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 six months of calendar year 2011, 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 from 2007 to the present, 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 2014/2015 Base Residual Auction was run in the second quarter of 2011. The RTO annual resource clearing price in the 2014/2015 RPM Base Residual Auction was $125.99 per MW-day, an increase of $98.26 per MW-day from the 2013/2014 RPM Base Residual 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 9,681.0 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 $127.46 per MW-day in 2014.

- Average PJM equivalent demand forced outage rate (EFORd) increased from 7.8 percent in the first six months of 2010 to 7.9 percent in the first six months of 2011.

- The PJM aggregate equivalent availability factor (EAF) decreased from 84.3 percent in the first six months of 2010 to 82.2 percent in the first six months of 2011. The equivalent maintenance outage factor (EMOF) increased from 2.7 percent in the first six months of 2010 to 3.1 percent in the first six months of 2011, the equivalent planned outage factor (EPOF) increased from 8.4 percent from the first six months of 2010 to 9.7 percent in the first six months of 2011, and the equivalent forced outage factor (EFOF) increased from 4.6 percent in the first six months of 2010 to 5.0 percent in the first six months of 2011.

Recommendations

- In this 2011 *Quarterly State of the Market Report for PJM: January through June*, 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 2014/2015 RPM Base Residual Auction totaled 160,486.3 MW, a decrease of 411.8 MW from the 2013/2014 RPM Base Residual Auction.

- **Demand.** The overall RTO reliability requirement, from which the Variable Resource Requirement (VRR) curve is developed, decreased 1,665.6 MW from 149,988.7 MW to 148,323.1 MW. The decrease in the reliability requirement adjusted for FRR, due to an increase in the preliminary FRR obligation offset by the inclusion of the Duke Zone in the preliminary forecast peak load, shifted the RTO market VRR curve to the left.

1 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in the *2011 Quarterly State of the Market Report for PJM: January through June*, 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.

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- **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 2014/2015 Base Residual Auction all participants in the RTO as well as PS North market failed the three pivotal supplier (TPS) market structure test.[7] All participants included in the incremental supply of MAAC passed the test. The incremental demand consists of the MW needed inside the LDA to relieve the constraint. Incremental demand in MAAC was 411.4 MW. The incremental supply in MAAC, considered in the application of the three pivotal supplier test, was 2,415.6 MW.[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.** The 2014/2015 RPM Base Residual Auction was the first auction conducted under the new RPM rules that established two additional demand resource products, Annual DR and Extended Summer DR, along with the implementation of the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement, which define the minimum amount of capacity sought to be procured for each product type.[12] 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.[13] Of the 149,974.7 MW of cleared capacity in the 2014/2015 RPM Base Residual Auction, 14,118.4 MW were DR offers and 822.1 MW were EE offers.

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 24 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 Effective November 1, 2009, DR and EE resources are not included in the TPS test. See 129 FERC ¶ 61,081 (2009) at P 31.
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 134 FERC ¶ 61,066 (2011).
13 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).

Market Performance

2014/2015 RPM Base Residual Auction

- **RTO.** There were 160,486.3 MW offered into the 2014/2015 RPM Base Residual Auction. Cleared volumes in the RTO were 149,974.7 MW. The RTO clearing price for Limited Resources was $125.47 per MW-day. The Extended Summer Resource Requirement was a binding constraint, resulting in an RTO clearing price for Extended Summer Resources and Annual Resources of $125.99 per MW-day.

  Cleared capacity resources across the entire RTO will receive a total of $7.3 billion based on the unforced MW cleared and the prices in the 2014/2015 RPM Base Residual Auction.

Generator Performance

- **Forced Outage Rates.** Average PJM EFORd increased from 7.8 percent in the first six months of 2010 to 7.9 percent in the first six months of 2011.[14]

- **Generator Performance Factors.** The PJM aggregate equivalent availability factor decreased from 84.3 percent in the first six months of 2010 to 82.2 percent in the first six months of 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 procedures of the owning company. In the first six months of 2011, 9.8 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.

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 six months ending June 30, as downloaded from the PJM GADS database on July 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.

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 six 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 six 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]

15 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>.

16 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>.

17 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>.

18 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>.

19 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>.

