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 also construct generation and offer it into the capacity market, enter into bilateral contracts, develop demand-side resources and Energy Efficiency (EE) resources and offer them into the capacity market, or construct transmission upgrades and offer 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 nine months of calendar year 2013, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.[1]

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	Competitive	
Market Performance	Competitive	Mixed

- The aggregate market structure was evaluated as not competitive. 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.[2]
- The local market structure was evaluated as not competitive. For almost every auction held, all LDAs have failed the TPS test, which is conducted at the time of the auction.[3]
- 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, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price. Market power mitigation rules were also applied when the Capacity Market Seller submitted a sell offer for a new resource or uprate that was below the Minimum Offer Price Rule (MOPR) threshold.
- 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 and the definition of DR which permits inferior products to substitute for capacity.

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 Existing Generation Capacity Resources and mandatory participation by load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand-side resources.[4]

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.[5] Prior to the 2012/2013 Delivery Year, the Second Incremental Auction was conducted if PJM determined that an unforced capacity resource shortage exceeded 100 MW of unforced capacity due to a load forecast increase. Effective January 31, 2010, First, Second,

1 The values stated in this report for the RTO and LDAs refer to the aggregate level including all nested LDAs unless otherwise specified. For example, RTO values include the entire PJM market and all LDAs. Rest of RTO values are RTO values net of nested LDA values.
2 In the 2008/2009 RPM Third Incremental Auction, 18 participants in the RTO market passed the TPS test.
3 In the 2012/2013 RPM Base Residual Auction, six participants included in the incremental supply of EMAAC passed the TPS test. In the 2014/2015 RPM Base Residual Auction, seven participants in the incremental supply in MAAC passed the TPS test.
4 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in the *2013 Quarterly State of the Market Report for PJM*, Section 5, "Capacity Market" and include all capacity within the PJM footprint.
5 See 126 FERC ¶ 61,275 (2009) at P 86.

and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[6] 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.[7]

RPM prices are locational and may vary depending on transmission constraints.[8] 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, that define the minimum offer price, and that have flexible criteria for competitive offers by new entrants. Demand-side resources and Energy Efficiency resources may be offered directly into RPM Auctions and receive the clearing price without mitigation.

Market Structure

- **PJM Installed Capacity.** During the period January 1 through September 30, 2013, PJM installed capacity increased 3,073.8 MW or 1.7 percent from 182,011.1 MW on January 1 to 185,084.9 MW on September 30. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity on September 30, 2013, 41.9 percent was coal; 28.9 percent was gas; 17.9 percent was nuclear; 6.1 percent was oil; 4.4 percent was hydroelectric; 0.4 percent was solid waste; 0.5 percent was wind, and 0.0 percent was solar.
- **Market Concentration.** In the 2014/2015 RPM Second Incremental Auction and the 2015/2016 RPM First Incremental Auction, all participants in the total PJM market as well as the LDA RPM markets failed the Three Pivotal Supplier (TPS) test. The result was that offer caps were applied to all sell offers for resources which were subject to mitigation when the Capacity Market Seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[9,10,11]
- **Imports and Exports.** Of the 7,493.7 MW of imports offered in the 2016/2017 RPM Base Residual Auction, 7,482.7 MW cleared. Of the cleared imports, 4,723.1 MW (63.1 percent) were from MISO.
- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs was 8,490.0 MW for June 1, 2013 as a result of cleared capacity for Demand Resources and Energy Efficiency Resources in RPM Auctions for the 2013/2014 Delivery Year (11,683.8 MW) less replacement capacity (3,193.8 MW).

Market Conduct

- **2014/2015 RPM Second Incremental Auction.** Of the 221 generation resources which submitted offers, unit-specific offer caps were calculated for six generation resources (2.7 percent). The MMU calculated offer caps for 72 generation resources (32.6 percent), of which 67 were based on the technology specific default (proxy) ACR values.
- **2015/2016 RPM First Incremental Auction.** Of the 131 generation resources which submitted offers, unit-specific offer caps were calculated for 20 generation resources (15.3 percent). The MMU calculated offer caps

6 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).
7 See 126 FERC ¶ 61,275 (2009) at P 88.
8 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.
9 See OATT Attachment DD § 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 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation, and treating a proposed increase in the capability of a Generation Capacity Resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).

for 45 generation resources (34.4 percent), of which 25 were based on the technology specific default (proxy) ACR values.

Market Performance

- The 2014/2015 RPM Second Incremental Auction and the 2015/2016 RPM First Incremental Auction were conducted in the third quarter of 2013. In the 2014/2015 RPM Second Incremental Auction, the RTO clearing price for Annual Resources was $25.00 per MW-day. The weighted average capacity price for the 2014/2015 Delivery Year is $127.74, including all RPM Auctions for the 2014/2015 Delivery Year held through the first nine months of 2013. In the 2015/2016 First Incremental Auction, the RTO clearing price for Annual Resources was $43.00 per MW-day. The weighted average capacity price for the 2015/2016 Delivery Year is $160.03, including all RPM Auctions for the 2015/2016 Delivery Year held through the first nine months of 2013.
- The delivery year weighted average capacity price was $75.08 per MW-day in 2012/2013 and $116.55 per MW-day in 2013/2014.

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd for January through September was 8.0 percent, an increase from the 7.5 percent average PJM EFORd for 2012.[12]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor for January through September was 84.2 percent, a slight increase from the 84.1 percent PJM aggregate equivalent availability factor for 2012.
- **Outages Deemed Outside Management Control (OMC).** In the first nine months of 2013, 34.3 percent of forced outages were classified as OMC outages. OMC outages are excluded from the calculation of the forced outage rate 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 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, but no exercise of market power in the PJM Capacity Market in the first nine months of 2013. 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 nine months of 2013.[13]

The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[14,15,16,17] In 2012, and 2013, the MMU prepared a number of RPM-related reports and testimony, shown in Table 5-2.

12 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 twelve months ending December 31 or the nine months ending September 30, as downloaded from the PJM GADS database on October 22, 2013. 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.

13 For more complete conclusions, see *2012 State of the Market Report for PJM*, Volume II, Section 4, "Capacity Market."

14 See "Analysis of the 2012/2013 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2009/Analysis_of_2012_2013_RPM_Base_Residual_Auction_20090806.pdf> (August 6, 2009).

15 See "Analysis of the 2013/2014 RPM Base Residual Auction Revised and Updated," <http://www.monitoringanalytics.com/reports/Reports/2010/Analysis_of_2013_2014_RPM_Base_Residual_Auction_20090920.pdf> (September 20, 2010).

16 See "Analysis of the 2014/2015 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2012/Analysis_of_2014_2015_RPM_Base_Residual_Auction_20120409.pdf> (April 9, 2012).

17 See "Analysis of the 2015/2016 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2013/Analysis_of_2015_2016_RPM_Base_Residual_Auction_20130924.pdf> (September 24, 2013).

