Outside Management Control

Table 5-18 OMC Outages: January through March 2011 (See 2010 SOM, Table 5-25)

OMC Cause Code	% of OMC Forced Outages	% of all Forced Outages
Economic	83.0%	8.9%
Electrical	7.2%	0.8%
Catastrophe	6.1%	0.7%
Miscellaneous (External)	3.2%	0.3%
Power Station Switchyard	0.5%	0.1%
Total	100.0%	10.8%

Table 5-19 PJM EFORd vs. XEFORd: January through March 2011 (See 2010 SOM, Table 5-26)

	EFORd	XEFORd	Difference
Combined Cycle	3.5%	3.2%	0.3%
Combustion Turbine	8.5%	6.4%	2.1%
Diesel	6.6%	3.9%	2.7%
Hydroelectric	2.2%	1.8%	0.4%
Nuclear	1.6%	1.6%	0.0%
Steam	12.1%	9.3%	2.8%
Total	8.0%	6.3%	1.7%

Components of EFORp

Table 5-20 Contribution to EFORp by unit type (Percentage points): Calendar years 2010 to 2011 (January through March) (See 2010 SOM, Table 5-27)

	2010 (Jan-Mar)	2011 (Jan-Mar)
Combined Cycle	0.2	0.3
Combustion Turbine	0.4	0.4
Diesel	0.0	0.0
Hydroelectric	0.0	0.1
Nuclear	0.2	0.4
Steam	2.9	3.4
Total	3.7	4.6

Table 5-21 PJM EFORp data by unit type: Calendar years 2010 to 2011 (January through March) (See 2010 SOM, Table 5-28)

	2010 (Jan-Mar)	2011 (Jan-Mar)
Combined Cycle	1.9%	2.4%
Combustion Turbine	2.3%	2.6%
Diesel	3.7%	2.4%
Hydroelectric	0.5%	2.0%
Nuclear	1.0%	2.3%
Steam	5.9%	7.0%
Total	3.7%	4.6%

EFORd, XEFORd and EFORp

Table 5-22 Contribution to PJM EFORd, XEFORd and EFORp by unit type: January through March 2011 (See 2010 SOM, Table 5-29)

	EFORd	XEFORd	EFORp
Combined Cycle	0.4	0.4	0.3
Combustion Turbine	1.4	1.0	0.4
Diesel	0.0	0.0	0.0
Hydroelectric	0.1	0.1	0.1
Nuclear	0.3	0.3	0.4
Steam	5.9	4.5	3.4
Total	8.0	6.3	4.6

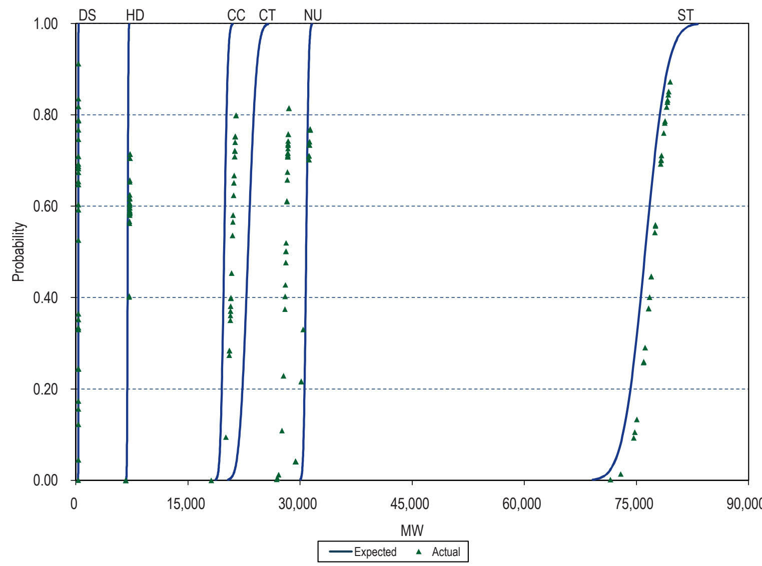
Table 5-23 PJM EFORd, XEFORd and EFORp data by unit type: January through Ma rch 2011[37] (See 2010 SOM, Table 5-30)

	EFORd	XEFORd	EFORp	Difference EFORd and XEFORd	Difference EFORd and EFORp
Combined Cycle	3.5%	3.2%	2.4%	0.3%	1.0%
Combustion Turbine	8.5%	6.4%	2.6%	2.1%	5.9%
Diesel	6.6%	3.9%	2.4%	2.7%	4.2%
Hydroelectric	2.2%	1.8%	2.0%	0.4%	0.2%
Nuclear	1.6%	1.6%	2.3%	0.0%	(0.7%)
Steam	12.1%	9.3%	7.0%	2.8%	5.0%
Total	8.0%	6.3%	4.6%	1.7%	3.4%

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

Comparison of Expected and Actual Performance

Figure 5-8 Distribution of EFORd data by unit type: January through March 2011 (See 2010 SOM, Figure 5-8)



Performance by Month

Figure 5-9 EFORd, XEFORd and EFORp: January through March 2011 (See 2010 SOM, Figure 5-9)