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RPM Capacity Market

Market Structure

Supply

Table 5-2 RPM generation capacity additions: 2007/2008 through 2014/2015 (See 2010 SOM, Table 5-3)

	ICAP (MW)				
Delivery Year	New Generation Capacity Resources	Reactivated Generation Capacity Resources	Uprates to Existing Generation Capacity Resources	Net Increase in Capacity Imports	Total
2007/2008	19.0	47.0	536.0	1,576.6	2,178.6
2008/2009	145.1	131.0	438.1	107.7	821.9
2009/2010	476.3	0.0	793.3	105.0	1,374.6
2010/2011	1,031.5	170.7	876.3	24.1	2,102.6
2011/2012	2,332.5	501.0	896.8	672.6	4,402.9
2012/2013	901.5	0.0	946.6	676.8	2,524.9
2013/2014	1,080.2	0.0	418.2	963.3	2,461.7
2014/2015	1,102.8	9.0	499.5	1,096.7	2,708.0
Total	7,088.9	858.7	5,404.8	5,222.8	18,575.2

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Market Concentration

Preliminary Market Structure Screen

Table 5-3 Preliminary market structure screen results: 2011/2012 through 2014/2015 RPM Auctions (See 2010 SOM, Table 5-5)

RPM Markets	Highest Market Share	HHI	Pivotal Suppliers	Pass/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 5-4 RSI results: 2011/2012 through 2014/2015 RPM Auctions[20] (See 2010 SOM, Table 5-6)

RPM Markets	RSI_3	Total Participants	Failed RSI_3 Participants
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
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
2014/2015 BRA			
RTO	0.58	93	93
MAAC/SWMAAC/EMAAC/PSEG/DPL South/Pepco	1.03	7	0
PSEG North	0.00	1	1

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

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Demand-Side Resources

Table 5-5 RPM load management statistics by LDA: June 1, 2010 to June 1, 2014[21,22] (See 2010 SOM, Table 5-8)

	UCAP (MW)					
	RTO	MAAC	EMAAC	DPL South	PSEG North	Pepco
DR cleared	962.9			14.9		
DR net replacements	(516.3)			(14.9)		
ILR	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	(1,260.2)					
EE net replacements	0.2					
ILR certified	9,038.0					
RPM load management @ 01-June-2011	9,681.0					
DR cleared	7,744.6	4,939.9	1,836.5	97.2	121.9	
EE cleared	585.6	187.5	27.6	0.0	1.2	
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	8,330.2	5,127.4	1,864.1	97.2	123.1	
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
DR cleared	14,118.4	7,236.8	1,185.1		443.3	
EE cleared	822.1	199.6	9.8		0.0	
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-2014	14,940.5	7,436.4	1,194.9		443.3	

21 For delivery years through 2011/2012, certified ILR data were used in the calculation, because the certified ILR data are now available. 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.

22 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 5-6 RPM load management cleared capacity and ILR: 2007/2008 through 2014/2015[23,24] (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	8,735.9	9,038.0
2012/2013	7,499.3	7,744.6	567.5	585.6	0.0	0.0
2013/2014	8,977.8	9,281.9	658.5	679.4	0.0	0.0
2014/2015	13,663.8	14,118.4	796.9	822.1	0.0	0.0

Table 5-7 RPM load management statistics: June 1, 2007 to June 1, 2014[25,26] (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	10,575.9	10,941.0	(1,218.1)	(1,260.2)	0.2	0.2	9,358.0	9,681.0
01-Jun-12	8,066.8	8,330.2	0.0	0.0	0.0	0.0	8,066.8	8,330.2
01-Jun-13	9,636.3	9,961.3	0.0	0.0	0.0	0.0	9,636.3	9,961.3
01-Jun-14	14,460.7	14,940.5	0.0	0.0	0.0	0.0	14,460.7	14,940.5

23 For delivery years through 2011/2012, certified ILR data is shown, because the certified ILR data are now available. 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 FRR committed load management resources are not included in this table.
25 For delivery years through 2011/2012, certified ILR data were used in the calculation, because the certified ILR data are now available. 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.

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Market Performance

Table 5-8 Capacity prices: 2007/2008 through 2014/2015 RPM Auctions (See 2010 SOM, Table 5-14)

		RPM Clearing Price ($ per MW-day)							
	Product Type	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
2012/2013 Second Incremental Auction		$13.01	$13.01	$13.01	$48.91	$13.01	$48.91	$48.91	$13.01
2013/2014 BRA		$27.73	$226.15	$27.73	$245.00	$226.15	$245.00	$245.00	$247.14
2014/2015 BRA	Limited	$125.47	$125.47	$125.47	$125.47	$125.47	$125.47	$213.97	$125.47
2014/2015 BRA	Extended Summer	$125.99	$136.50	$125.99	$136.50	$136.50	$136.50	$225.00	$136.50
2014/2015 BRA	Annual	$125.99	$136.50	$125.99	$136.50	$136.50	$136.50	$225.00	$136.50

Table 5-9 RPM revenue by type: 2007/2008 through 2014/2015[27,28] (See 2010 SOM, Table 5-15)