Table 5-2 RPM related MMU reports, 2012 through September, 2013

Date	Name
January 9, 2012	IMM Comments re:MOPR Compliance No. ER11-2875-003 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_ER11-2875-003_20120109.pdf
January 20, 2012	IMM Testimony re: Review of the Potential Impact of the Proposed Capacity Additions in the State of Maryland's Joint Petition for Approval of Settlement MD PSC Case No. 9271 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Testimony_MD_PSC_9271.pdf
January 20, 2012	IMM Comments re: Capacity Procurement RFP MD PSC Case No. 9214 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_MD_PSC_9214.pdf
February 7, 2012	Preliminary Market Structure Screen results for the 2015/2016 RPM Base Residual Auction http://www.monitoringanalytics.com/reports/Reports/2012/PMSS_Results_20152016_20120207.pdf
February 15, 2012	RPM-ACR and RPM Must Offer Obligation FAQs http://www.monitoringanalytics.com/Tools/docs/RPM-ACR_FAQ_RPM_Must_Offer_Obligation_20120215.pdf
February 17, 2012	IMM Motion for Clarification re: Minimum Offer Price Rule Revision Nos.ER11-2871-000, -001 and -002, EL11-20-000 and -001 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Motion_for_Clarification_ER11-2875_EL-20_20120217.pdf
April 9, 2012	Analysis of the 2014/2015 RPM Base Residual Auction www.monitoringanalytics.com/reports/Reports/2012/Analysis_of_2014_2015_RPM_Base_Residual_Auction_20120409.pdf
May 1, 2012	IMM Complaint and Request for Fast Track Treatment and Shortened Comment Period re Complaint v. Unnamed Participant No. EL12-63 www.monitoringanalytics.com/report/Report/2012/IMM_Complaint_and_Fast_Track_Treatment_and_Shortened_Comment_Period_EL12-63-000_20120501.pdf
May 17, 2012	IMM Notice of Withdrawal re Complaint v. Unnamed Participant No. EL12-63 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Notice_of_Withdrawal_EL12-63-000_20120517.pdf
July 3, 2012	Generator Capacity Resources in PJM Region Subject to "Must Offer" Obligation for the 2013/2014, 2014/2015 and 2015/2016 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20120703.pdf
August 10, 2012	IMM Comments re Capacity Portability AD12-16 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_AD12-16_20120810.pdf
August 20, 2012	IMM and PJM Capacity White Papers on OPSI Issues http://www.monitoringanalytics.com/reports/Reports/2012/IMM_And_PJM_Capacity_White_Papers_On_OPSI_Issues_20120820.pdf
August 29, 2012	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2013/2014, 2014/2015 and 2015/2016 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20120829.pdf
November 29, 2012	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2013/2014, 2014/2015 and 2015/2016 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20121129.pdf
December 11, 2012	Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2012 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Report_Replacement_Capacity_Activity_20121211.pdf
March 29, 2013	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2014/2015, 2015/2016 and 2016/2017 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20130329.pdf
April 19, 2013	IMM Answer and Motion for Leave to Answer re: MOPR No. ER13-535-001 http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Answer_and_Motion_for_Leave_to_Answer_ER13-535-001_20130419.pdf
June 19, 2013	Unit Specific MOPR Review Modeling Assumptions http://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Unit_Specific_MOPR_Review_Modeling_Assumptions_20130619.pdf
June 20, 2013	Capacity Deliverability, Docket No. AD12-16 http://www.monitoringanalytics.com/reports/Presentations/2013/IMM_FERC_Capacity_Deliverability_20130620.pdf
June 28, 2013	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2014/2015, 2015/2016 and 2016/2017 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20130628.pdf
July 23, 2013	Analysis of Replacement Capacity for RPM Commitments http://www.monitoringanalytics.com/reports/Presentations/2013/IMM_MIC_Replacement_Capacity_Activity_Rev_20130723.pdf
August 30, 2013	RPM Unit-Specific Offer Cap Review Process http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Unit-Specific_Offer_Cap_Review_Process_20130830.pdf
September 3, 2013	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2014/2015, 2015/2016 and 2016/2017 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20130903.pdf
September 13, 2013	Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2013 http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Report_on_Capacity_Replacement_Activity_2_20130913.pdf
September 13, 2013	IMM Answer and Motion for Leave to Answer re RPM BRA Deadline Changes No. ER13-2140 http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Answer_and_Motion_for_Leave_to_Answer_ER13-2140_20130913.pdf
September 24, 2013	Analysis of the 2015/2016 RPM Base Residual Auction Report http://www.monitoringanalytics.com/reports/Reports/2013/Analysis_of_2015_2016_RPM_Base_Residual_Auction_20130924.pdf

Installed Capacity

On January 1, 2013, PJM installed capacity was 182,011.1 MW (Table 5-3).[18] Over the next nine months, new generation, unit deactivations, facility reratings, plus import and export shifts resulted in PJM installed capacity of 185,084.9 MW on September 30, 2013, an increase of 3,073.8 MW or 1.7 percent over the January 1 level.[19,20] The 3,073.8 MW increase was the result of the integration of the East Kentucky Power Cooperative (EKPC) Zone (2,680.0 MW), new or reactivated generation (276.2 MW), an increase in imports (594.1 MW) capacity modifications (361.3 MW), and a decrease in exports (127.1 MW), offset by deactivations (687.0 MW) and derates (277.9 MW).

At the beginning of the new delivery year on June 1, 2013, PJM installed capacity was 185,567.9 MW, an increase of 3,531.6 MW or 1.9 percent over the May 31 level.

Table 5-3 PJM installed capacity (By fuel source): January 1, May 31, June 1, and September 30, 2013

	1-Jan-13		31-May-13		1-Jun-13		30-Sep-13	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	75,989.2	41.7%	76,055.6	41.8%	77,981.5	42.0%	77,496.7	41.9%
Gas	52,003.2	28.6%	52,106.1	28.6%	53,420.2	28.8%	53,425.9	28.9%
Hydroelectric	7,879.8	4.3%	7,880.4	4.3%	8,091.4	4.4%	8,106.7	4.4%
Nuclear	33,024.0	18.1%	33,024.0	18.1%	33,072.8	17.8%	33,076.9	17.9%
Oil	11,531.2	6.3%	11,361.2	6.2%	11,339.5	6.1%	11,314.2	6.1%
Solar	47.0	0.0%	47.0	0.0%	80.7	0.0%	82.7	0.0%
Solid waste	757.1	0.4%	756.4	0.4%	709.4	0.4%	709.4	0.4%
Wind	779.6	0.4%	805.6	0.4%	872.4	0.5%	872.4	0.5%
Total	182,011.1	100.0%	182,036.3	100.0%	185,567.9	100.0%	185,084.9	100.0%

18 Percent values shown in Table 5-3 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

19 The capacity described in this section is the summer installed capacity rating of all PJM generation capacity resources, as entered into the eRPM system, regardless of whether the capacity cleared in the RPM Auctions.

20 Wind resources accounted for 872.4 MW of installed capacity in PJM on September 30, 2013. This value represents approximately 13 percent of wind nameplate capability in PJM. PJM administratively reduces the capabilities of all wind generators to 13 percent of nameplate capacity when determining the system installed capacity because wind resources cannot be assumed to be available on peak and cannot respond to dispatch requests. As data become available, unforced capability of wind resources will be calculated using actual data. There are additional wind resources not reflected in total capacity because they are energy only resources and do not participate in the PJM Capacity Market.

Table 5-4 Generation capacity changes: 2007/2008 through 2012/2013

	ICAP (MW)									
	Total at June 1	New	Reactivations	Uprates	Integration	Net Change in Capacity Imports	Net Change in Capacity Exports	Deactivations	Derates	Net Change
2007/2008	163,659.4	372.8	156.8	1,238.1	0.0	(96.7)	143.9	389.5	617.8	519.8
2008/2009	164,179.2	812.9	6.3	1,108.9	0.0	871.1	(1,702.9)	615.0	612.4	3,274.7
2009/2010	167,453.9	188.1	13.0	370.4	0.0	68.6	735.9	472.4	171.2	(739.4)
2010/2011	166,714.5	1,751.2	16.0	587.3	11,821.6	187.2	(427.0)	1,439.2	286.9	13,064.2
2011/2012	179,778.7	3,095.0	138.0	553.8	3,607.4	262.7	(1,374.5)	2,758.5	313.0	5,959.9
2012/2013	185,738.6	266.4	79.0	364.5	2,680.0	841.8	(17.3)	4,152.1	267.6	(170.7)
Total		6,486.4	409.1	4,223.0	18,109.0	2,134.7	(2,641.9)	9,826.7	2,268.9	21,908.5

RPM Capacity Market

The RPM Capacity Market, implemented June 1, 2007, is a forward-looking, annual, locational market, with a must-offer requirement for Existing Generation Capacity Resources and mandatory participation by load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand-side resources.

Annual base auctions are held in May for delivery years that are three years in the future. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[21] In the third quarter of 2013, a Second Incremental Auction was held in July for the 2014/2015 Delivery Year, and a First Incremental Auction was held in September for the 2015/2016 Delivery Year.

Market Structure

Supply

Table 5-4 shows generation capacity changes since the implementation of the Reliability Pricing Model through the 2012/2013 Delivery Year. The 21,908.5 MW increase was the result of new Generation Capacity Resources (6,486.4 MW), reactivated Generation Capacity Resources (409.1 MW), uprates (4,223.0 MW), integration of external zones (18,109.0 MW), a net increase in capacity imports (2,134.7 MW), a net decrease in capacity exports (2,641.9 MW), offset by deactivations (9,826.7 MW) and derates (2,268.9 MW).

In the 2014/2015 RPM Second Incremental Auction, 2,909.5 MW cleared of the 6,038.8 MW of participant sell offers. In the 2015/2016 RPM First Incremental Auction, 4,171.5 MW cleared of the 6,773.2 MW of participant sell offers. Effective with the 2012/2013 delivery year, PJM sell offers and buys bids are submitted in RPM Incremental Auctions as a result of changes in the RTO and LDA reliability requirements and the procurement of the Short-Term Resource Procurement Target. In the 2014/2015 RPM Second Incremental Auction, 1,635.3 MW cleared of the 2,039.8 MW of PJM sell offers for the RTO. In the 2015/2016 RPM Second Incremental Auction, 1,876.0 MW cleared of the 2,155.1 MW of PJM sell offers for the RTO.

Demand

In the 2014/2015 RPM Second Incremental Auction, 4,476.4 MW cleared of the 11,133.2 MW of participant buy bids, and 68.4 MW cleared of the 143.0 MW of PJM buy bids for the RTO. In the 2015/2016 RPM First Incremental Auction, 5,987.4 MW cleared of the 21,304.7 MW of participant buy bids, and 60.1 MW cleared of the 60.1 MW of PJM buy bids for the RTO. Participant buy bids are submitted to cover commitment and compliance shortfalls or because participants wanted to purchase additional capacity.

21 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).

Market Concentration

Auction Market Structure

As shown in Table 5-5, all participants in the total PJM market as well as the LDA RPM markets failed the Three Pivotal Supplier (TPS) test in the 2014/2015 RPM Second Incremental Auction and the 2015/2016 RPM First Incremental Auction.[22] The result was that offer caps were applied to all sell offers for resources which were subject to mitigation when the Capacity Market Seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[23,24,25]

Table 5-5 presents the results of the TPS test. A generation owner or owners are pivotal if the capacity of the owners' generation facilities is needed to meet the demand for capacity.