Type	2007/2008	2008/2009	2009/2010	2010/2011	2011/2012	2012/2013	2013/2014	2014/2015	Total
Demand Resources	$5,537,085	$35,349,116	$65,762,003	$60,235,796	$55,795,785	$263,534,711	$540,278,140	$666,313,051	$1,692,805,686
Energy Efficiency Resources	$0	$0	$0	$0	$139,812	$11,334,802	$18,323,569	$38,571,074	$68,369,257
Imports	$22,225,980	$60,918,903	$56,517,793	$106,046,871	$185,421,273	$13,115,246	$31,191,272	$178,063,746	$653,501,083
Coal existing	$1,022,993,505	$1,845,819,870	$2,420,481,808	$2,662,434,386	$1,595,707,479	$1,015,994,058	$1,720,750,315	$1,827,519,210	$14,111,700,631
Coal new/reactivated	$0	$0	$1,854,781	$3,168,069	$28,330,047	$7,413,749	$12,493,918	$56,917,305	$110,177,869
Gas existing	$1,513,684,486	$1,949,325,477	$2,325,941,789	$2,631,948,105	$1,607,096,301	$1,116,743,821	$1,885,036,661	$2,003,810,846	$15,033,587,486
Gas new/reactivated	$3,848,872	$10,071,553	$30,531,957	$58,454,021	$98,670,123	$76,551,231	$165,431,441	$184,029,455	$627,588,652
Hydroelectric existing	$209,490,444	$287,850,403	$364,742,517	$442,429,815	$278,529,660	$179,085,726	$308,348,743	$328,877,767	$2,399,355,074
Hydroelectric new/reactivated	$0	$0	$0	$0	$0	$11,397	$0	$6,591,114	$6,602,511
Nuclear existing	$996,085,233	$1,322,601,837	$1,517,723,628	$1,799,258,125	$1,079,386,338	$762,719,367	$1,341,583,669	$1,459,911,217	$10,279,269,415
Nuclear new/reactivated	$0	$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	$385,951,817	$619,307,680	$433,317,895	$4,073,640,096
Oil new/reactivated	$0	$4,837,523	$5,676,582	$4,339,539	$967,887	$2,772,987	$5,669,955	$3,896,120	$28,160,593
Solid waste existing	$29,956,764	$33,843,188	$41,243,412	$40,731,606	$25,636,836	$26,837,739	$43,611,119	$34,529,047	$276,389,711
Solid waste new/reactivated	$0	$0	$523,739	$413,503	$261,690	$469,425	$2,411,690	$1,190,758	$5,270,804
Solar existing	$0	$0	$0	$0	$0	$0	$0	$0	$0
Solar new/reactivated	$0	$0	$0	$0	$66,978	$1,235,710	$947,905	$2,371,155	$4,621,747
Wind existing	$430,065	$1,180,153	$2,011,156	$1,819,413	$1,072,929	$812,644	$1,321,010	$1,491,563	$10,138,933
Wind new/reactivated	$0	$2,917,048	$6,836,827	$15,232,177	$9,919,881	$4,998,533	$11,859,958	$30,987,962	$82,752,385
Total	$4,252,287,381	$6,087,147,586	$7,503,218,157	$8,449,652,496	$5,335,087,023	$3,869,582,961	$6,708,567,045	$7,258,389,284	$49,463,931,934

27 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.
28 The results for the ATSI Integrations Auctions are not included in this table.

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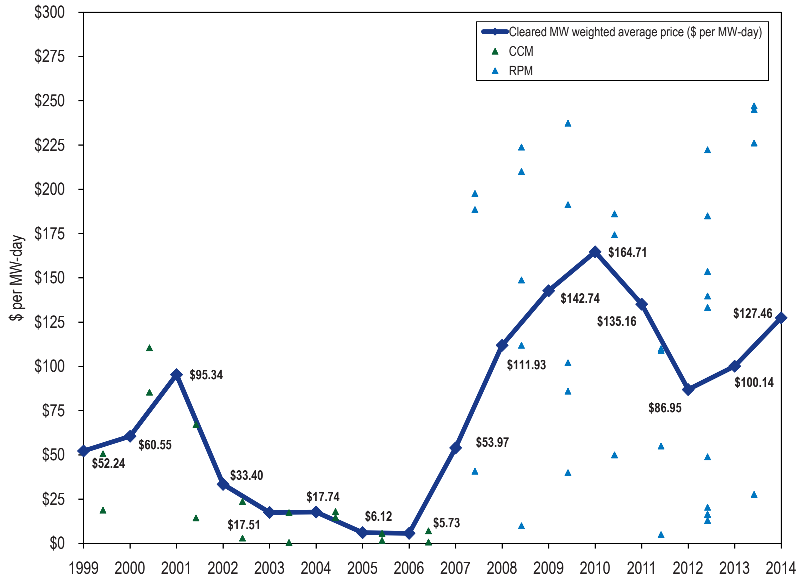
Figure 5-1 History of capacity prices: Calendar year 1999 through 2014[29] (See 2010 SOM, Figure 5-1)



29 1999-2006 capacity prices are CCM combined market, weighted average prices. The 2007 capacity price is a combined CCM/RPM weighted average price. The 2008-2014 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.

Table 5-10 RPM cost to load: 2011/2012 through 2014/2015[30,31,32] (See 2010 SOM, Table 5-16)

	Net Load Price ($ per MW-day)	UCAP Obligation (MW)	Annual Charges
2011/2012			
RTO	$116.16	133,815.3	$5,689,098,601
2012/2013			
RTO	$16.52	67,621.8	$407,745,930
MAAC	$131.48	30,942.6	$1,484,941,563
EMAAC	$141.00	20,476.2	$1,053,813,160
DPL	$169.18	4,584.1	$283,077,133
PSEG	$155.47	12,087.7	$685,916,676
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
2014/2015			
RTO	$125.94	84,581.3	$3,888,042,879
MAAC	$135.25	52,277.4	$2,580,741,594
DPL	$142.99	4,615.4	$240,881,412
PSEG	$164.00	12,208.7	$730,811,202

30 The annual charges are calculated using the rounded, net load prices as posted in the PJM Base Residual Auction results.
31 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.
32 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 2012/2013, 2013/2014, and 2014/2015 Net Load Prices are not finalized. The 2012/2013, 2013/2014, and 2014/2015 Obligation MW are not finalized.

2014/2015 RPM Base Residual Auction

RTO

Table 5-11 RTO offer statistics: 2014/2015 RPM Base Residual Auction[33] (See 2010 SOM, Table 5-19)

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	183,007.5	173,033.4		
DR capacity	20,608.1	21,295.9		
EE capacity	806.5	831.8		
Total internal RTO capacity	204,422.1	195,161.1		
FRR	(33,612.7)	(32,060.2)		
Imports	7,620.2	7,060.4		
RPM capacity	178,429.6	170,161.3		
Exports	(1,230.1)	(1,216.3)		
FRR optional	(2,545.7)	(2,534.2)		
Excused generation	(692.5)	(692.3)		
Excused DR and EE	(5,063.6)	(5,232.2)		
Available	168,897.7	160,486.3	100.0%	100.0%
Generation offered	153,048.1	144,108.8	90.6%	89.8%
DR offered	15,043.1	15,545.6	8.9%	9.7%
EE offered	806.5	831.9	0.5%	0.5%
Total offered	168,897.7	160,486.3	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO	156,796.5	149,689.8	92.8%	93.3%
Cleared in LDAs	320.5	284.9	0.2%	0.2%
Total cleared	157,117.0	149,974.7	93.0%	93.5%
Make-whole		112.6	0.0%	0.1%

Table 5-11 continued on next page.

33 Unoffered DR and EE MW include PJM approved DR and EE modifications that were not offered into the auction.

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Table 5-11 RTO offer statistics: 2014/2015 RPM Base Residual Auction[33] (See 2010 SOM, Table 5-19) (continued)

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Reliability requirement		148,323.1		
Total cleared plus make-whole		150,087.3		
Short-Term Resource Procurement Target		3,708.1		
Net excess/(deficit)		5,472.3		
Resource clearing price for Limited Resources ($ per MW-day)		$125.47		
Resource clearing price for Extended Summer Resources ($ per MW-day)		$125.99		
Resource clearing price for Annual Resources ($ per MW-day)		$125.99		
Preliminary zonal capacity price ($ per MW-day)		$125.94	A	
Base zonal CTR credit rate ($ per MW-day)		$0.00	B	
Preliminary net load price ($ per MW-day)		$125.94	A-B	

Generator Performance

Generator Performance Factors

Figure 5-2 PJM equivalent outage and availability factors: January through June 2007 to 2011 (See 2010 SOM, Figure 5-4)