Table 5-5 RSI results: 2013/2014 through 2016/2017 RPM Auctions[26]

RPM Markets	$RSI_{1, 1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
2013/2014 BRA				
RTO	0.80	0.59	87	87
MAAC/SWMAAC	0.42	0.23	9	9
EMAAC/PSEG/PSEG North/DPL South	0.25	0.00	2	2
Pepco	0.00	0.00	1	1
2013/2014 First Incremental Auction				
RTO/MAAC	0.24	0.28	33	33
EMAAC/PSEG/PSEG North/DPL South	0.34	0.00	3	3
SWMAAC/Pepco	0.00	0.00	0	0
2013/2014 Second Incremental Auction				
RTO	0.44	0.27	32	32
MAAC/SWMAAC/Pepco	0.00	0.00	0	0
EMAAC/PSEG/PSEG North/DPL South	0.00	0.00	0	0
2013/2014 Third Incremental Auction				
RTO	0.60	0.38	60	60
MAAC/SWMAAC/Pepco	0.01	0.02	4	4
EMAAC/PSEG/PSEG North/DPL South	0.38	0.22	7	7
2014/2015 BRA				
RTO	0.76	0.58	93	93
MAAC/SWMAAC/EMAAC/PSEG/DPL South/Pepco	1.40	1.03	7	0
PSEG North	0.00	0.00	1	1
2014/2015 First Incremental Auction				
RTO	0.45	0.14	36	36
MAAC/SWMAAC/EMAAC/PSEG/DPL South/Pepco	0.00	0.00	1	1
PSEG North	0.00	0.00	1	1
2014/2015 Second Incremental Auction				
RTO	0.71	0.42	40	40
MAAC/SWMAAC/EMAAC/PSEG/DPL South/Pepco	0.40	0.01	4	4
PSEG North	0.00	0.00	1	1
2015/2016 BRA				
RTO	0.75	0.57	99	99
MAAC/EMAAC/SWMAAC/PSEG/PSEG North/DPL South/Pepco	0.49	0.63	12	12
ATSI	0.01	0.00	3	3
2015/2016 First Incremental Auction				
RTO	0.70	0.61	43	43
MAAC/EMAAC/SWMAAC/DPL South/Pepco	0.15	0.09	5	5
PSEG/PSEG North	0.00	0.00	1	1
ATSI	0.00	0.00	1	1
2016/2017 BRA				
RTO	0.78	0.59	110	110
MAAC/EMAAC/SWMAAC/DPL South/Pepco	0.56	0.38	6	6
PSEG/PSEG North	0.00	0.00	1	1
ATSI/ATSI Cleveland	0.00	0.00	1	1

22 The market definition used for the TPS test includes all offers with costs less than or equal to 1.50 times the clearing price. See *MMU Technical Reference for PJM Markets*, at "Three Pivotal Supplier Test" for additional discussion.
23 See OATT Attachment DD § 6.5.
24 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.
25 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation, and treating a proposed increase in the capability of a Generation Capacity Resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).

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

Locational Deliverability Areas (LDAs)

Under the PJM Tariff, PJM determines, in advance of each BRA, whether defined Locational Deliverability Areas (LDAs) will be modeled in the auction. Effective with the 2012/2013 delivery year, an LDA will be modeled as a potentially constrained LDA for a delivery year if the Capacity Emergency Transfer Limit (CETL) is less than 1.15 times the Capacity Emergency Transfer Objective (CETO), such LDA had a locational price adder in one or more of the three immediately preceding BRAs, or such LDA is determined by PJM in a preliminary analysis to be likely to have a locational price adder based on historic offer price levels. The rules also provide that starting with the 2012/2013 delivery year, EMAAC, SWMAAC, and MAAC LDAs will be modeled as potentially constrained LDAs regardless of the results of the above three tests.[27] In addition, PJM may establish a constrained LDA even if it does not qualify under the above tests if PJM finds that "such is required to achieve an acceptable level of reliability."[28] A reliability requirement, a Variable Resource Requirement (VRR) curve, a Minimum Annual Resource Requirement, and a Minimum Extended Summer Resource Requirement are established for each modeled LDA.

Locational Deliverability Areas are shown in Figure 5-1, Figure 5-2 and Figure 5-3.

27 Prior to the 2012/2013 delivery year, an LDA with a CETL less than 1.05 times CETO was modeled as a constrained LDA in RPM. No additional criteria were used in determining modeled LDAs.
28 OATT Attachment DD § 5.10 (a) (ii).

Figure 5-1 Map of PJM Locational Deliverability Areas

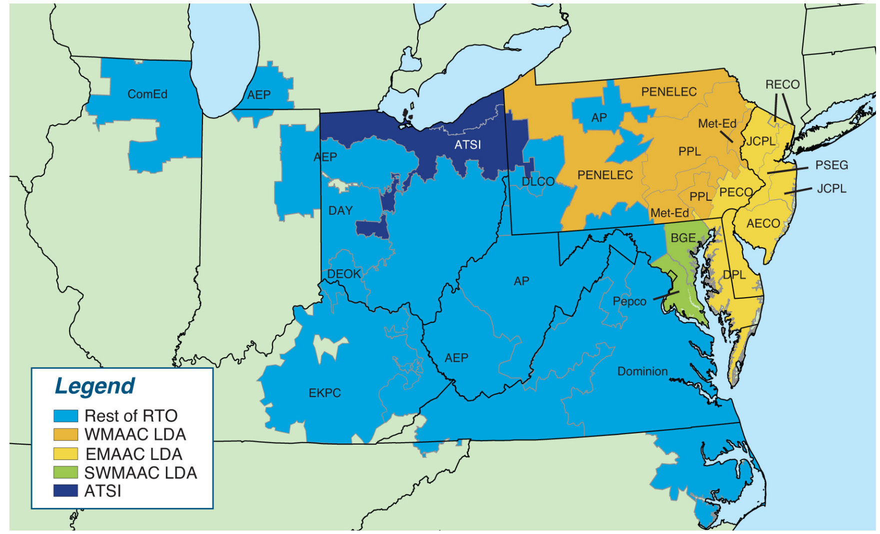


Figure 5-2 Map of PJM RPM EMAAC subzonal LDAs

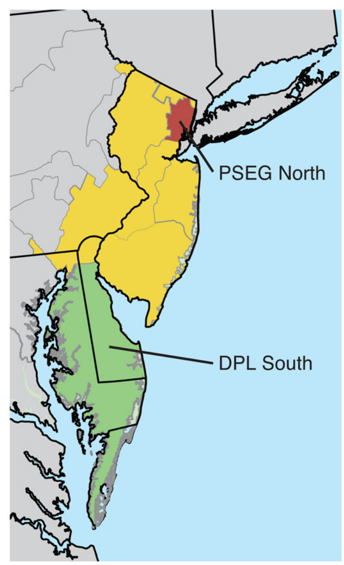
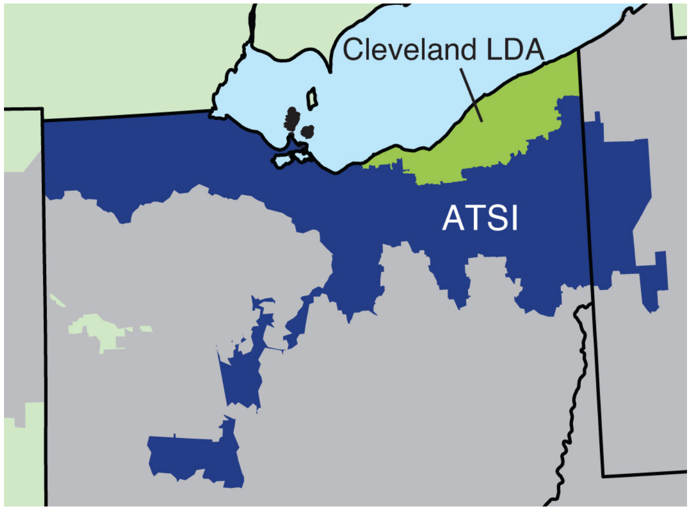


Figure 5-3 Map of PJM RPM ATSI subzonal LDA



Imports and Exports

Units external to the metered boundaries of PJM can qualify as PJM capacity resources if they meet the requirements to be capacity resources. Generators on the PJM system that do not have a commitment to serve PJM loads in the given delivery year as a result of RPM Auctions, FRR capacity plans, locational UCAP transactions, and/or are not designated as a replacement resource, are eligible to export their capacity from PJM.[29] As shown in Table 5-6, a total of 7,482.7 MW of imports cleared in the 2016/2017 RPM Base Residual Auction. Of these cleared imports, 4,723.1 MW (63.1 percent) were from MISO.