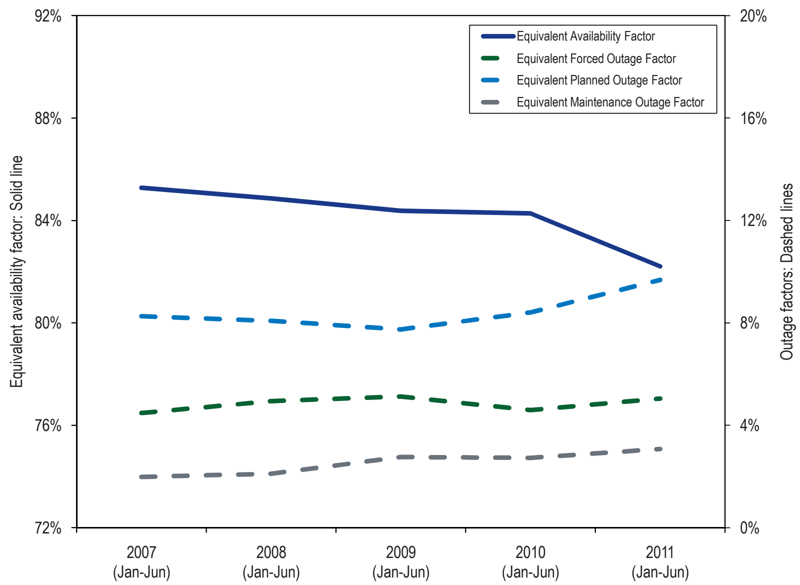
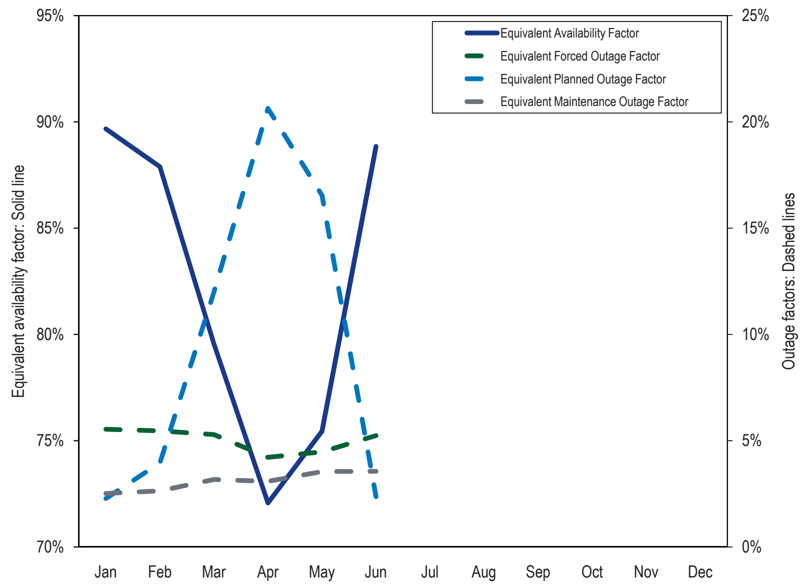


Figure 5-3 Generator performance factors: January through June 2011 (See 2010 SOM, Figure 5-10)



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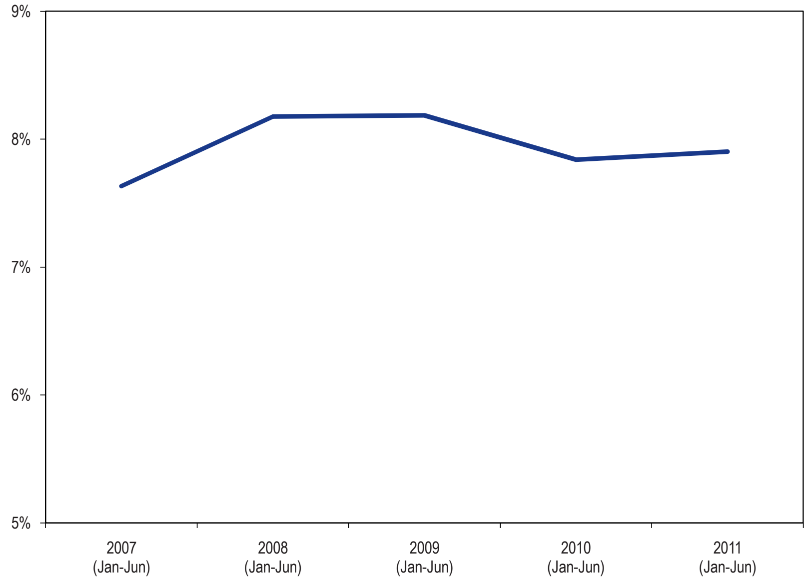
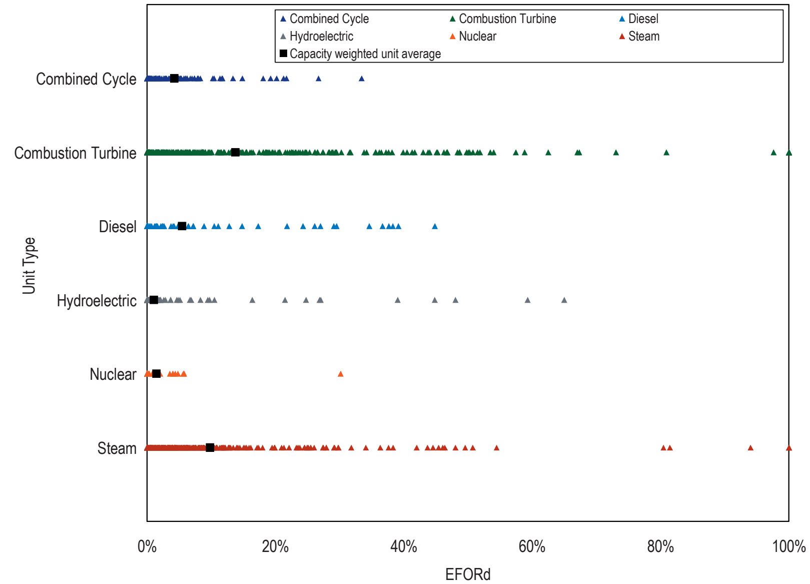
Generator Forced Outage Rates

Figure 5-4 Trends in the PJM equivalent demand forced outage rate (EFORd): January through June 2007 to 2011 (See 2010 SOM, Figure 5-5)



Distribution of EFORd

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



Components of EFORd

Table 5-12 PJM EFORd data: January through June 2007 to 2011 (See 2010 SOM, Table 5-20)

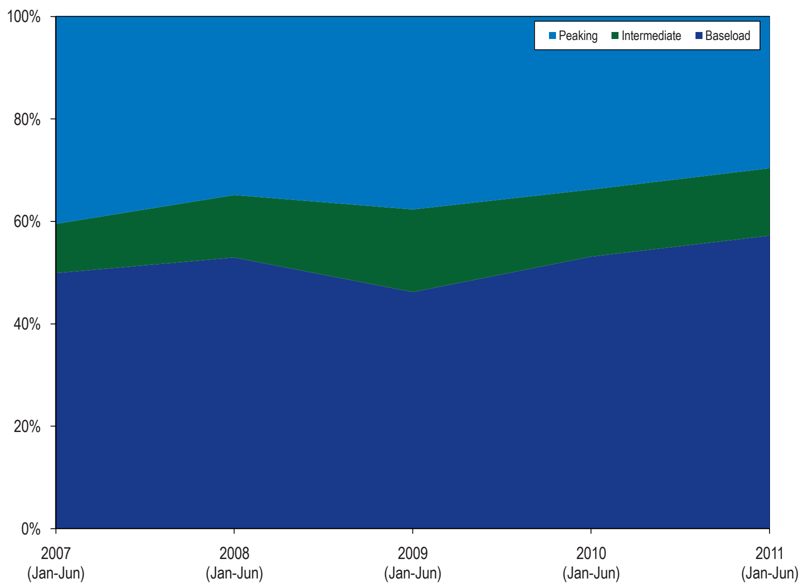
	2007 (Jan-Jun)	2008 (Jan-Jun)	2009 (Jan-Jun)	2010 (Jan-Jun)	2011 (Jan-Jun)
Combined Cycle	3.8%	3.3%	5.1%	4.2%	3.4%
Combustion Turbine	16.8%	14.1%	10.4%	13.8%	8.1%
Diesel	10.7%	10.1%	8.5%	5.5%	7.1%
Hydroelectric	2.2%	2.1%	2.3%	1.1%	2.3%
Nuclear	1.2%	1.1%	4.0%	1.5%	2.0%
Steam	8.7%	10.6%	10.3%	9.8%	11.5%
Total	7.6%	8.2%	8.2%	7.8%	7.9%

Table 5-13 Contribution to EFORd for specific unit types (Percentage points): January through June 2007 to 2011[34] (See 2010 SOM, Figure 5-21)

	2007 (Jan-Jun)	2008 (Jan-Jun)	2009 (Jan-Jun)	2010 (Jan-Jun)	2011 (Jan-Jun)	Change in 2011 from 2010
Combined Cycle	0.4	0.4	0.6	0.5	0.4	(0.1)
Combustion Turbine	2.6	2.2	1.6	2.2	1.3	(0.9)
Diesel	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric	0.1	0.1	0.1	0.0	0.1	0.1
Nuclear	0.2	0.2	0.7	0.3	0.4	0.1
Steam	4.2	5.3	5.1	4.8	5.7	0.9
Total	7.6	8.2	8.2	7.8	7.9	0.1

Duty Cycle and EFORd

Figure 5-6 Contribution to EFORd by duty cycle: January through June 2007 to 2011 (See 2010 SOM, Figure 5-7)



34 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.