Table 5-6 RPM imports: 2007/2008 through 2016/2017 RPM Base Residual Auctions

	UCAP (MW)					
	MISO		Non-MISO		Total Imports	
Base Residual Auction	Offered	Cleared	Offered	Cleared	Offered	Cleared
2007/2008	1,073.0	1,072.9	547.9	547.9	1,620.9	1,620.8
2008/2009	1,149.4	1,109.0	517.6	516.8	1,667.0	1,625.8
2009/2010	1,189.2	1,151.0	518.8	518.1	1,708.0	1,669.1
2010/2011	1,194.2	1,186.6	539.8	539.5	1,734.0	1,726.1
2011/2012	1,862.7	1,198.6	3,560.0	3,557.5	5,422.7	4,756.1
2012/2013	1,415.9	1,298.8	1,036.7	1,036.7	2,452.6	2,335.5
2013/2014	1,895.1	1,895.1	1,358.9	1,358.9	3,254.0	3,254.0
2014/2015	1,067.7	1,067.7	1,948.8	1,948.8	3,016.5	3,016.5
2015/2016	1,538.7	1,538.7	2,396.6	2,396.6	3,935.3	3,935.3
2016/2017	4,723.1	4,723.1	2,770.6	2,759.6	7,493.7	7,482.7

Demand-Side Resources

As shown in Table 5-7 and Table 5-9, capacity in the RPM load management programs was 8,490.0 MW for June 1, 2013 as a result of cleared capacity for Demand Resources and Energy Efficiency Resources in RPM Auctions for the 2013/2014 Delivery Year (11,683.8 MW) less replacement capacity (3,193.8 MW). Table 5-8 shows RPM commitments for DR and EE resources as the result of RPM Auctions prior to adjustments for replacement capacity transactions and certified ILR.

29 OATT Attachment DD § 5.6.6(b).

Table 5-7 RPM load management statistics by LDA: June 1, 2012 to June 1, 2016[30,31,32]

	UCAP (MW)									
	RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ATSI Cleveland
DR cleared	8,740.9	5,193.6	1,971.8	1,794.4	71.0	517.8	97.9			
EE cleared	666.1	253.6	48.1	160.1	0.0	15.9	7.8			
DR net replacements	(2,253.6)	(1,848.6)	(761.5)	(645.5)	(30.6)	(182.9)	10.1			
EE net replacements	(34.9)	(32.4)	(16.2)	(16.5)	0.0	(3.0)	(1.0)			
RPM load management @ 01-Jun-12	7,118.5	3,566.2	1,242.2	1,292.5	40.4	347.8	114.8			
DR cleared	10,779.6	6,466.6	2,735.7	1,788.8	155.4	1,185.0	534.8	661.9		
EE cleared	904.2	289.9	65.2	149.5	10.7	26.2	9.4	72.7		
DR net replacements	(3,318.8)	(3,016.9)	(1,434.3)	(745.7)	(53.3)	(819.7)	(388.6)	(272.4)		
EE net replacements	125.0	121.8	(11.1)	124.2	2.2	(2.1)	1.4	4.8		
RPM load management @ 01-Jun-13	8,490.0	3,861.4	1,355.5	1,316.8	115.0	389.4	157.0	467.0		
DR cleared	14,401.9	7,343.9	2,939.5	2,253.9	220.9	989.7	468.2	912.1		
EE cleared	1,021.9	291.9	37.3	169.8	8.1	17.0	8.2	51.4		
DR net replacements	(5.9)	(5.4)	(2.4)	(0.3)	0.0	(0.6)	0.0	0.0		
EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
RPM load management @ 01-Jun-14	15,417.9	7,630.4	2,974.4	2,423.4	229.0	1,006.1	476.4	963.5		
DR cleared	14,922.1	6,692.2	2,631.3	2,009.1	86.3	797.0	263.3	867.4	1,763.7	
EE cleared	1,009.9	241.8	42.2	159.4	0.0	10.7	3.1	55.8	81.9	
DR net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
RPM load management @ 01-Jun-15	15,932.0	6,934.0	2,673.5	2,168.5	86.3	807.7	266.4	923.2	1,845.6	
DR cleared	12,408.1	5,350.2	2,006.4	1,600.5	105.7	630.7	226.6	663.9	1,811.9	468.7
EE cleared	1,117.3	310.1	51.2	208.4	0.6	11.9	3.1	83.5	196.6	52.6
DR net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RPM load management @ 01-Jun-16	13,525.4	5,660.3	2,057.6	1,808.9	106.3	642.6	229.7	747.4	2,008.5	521.3

30 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.

31 The reported DR cleared MW may reflect reductions in the level of committed MW due to relief from Capacity Resource Deficiency Charges. See OATT Attachment DD § 8.4. For the 2012/2013 Delivery Year, relief from charges was granted by PJM for 11.7 MW.

32 Pursuant to PJM Operating Agreement § 15.1.6(c), PJM Settlement shall attempt to close out and liquidate forward capacity commitments for PJM Members that are declared in collateral default. The replacement transactions reported for the 2014/2015 Delivery Year are associated with RTP Controls, Inc. which was declared in collateral default on March 9, 2012.

Table 5-8 RPM load management cleared capacity and ILR: 2007/2008 through 2016/2017[33,34]

	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	8,730.7	9,032.6
2012/2013	8,429.7	8,740.9	643.4	666.1	0.0	0.0
2013/2014	10,345.6	10,779.6	871.0	904.2	0.0	0.0
2014/2015	13,835.5	14,401.9	983.2	1,021.9	0.0	0.0
2015/2016	14,358.3	14,922.1	973.0	1,009.9	0.0	0.0
2016/2017	11,918.7	12,408.1	1,074.7	1,117.3	0.0	0.0

Table 5-9 RPM load management statistics: June 1, 2007 to June 1, 2016[35,36]

	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	10,570.7	10,935.6	(1,017.3)	(1,052.4)	0.2	0.2	9,553.6	9,883.4
01-Jun-12	9,073.1	9,407.0	(2,173.4)	(2,253.6)	(33.7)	(34.9)	6,866.0	7,118.5
01-Jun-13	11,216.6	11,683.8	(3,184.8)	(3,318.8)	120.0	125.0	8,151.8	8,490.0
01-Jun-14	14,818.7	15,423.8	(5.7)	(5.9)	0.0	0.0	14,813.0	15,417.9
01-Jun-15	15,331.3	15,932.0	0.0	0.0	0.0	0.0	15,331.3	15,932.0
01-Jun-16	12,993.4	13,525.4	0.0	0.0	0.0	0.0	12,993.4	13,525.4

33 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.

34 The reported DR cleared MW may reflect reductions in the level of committed MW due to relief from Capacity Resource Deficiency Charges. See OATT Attachment DD § 8.4. For the 2012/2013 Delivery Year, relief from charges was granted by PJM for 11.7 MW.

35 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.

36 Pursuant to PJM Operating Agreement § 15.1.6(c), PJM Settlement shall attempt to close out and liquidate forward capacity commitments for PJM Members that are declared in collateral default. The replacement transactions reported for the 2014/2015 Delivery Year are associated with RTP Controls, Inc. which was declared in collateral default on March 9, 2012.

Market Conduct

Offer Caps and Offer Floors

Market power mitigation measures were applied to Capacity Resources such that the sell offer was set equal to the defined offer cap when the Capacity Market Seller failed the market structure test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[37,38,39]

37 See OATT Attachment DD § 6.5.

38 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.

39 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation, and treating a proposed increase in the capability of a Generation Capacity Resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).

Table 5-10 ACR statistics: Auctions conducted in third quarter, 2013

	2014/2015 Second Incremental Auction		2015/2016 First Incremental Auction	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	66	29.9%	24	18.3%
ACR data input (APIR)	5	2.3%	16	12.2%
ACR data input (non-APIR)	0	0.0%	0	0.0%
Opportunity cost input	0	0.0%	4	3.1%
Default ACR and opportunity cost	1	0.5%	0	0.0%
Offer cap of 1.1 times BRA clearing price elected	NA	NA	NA	NA
Uncapped planned uprate and default ACR	0	0.0%	1	0.8%
Uncapped planned uprate and opportunity cost	0	0.0%	0	0.0%
Uncapped planned uprate and price taker	0	0.0%	0	0.0%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	NA	NA
Uncapped planned generation resources	5	2.3%	3	2.3%
Price takers	144	65.2%	83	63.4%
Total Generation Capacity Resources offered	221	100.0%	131	100.0%

2014/2015 RPM Second Incremental Auction

As shown in Table 5-10, 221 generation resources submitted offers in the 2014/2015RPM Second Incremental Auction. Unit-specific offer caps were calculated for six generation resources (2.7 percent), including five generation resources (2.3 percent) with an Avoidable Project Investment Recovery Rate (APIR). The MMU calculated offer caps for 72 generation resources (32.6 percent), of which 67 (30.3 percent) were based on the technology specific default (proxy) ACR values. Of the 221 generation resources, five Planned Generation Capacity Resources had uncapped offers (2.3 percent), while the remaining 144 generation resources were price takers (65.2 percent). Market power mitigation was applied to the sell offers for two generation resources.

2015/2016 RPM First Incremental Auction

As shown in Table 5-10, 131 generation resources submitted offers in the 2015/2016 RPM First Incremental Auction. Unit-specific offer caps were calculated for 20 generation resources (15.3 percent), including 16 generation resources with an Avoidable Project Investment Recovery Rate (APIR). The MMU calculated offer caps for 45 generation resources (34.4 percent), of which 25 (19.1 percent) were based on the technology specific default (proxy) ACR values. Of the 221 generation resources, three Planned Generation Capacity Resources had uncapped offers (2.3 percent), one generation resource had an uncapped planned uprate along with a default ACR based offer cap for the existing portion (0.8 percent), while the remaining 83 generation resources were price takers (63.4 percent). Market power mitigation was applied to the sell offer for one generation resource.

Market Performance[40]

Figure 5-4 presents cleared MW weighted average capacity market prices on a delivery year basis for the entire history of the PJM capacity markets. Table 5-11 shows RPM clearing prices for all RPM Auctions held through the first nine months of 2013.

Figure 5-5 illustrates the RPM cleared MW weighted average prices for each LDA for the current delivery year and all results for future delivery years that have been held through the first nine months of 2013.

Table 5-12 shows RPM revenue by resource type for all RPM Auctions held through the first nine months of 2013 with $2.1 billion for new/repower/reactivated generation resources based on the unforced MW cleared and the resource clearing prices.

Table 5-13 shows RPM revenue by calendar year for all RPM Auctions held through the first nine months of 2013.

40 The MMU provides detailed analyses of market performance in reports for each RPM Auction. See <http://www.monitoringanalytics.com/reports/Reports/2013.shtml>.

Table 5-11 Capacity prices: 2007/2008 through 2016/2017 RPM Auctions

		RPM Clearing Price ($ per MW-day)									
	Product Type	RTO	MAAC	APS	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI
2007/2008 BRA		$40.80	$40.80	$40.80	$197.67	$188.54	$197.67	$197.67	$197.67	$188.54	
2008/2009 BRA		$111.92	$111.92	$111.92	$148.80	$210.11	$148.80	$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	$10.00	$223.85	
2009/2010 BRA		$102.04	$191.32	$191.32	$191.32	$237.33	$191.32	$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	$86.00	
2010/2011 BRA		$174.29	$174.29	$174.29	$174.29	$174.29	$186.12	$174.29	$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	$50.00	
2011/2012 BRA		$110.00	$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	$55.00	
2011/2012 ATSI FRR Integration Auction		$108.89	$108.89	$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	$5.00	$5.00
2012/2013 BRA		$16.46	$133.37	$16.46	$139.73	$133.37	$222.30	$139.73	$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	$20.46	$20.46
2012/2013 First Incremental Auction		$16.46	$16.46	$16.46	$153.67	$16.46	$153.67	$153.67	$153.67	$16.46	$16.46
2012/2013 Second Incremental Auction		$13.01	$13.01	$13.01	$48.91	$13.01	$48.91	$48.91	$48.91	$13.01	$13.01
2012/2013 Third Incremental Auction		$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51
2013/2014 BRA		$27.73	$226.15	$27.73	$245.00	$226.15	$245.00	$245.00	$245.00	$247.14	$27.73
2013/2014 First Incremental Auction		$20.00	$20.00	$20.00	$178.85	$54.82	$178.85	$178.85	$178.85	$54.82	$20.00
2013/2014 Second Incremental Auction		$7.01	$10.00	$7.01	$40.00	$10.00	$40.00	$40.00	$40.00	$10.00	$7.01
2013/2014 Third Incremental Auction		$4.05	$30.00	$4.05	$188.44	$30.00	$188.44	$188.44	$188.44	$30.00	$4.05
2014/2015 BRA	Limited	$125.47	$125.47	$125.47	$125.47	$125.47	$125.47	$125.47	$213.97	$125.47	$125.47
2014/2015 BRA	Extended Summer	$125.99	$136.50	$125.99	$136.50	$136.50	$136.50	$136.50	$225.00	$136.50	$125.99
2014/2015 BRA	Annual	$125.99	$136.50	$125.99	$136.50	$136.50	$136.50	$136.50	$225.00	$136.50	$125.99
2014/2015 First Incremental Auction	Limited	$0.03	$5.23	$0.03	$5.23	$5.23	$5.23	$5.23	$399.62	$5.23	$0.03
2014/2015 First Incremental Auction	Extended Summer	$5.54	$16.56	$5.54	$16.56	$16.56	$16.56	$16.56	$410.95	$16.56	$5.54
2014/2015 First Incremental Auction	Annual	$5.54	$16.56	$5.54	$16.56	$16.56	$16.56	$16.56	$410.95	$16.56	$5.54
2014/2015 Second Incremental Auction	Limited	$25.00	$56.94	$25.00	$56.94	$56.94	$56.94	$56.94	$310.00	$56.94	$25.00
2014/2015 Second Incremental Auction	Extended Summer	$25.00	$56.94	$25.00	$56.94	$56.94	$56.94	$56.94	$310.00	$56.94	$25.00
2014/2015 Second Incremental Auction	Annual	$25.00	$56.94	$25.00	$56.94	$56.94	$56.94	$56.94	$310.00	$56.94	$25.00
2015/2016 BRA	Limited	$118.54	$150.00	$118.54	$150.00	$150.00	$150.00	$150.00	$150.00	$150.00	$304.62
2015/2016 BRA	Extended Summer	$136.00	$167.46	$136.00	$167.46	$167.46	$167.46	$167.46	$167.46	$167.46	$322.08
2015/2016 BRA	Annual	$136.00	$167.46	$136.00	$167.46	$167.46	$167.46	$167.46	$167.46	$167.46	$357.00
2015/2016 First Incremental Auction	Limited	$43.00	$111.00	$43.00	$111.00	$111.00	$111.00	$122.95	$122.95	$111.00	$168.37
2015/2016 First Incremental Auction	Extended Summer	$43.00	$111.00	$43.00	$111.00	$111.00	$111.00	$122.95	$122.95	$111.00	$168.37
2015/2016 First Incremental Auction	Annual	$43.00	$111.00	$43.00	$111.00	$111.00	$111.00	$122.95	$122.95	$111.00	$168.37
2016/2017 BRA	Limited	$59.37	$119.13	$59.37	$119.13	$119.13	$119.13	$219.00	$219.00	$119.13	$94.45
2016/2017 BRA	Extended Summer	$59.37	$119.13	$59.37	$119.13	$119.13	$119.13	$219.00	$219.00	$119.13	$114.23
2016/2017 BRA	Annual	$59.37	$119.13	$59.37	$119.13	$119.13	$119.13	$219.00	$219.00	$119.13	$114.23

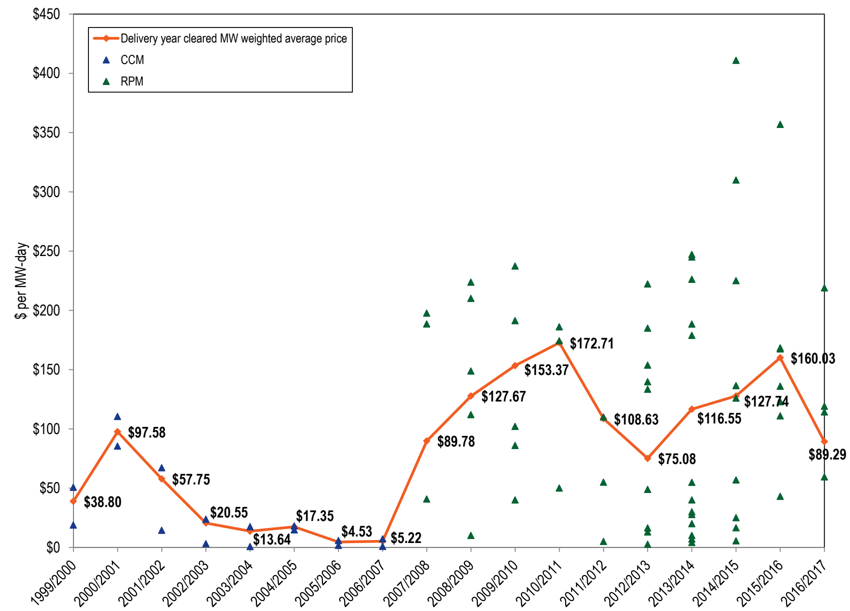
Table 5-12 RPM revenue by type: 2007/2008 through 2016/2017[41,42]