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Forced Outage Analysis

Table 5-14 Contribution to EFOF by unit type by cause: January through June 2011 (See 2010 SOM, Table 5-22)

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	System
Boiler Tube Leaks	5.9%	0.0%	0.0%	0.0%	0.0%	27.1%	22.9%
Economic	1.1%	9.3%	0.0%	2.0%	0.0%	8.3%	7.4%
Generator	3.5%	1.4%	1.1%	1.6%	0.0%	8.4%	7.3%
Electrical	13.3%	17.0%	1.5%	23.5%	11.3%	4.2%	5.8%
Boiler Fuel Supply from Bunkers to Boiler	0.2%	0.0%	0.0%	0.0%	0.0%	6.2%	5.2%
Boiler Piping System	21.6%	0.0%	0.0%	0.0%	0.0%	3.5%	4.2%
Boiler Air and Gas Systems	0.0%	0.0%	0.0%	0.0%	0.0%	4.8%	4.0%
Feedwater System	2.5%	0.0%	0.0%	0.0%	0.0%	4.0%	3.5%
Miscellaneous (Generator)	15.3%	3.9%	1.5%	0.1%	5.2%	1.8%	2.8%
Circulating Water Systems	1.6%	0.0%	0.0%	0.0%	12.3%	2.0%	2.5%
Fuel Quality	0.0%	0.0%	1.4%	0.0%	0.0%	2.5%	2.1%
Reactor Coolant System	0.0%	0.0%	0.0%	0.0%	33.4%	0.0%	2.0%
Auxiliary Systems	4.4%	24.3%	0.0%	0.3%	0.0%	1.0%	2.0%
Cooling System	0.0%	0.0%	0.4%	0.6%	4.5%	1.9%	1.9%
Controls	1.6%	1.3%	0.5%	0.5%	10.9%	1.0%	1.6%
Boiler Tube Fireside Slagging or Fouling	0.0%	0.0%	0.0%	0.0%	0.0%	1.8%	1.5%
Miscellaneous (Steam Turbine)	1.0%	0.0%	0.0%	0.0%	0.6%	1.7%	1.5%
High Pressure Turbine	0.0%	0.0%	0.0%	0.0%	0.0%	1.7%	1.4%
Stack Emission	0.0%	6.5%	0.0%	0.0%	0.0%	1.4%	1.4%
All Other Causes	27.9%	36.4%	93.5%	71.5%	21.9%	16.8%	19.2%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Table 5-15 Contributions to Economic Outages: January through June 2011 (See 2010 SOM, Table 5-23)

	Contribution to Economic Reasons
Lack of fuel (OMC)	96.8%
Lack of fuel (Non-OMC)	1.9%
Other economic problems	0.8%
Lack of water (Hydro)	0.3%
Fuel conservation	0.2%
Total	100.0%

Table 5-16 Contribution to EFOF by unit type: January through June 2011 (See 2010 SOM, Table 5-24)

	EFOF	Contribution to EFOF
Combined Cycle	2.8%	5.7%
Combustion Turbine	1.9%	3.6%
Diesel	3.8%	0.1%
Hydroelectric	0.6%	1.1%
Nuclear	1.2%	5.9%
Steam	7.5%	83.5%
Total	4.6%	100.0%

Outages Deemed Outside Management Control

Table 5-17 OMC Outages: January through June 2011 (See 2010 SOM, Table 5-25)

OMC Cause Code	% of OMC Forced Outages	% of all Forced Outages
Economic	72.7%	7.2%
Catastrophe	12.8%	1.3%
Electrical	8.5%	0.8%
Power Station Switchyard	2.9%	0.3%
Miscellaneous (External)	2.8%	0.3%
Fuel Quality	0.4%	0.0%
Regulatory	0.0%	0.0%
Total	100.0%	9.8%

Table 5-18 PJM EFORd vs. XEFORd: January through June 2011 (See 2010 SOM, Table 5-26)

	EFORd	XEFORd	Difference
Combined Cycle	3.4%	3.2%	0.1%
Combustion Turbine	8.1%	6.1%	2.1%
Diesel	7.1%	3.7%	3.5%
Hydroelectric	2.3%	2.0%	0.3%
Nuclear	2.0%	1.9%	0.1%
Steam	11.5%	10.2%	1.3%
Total	7.9%	6.9%	1.0%

Components of EFORp

Table 5-19 Contribution to EFORp by unit type (Percentage points): January through June 2010 and 2011 (See 2010 SOM, Table 5-27)

	2010 (Jan-Jun)	2011 (Jan-Jun)
Combined Cycle	0.5	0.2
Combustion Turbine	0.4	0.4
Diesel	0.0	0.0
Hydroelectric	0.0	0.1
Nuclear	0.3	0.5
Steam	3.4	3.3
Total	4.6	4.5

Table 5-20 PJM EFORp data by unit type: January through June 2010 and 2011 (See 2010 SOM, Table 5-28)

	2010 (Jan-Jun)	2011 (Jan-Jun)
Combined Cycle	4.3%	1.8%
Combustion Turbine	2.5%	2.7%
Diesel	3.9%	2.5%
Hydroelectric	0.5%	2.6%
Nuclear	1.5%	2.7%
Steam	6.8%	6.6%
Total	4.6%	4.5%