				Coal		Gas		Hydroelectric		Nuclear		Oil		Solar		Solid waste		Wind		
	Demand Resources	Energy Efficiency Resources	Imports	Existing	New/repower/reactivated	Existing	New/repower/reactivated	Existing	New/repower/reactivated	Existing	New/repower/reactivated	Existing	New/repower/reactivated	Existing	New/repower/reactivated	Existing	New/repower/reactivated	Existing	New/repower/reactivated	Total revenue
2007/2008	$5,537,085	$0	$22,225,980	$1,022,372,301	$0	$1,458,989,006	$3,472,667	$209,490,444	$0	$996,085,233	$0	$502,172,373	$0	$0	$0	$31,512,230	$0	$430,065	$0	$4,252,287,381
2008/2009	$35,349,116	$0	$60,918,903	$1,844,120,476	$0	$1,910,349,518	$9,751,112	$287,850,403	$0	$1,322,601,837	$0	$572,259,505	$4,837,523	$0	$0	$35,011,991	$0	$1,180,153	$2,917,048	$6,087,147,586
2009/2010	$65,762,003	$0	$56,517,793	$2,417,576,805	$1,854,781	$2,275,446,414	$30,168,831	$364,742,517	$0	$1,517,723,628	$0	$715,618,319	$5,676,582	$0	$0	$42,758,762	$523,739	$2,011,156	$6,836,827	$7,503,218,157
2010/2011	$60,235,796	$0	$106,046,871	$2,662,434,386	$3,168,069	$2,586,971,699	$58,065,964	$442,429,815	$0	$1,799,258,125	$0	$668,505,533	$4,339,539	$0	$0	$40,731,606	$413,503	$1,819,413	$15,232,177	$8,449,652,496
2011/2012	$55,795,785	$139,812	$185,421,273	$1,595,707,479	$28,330,047	$1,607,317,731	$98,448,693	$278,529,660	$0	$1,079,386,338	$0	$368,084,004	$967,887	$0	$66,978	$25,636,836	$261,690	$1,072,929	$9,919,881	$5,335,087,023
2012/2013	$264,387,897	$11,408,552	$13,260,822	$1,016,194,603	$7,568,127	$1,079,413,451	$76,633,409	$179,117,975	$11,397	$762,719,550	$0	$423,957,756	$2,772,987	$0	$1,246,337	$26,840,670	$316,420	$812,644	$5,052,036	$3,871,714,635
2013/2014	$558,715,114	$21,598,174	$31,804,645	$1,745,438,458	$12,950,135	$1,846,432,716	$167,844,235	$308,853,673	$25,708	$1,346,223,419	$0	$689,864,789	$5,670,399	$0	$3,523,555	$43,943,130	$1,977,705	$1,373,205	$13,538,988	$6,799,778,047
2014/2015	$672,042,592	$41,075,583	$131,766,080	$1,915,786,864	$57,078,818	$1,977,669,867	$188,665,243	$329,051,834	$6,591,114	$1,460,153,171	$0	$473,230,023	$4,101,872	$0	$3,525,901	$34,529,651	$1,694,126	$1,524,551	$32,682,583	$7,331,169,873
2015/2016	$882,512,351	$55,664,349	$190,102,852	$2,779,290,152	$63,163,731	$2,475,378,226	$529,577,871	$385,193,684	$14,880,302	$1,849,263,911	$0	$566,555,231	$5,243,967	$0	$4,526,101	$35,716,918	$4,258,208	$1,829,269	$41,406,297	$9,884,563,419
2016/2017	$437,607,477	$35,346,456	$157,012,514	$1,259,270,875	$42,487,007	$1,461,069,582	$498,909,311	$218,627,999	$10,031,353	$1,002,422,494	$0	$327,077,318	$4,026,475	$0	$4,868,047	$28,668,947	$3,780,862	$1,144,873	$20,886,259	$5,513,237,849

Table 5-13 RPM revenue by calendar year: 2007 through 2017[43]

Year	Weighted Average RPM Price ($ per MW-day)	Weighted Average Cleared UCAP (MW)	Effective Days	RPM Revenue
2007	$89.78	129,409.2	214	$2,486,310,108
2008	$111.93	130,223.2	366	$5,334,880,241
2009	$142.74	132,772.0	365	$6,917,391,702
2010	$164.71	134,033.9	365	$8,058,113,907
2011	$135.14	134,105.2	365	$6,615,032,130
2012	$89.01	137,684.7	366	$4,485,656,150
2013	$99.39	154,044.3	365	$5,588,442,225
2014	$123.11	158,258.0	365	$7,111,333,803
2015	$146.67	164,609.3	365	$8,812,393,764
2016	$118.67	168,936.9	366	$7,337,483,492
2017	$89.29	169,159.7	151	$2,280,818,946

Figure 5-4 History of PJM capacity prices: 1999/2000 through 2016/2017[44]



41 A resource classified as "new/repower/reactivated" is a capacity resource addition since the implementation of RPM and is considered "new/repower/reactivated" for its initial offer and all its subsequent offers in RPM Auctions.

42 The results for the ATSI Integration Auctions are not included in this table.

43 The results for the ATSI Integration Auctions are not included in this table.

44 1999/2000-2006/2007 capacity prices are CCM combined market, weighted average prices. The 2007/2008-2016/2017 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. For the 2014/2015 Delivery Year and forward, only the prices for Annual Resources are plotted.

Figure 5-5 Map of RPM capacity prices: 2013/2014 through 2016/2017

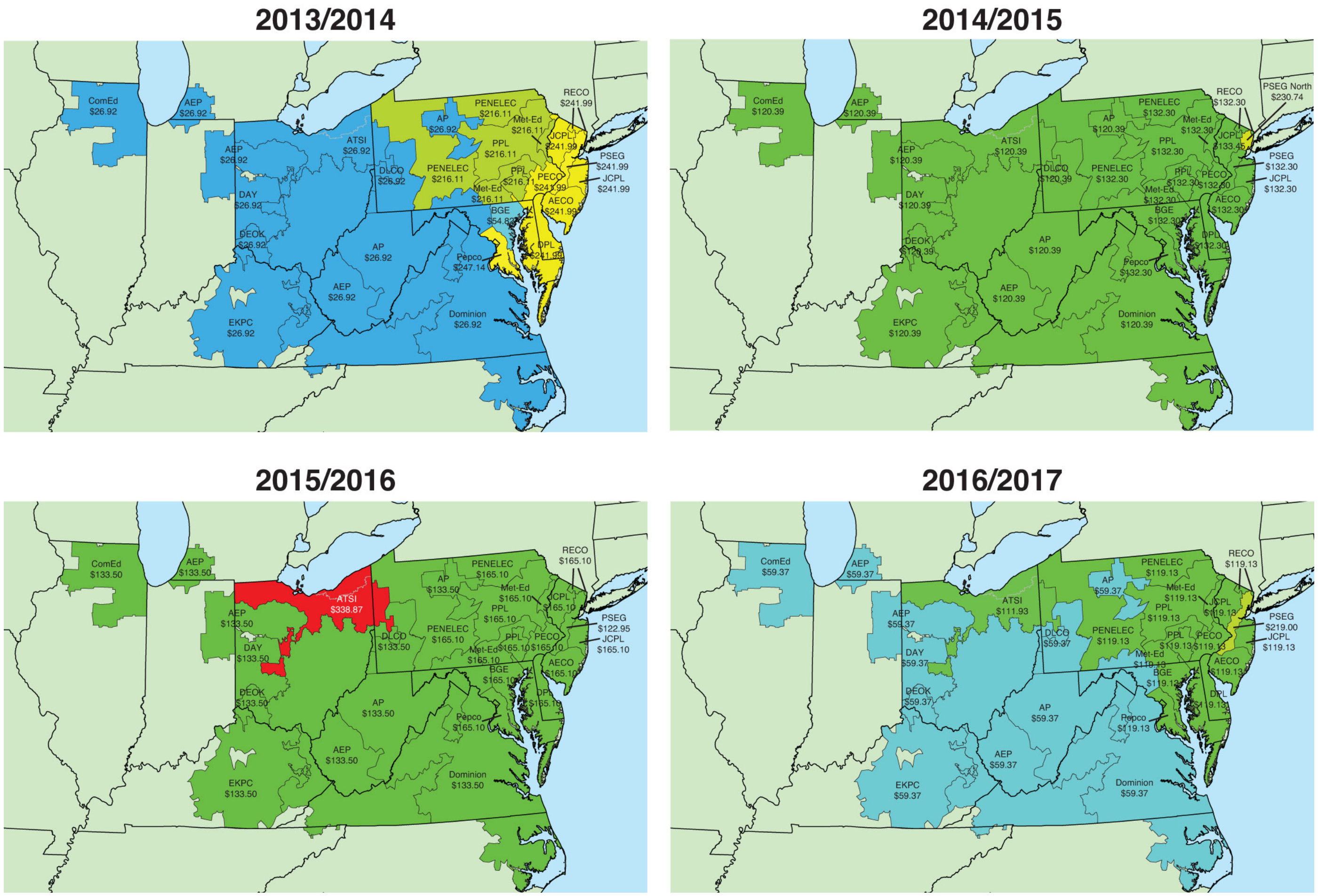


Table 5-14 shows the RPM annual charges to load. For the 2013/2014 planning year, RPM annual charges to load total approximately $6.7 billion.

Table 5-14 RPM cost to load: 2012/2013 through 2016/2017 RPM Auctions[45,46,47]

	Net Load Price ($ per MW-day)	UCAP Obligation (MW)	Annual Charges
2012/2013			
Rest of RTO	$16.74	65,495.4	$400,296,161
Rest of MAAC	$133.42	30,107.9	$1,466,181,230
Rest of EMAAC	$143.06	19,954.6	$1,041,932,095
DPL	$171.27	4,523.9	$282,806,394
PSEG	$157.73	11,645.3	$670,441,158
Total		131,727.1	$3,861,657,038
2013/2014			
Rest of RTO	$28.45	80,012.1	$830,802,258
Rest of MAAC	$232.55	14,623.8	$1,241,276,219
EMAAC	$248.30	36,094.7	$3,271,227,460
Rest of SWMAAC	$231.58	7,925.5	$669,900,300
Pepco	$244.94	7,525.2	$672,777,842
Total		146,181.3	$6,685,984,079
2014/2015			
Rest of RTO	$129.28	81,309.3	$3,836,841,975
Rest of MAAC	$138.36	30,331.6	$1,531,762,816
Rest of EMAAC	$138.36	20,118.8	$1,016,059,638
DPL	$146.14	4,593.1	$244,995,176
PSEG	$171.46	11,669.9	$730,342,563
Total		148,022.7	$7,360,002,168
2015/2016			
Rest of RTO	$135.72	83,538.3	$4,149,635,361
Rest of MAAC	$166.40	55,889.0	$3,403,719,326
PSEG	$166.18	11,787.4	$716,915,782
ATSI	$295.97	14,786.2	$1,601,698,117
Total		166,000.8	$9,871,968,586
2016/2017			
Rest of RTO	$59.37	88,722.2	$1,922,615,128
Rest of MAAC	$118.89	57,413.6	$2,491,443,430
PSEG	$177.61	12,055.9	$781,575,871
ATSI	$90.54	15,121.1	$499,720,114
Total		173,312.9	$5,695,354,543

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

46 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.

47 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 2014/2015, 2015/2016, and 2016/2017 Net Load Prices are not finalized. The 2014/2015, 2015/2016, and 2016/2017 Obligation MW are not finalized.

Replacement Capacity

The IMM's review and analysis of replacement capacity activity is the issue source for the problem statement/issue charge which is currently being discussed in the PJM stakeholder process.[48,49] The IMM proposed a solution package at the Capacity Senior Task Force (CSTF) which includes increasing the Capacity Resource Deficiency Charge; modifying how PJM releases capacity in Incremental Auctions; defining the First and Second Incremental Auction as not mandatory and held due to increases in the Reliability Requirement exceeding certain thresholds; and adding a Market Seller Offer Cap option for First and Second Incremental Auctions, if held, of 1.0 times the Base Residual Auction clearing price. The IMM also recommends that the rules governing the requirement to be a physical resource are enforced.[50]

Generator Performance

Generator performance results from the interaction between the physical characteristics of the units and the level of expenditures made to maintain the capability of the units, which in turn is a function of incentives from energy, ancillary services and capacity markets. Generator performance indices include those based on total hours in a period (generator performance factors) and those based on hours when units are needed to operate by the system operator (generator forced outage rates).[51]

Capacity Factor

Capacity factor measures the actual output of a power plant over a period of time compared to the potential output of the unit had it been running at full nameplate capacity during that period. In the first nine months of 2013, nuclear units had a capacity factor of 93.8 percent, compared to 92.7 percent in the first nine months of 2012. Combined cycle units ran less often,

48 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2012," <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Report_Replacement_Capacity_Activity_20121211.pdf> (December 18, 2012).

49 The Replacement Capacity Issue Charge and Problem Statement were presented at the March 6, 2013 MIC meeting. See "Item 04B – Replacement Capacity Issue Charge," < http://www.pjm.com/~/media/committees-groups/committees/mic/20130306/20130306-item-04b-replacement-capacity-issue-charge.ashx>.

50 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2013" <http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Report_on_Capacity_Replacement_Activity_2_20130913.pdf> (September 13, 2013).

51 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM 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.

decreasing from a percent capacity factor of 62.9 percent in the first nine months of 2012 to 52.9 in the first nine months of 2013. The capacity factor for steam units, which are primarily coal fired, increased from 45.5 percent in the first nine months of 2012 to 49.8 percent in the first nine months of 2013.

Table 5-15 PJM capacity factor (By unit type (GWh)): January through September 2012 and 2013[52,53]

	Jan-Sep 2012		Jan-Sep 2013	
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor
Battery	0.2	0.1%	0.4	0.2%
Combined Cycle	108,088.4	62.9%	90,466.4	52.9%
Combustion Turbine	7,273.8	3.7%	6,585.0	3.3%
Diesel	461.1	15.7%	451.8	16.2%
Diesel (Landfill gas)	913.4	41.2%	1,012.2	41.6%
Fuel Cell	5.7	76.5%	63.4	32.3%
Nuclear	205,503.9	92.7%	207,254.4	93.8%
Pumped Storage Hydro	5,097.0	14.1%	5,297.4	14.7%
Run of River Hydro	4,671.2	29.5%	5,847.2	36.5%
Solar	192.7	16.9%	288.4	17.7%
Steam	261,408.8	45.5%	273,138.1	49.8%
Wind	8,944.7	25.2%	10,379.3	24.9%
Total	602,560.9	47.8%	600,784.1	48.4%

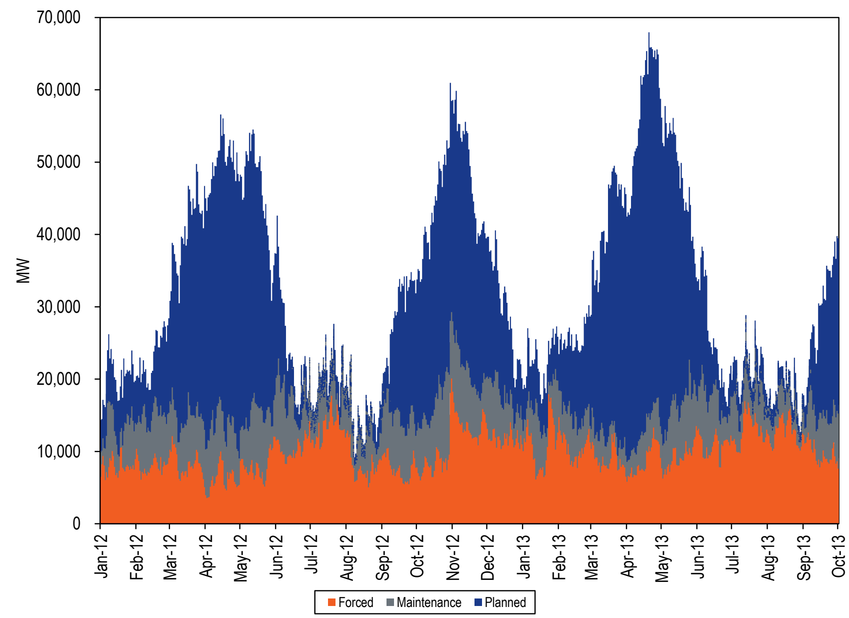
Generator Performance Factors

Generator outages fall into three categories: planned, maintenance, and forced. The amount of MW on outages varies throughout the year. For example, the MW on planned outages are generally highest in the spring and fall, as shown in Figure 5-6, due to restrictions on planned outages during the winter and summer. The effect of seasonal variation in outages can be seen in the monthly generator performance metrics in "Performance By Month."

52 The capacity factors for wind and solar unit types described in this table are based on nameplate capacity values, and are calculated based on when the units come online.

53 The EKPC Transmission Zone was integrated on June 1, 2013 and is included in the January through September numbers for 2013.

Figure 5-6 PJM outages (MW): January 2012 to September 2013



Performance factors include the equivalent availability factor (EAF), the equivalent maintenance outage factor (EMOF), the equivalent planned outage factor (EPOF) and the equivalent forced outage factor (EFOF). These four factors add to 100 percent for any generating unit. The EAF is the proportion of hours in a year when a unit is available to generate at full capacity while the three outage factors include all the hours when a unit is unavailable. The EMOF is the proportion of hours in a year when a unit is unavailable because of maintenance outages and maintenance deratings. The EPOF is the proportion of hours in a year when a unit is unavailable because of planned outages and planned deratings. The EFOF is the proportion of hours in a year when a unit is unavailable because of forced outages and forced deratings.

The PJM aggregate EAF, EFOF, EPOF, and EMOF are shown in Figure 5-7. Metrics by unit type are shown in Table 5-16 through Table 5-19.