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EFORd, XEFORd and EFORp

Table 5-21 Contribution to PJM EFORd, XEFORd and EFORp by unit type: January through June 2011 (See 2010 SOM, Table 5-29)

	EFORd	XEFORd	EFORp
Combined Cycle	0.4	0.4	0.2
Combustion Turbine	1.3	1.0	0.4
Diesel	0.0	0.0	0.0
Hydroelectric	0.1	0.1	0.1
Nuclear	0.4	0.3	0.5
Steam	5.7	5.1	3.3
Total	7.9	6.9	4.5

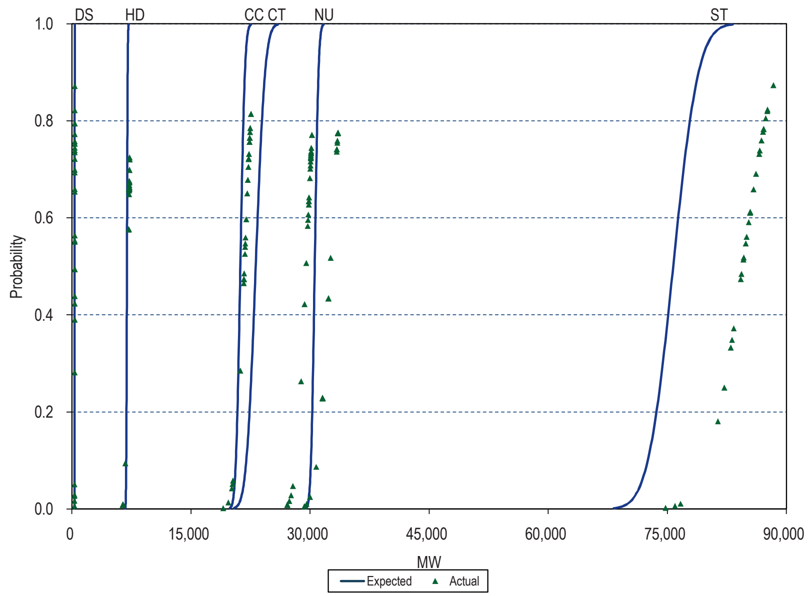
Table 5-22 PJM EFORd, XEFORd and EFORp data by unit type: January through June 2011[35] (See 2010 SOM, Table 5-30)

	EFORd	XEFORd	EFORp	Difference EFORd and XEFORd	Difference EFORd and EFORp
Combined Cycle	3.4%	3.2%	1.8%	0.1%	1.5%
Combustion Turbine	8.1%	6.1%	2.7%	2.1%	5.4%
Diesel	7.1%	3.7%	2.5%	3.5%	4.7%
Hydroelectric	2.3%	2.0%	2.6%	0.3%	(0.3%)
Nuclear	2.0%	1.9%	2.7%	0.1%	(0.7%)
Steam	11.5%	10.2%	6.6%	1.3%	4.9%
Total	7.9%	6.9%	4.5%	1.0%	3.4%

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

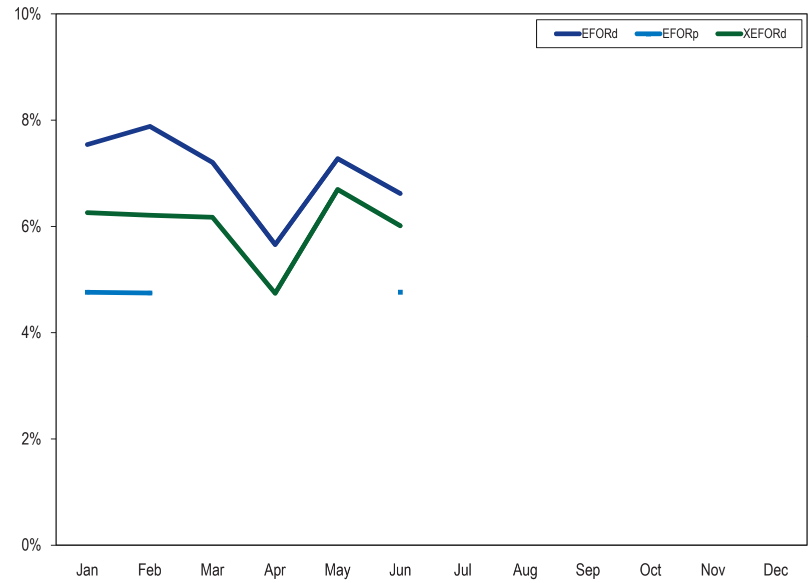
Comparison of Expected and Actual Performance

Figure 5-7 Distribution of EFORd data by unit type: January through June 2011 (See 2010 SOM, Figure 5-8)



Performance by Month

Figure 5-8 EFORd, XEFORd and EFORp: January through June 2011 (See 2010 SOM, Figure 5-9)



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