Figure 5-7 PJM equivalent outage and availability factors: 2007 to 2013

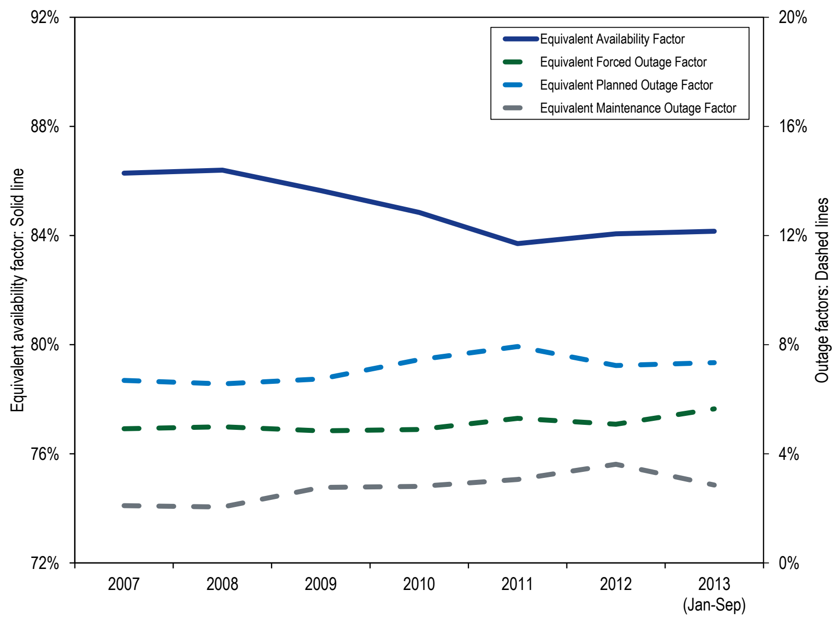


Table 5-16 EAF by unit type: 2007 through September 2013

	2007	2008	2009	2010	2011	2012	2013 (Jan-Sep)
Combined Cycle	89.7%	90.2%	87.8%	85.9%	85.4%	85.4%	86.2%
Combustion Turbine	90.5%	91.1%	93.2%	93.1%	91.8%	92.4%	90.7%
Diesel	86.4%	87.8%	91.2%	94.1%	94.8%	92.5%	93.7%
Hydroelectric	90.1%	88.8%	86.9%	88.8%	84.6%	88.8%	89.6%
Nuclear	93.1%	92.3%	90.1%	91.8%	90.1%	91.1%	92.4%
Steam	81.3%	81.6%	80.9%	79.0%	78.2%	77.9%	77.4%
Total	86.3%	86.4%	85.6%	84.8%	83.7%	84.1%	84.2%

Table 5-17 EMOF by unit type: 2007 through September 2013

	2007	2008	2009	2010	2011	2012	2013 (Jan-Sep)
Combined Cycle	2.0%	1.6%	3.0%	3.1%	2.4%	2.7%	2.6%
Combustion Turbine	2.5%	2.2%	2.3%	2.0%	2.4%	1.7%	1.6%
Diesel	1.8%	1.2%	1.2%	1.5%	2.0%	2.6%	1.4%
Hydroelectric	1.4%	2.1%	2.3%	1.9%	1.9%	2.1%	1.6%
Nuclear	0.3%	0.8%	0.6%	0.5%	1.2%	1.1%	0.8%
Steam	2.7%	2.6%	3.7%	3.9%	4.2%	5.6%	4.3%
Total	2.1%	2.1%	2.8%	2.8%	3.1%	3.6%	2.9%

Table 5-18 EPOF by unit type: 2007 through September 2013

	2007	2008	2009	2010	2011	2012	2013 (Jan-Sep)
Combined Cycle	5.9%	6.0%	6.3%	8.2%	9.6%	8.3%	8.3%
Combustion Turbine	2.5%	4.0%	2.8%	3.0%	3.8%	3.2%	2.7%
Diesel	0.7%	1.1%	0.6%	0.5%	0.1%	0.7%	0.3%
Hydroelectric	7.2%	7.8%	8.6%	8.6%	11.8%	6.3%	6.8%
Nuclear	5.3%	5.1%	5.2%	5.4%	6.1%	6.4%	5.6%
Steam	8.6%	8.0%	8.6%	9.4%	9.2%	8.7%	9.5%
Total	6.7%	6.6%	6.7%	7.5%	7.9%	7.2%	7.3%

Table 5-19 EFOF by unit type: 2007 through June 2013

	2007	2008	2009	2010	2011	2012	2013 (Jan-Sep)
Combined Cycle	2.3%	2.3%	2.9%	2.7%	2.6%	3.6%	2.8%
Combustion Turbine	4.5%	2.7%	1.6%	1.9%	2.0%	2.8%	5.1%
Diesel	11.2%	9.9%	7.0%	3.8%	3.2%	4.2%	4.6%
Hydroelectric	1.3%	1.3%	2.3%	0.7%	1.7%	2.8%	2.0%
Nuclear	1.3%	1.8%	4.1%	2.3%	2.6%	1.5%	1.2%
Steam	7.3%	7.9%	6.8%	7.7%	8.3%	7.8%	8.7%
Total	4.9%	5.0%	4.8%	4.9%	5.3%	5.1%	5.6%

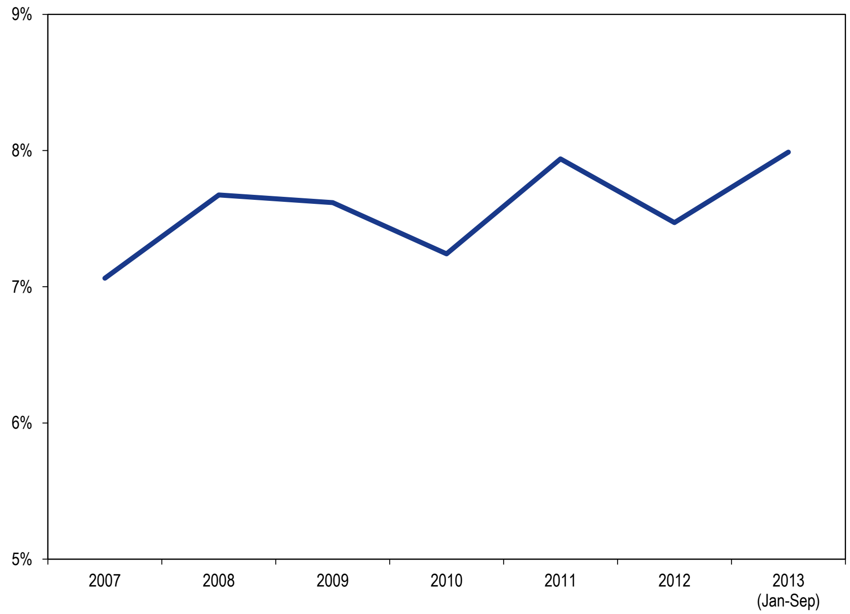
Generator Forced Outage Rates

There are three primary forced outage rate metrics. The most fundamental forced outage rate metric is EFORd. The other forced outage rate metrics either exclude some outages, XEFORd, or exclude some outages and exclude some time periods, EFORp.

The unadjusted forced outage rate of a generating unit is measured as the equivalent demand forced outage rate (EFORd). EFORd is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate. EFORd measures the forced outage rate during periods of demand, and does not include planned or maintenance outages. A period of demand is a period during which a generator is running or needed to run. EFORd calculations use historical performance data, including equivalent forced outage hours, service hours, average forced outage duration, average run time, average time between unit starts, available hours and period hours.[54] The EFORd metric includes all forced outages, regardless of the reason for those outages.

Figure 5-8 shows the average EFORd since 2007 for all units in PJM.

Figure 5-8 Trends in the PJM equivalent demand forced outage rate (EFORd): 2007 through 2013



54 Equivalent forced outage hours are the sum of all forced outage hours in which a generating unit is fully inoperable and all partial forced outage hours in which a generating unit is partially inoperable prorated to represent full hours.

Table 5-20 shows the class average EFORd by unit type.

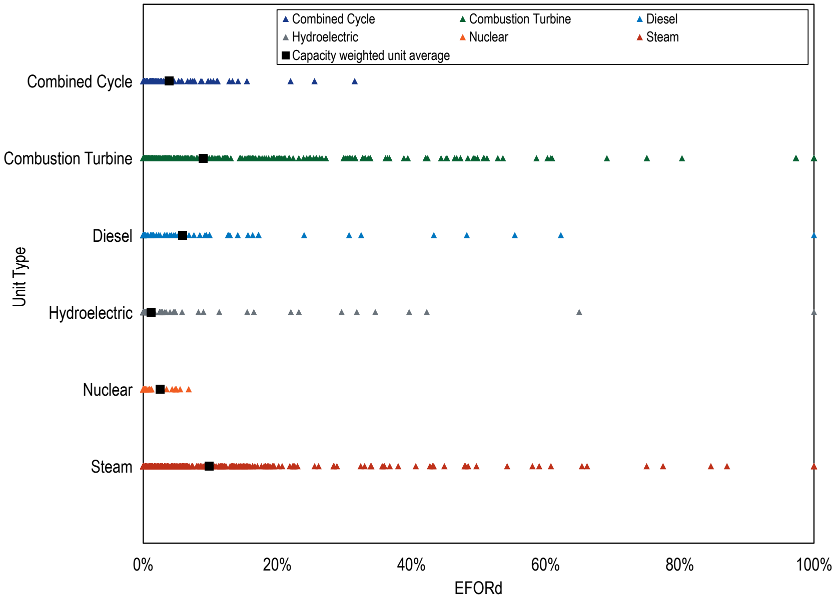
Table 5-20 PJM EFORd data for different unit types: 2007 through September 2013

	2007	2008	2009	2010	2011	2012	2013 (Jan-Sep)
Combined Cycle	3.8%	3.9%	4.3%	3.9%	3.5%	4.3%	3.5%
Combustion Turbine	11.1%	11.1%	9.8%	8.9%	8.0%	8.2%	10.1%
Diesel	12.9%	11.2%	9.9%	5.9%	9.6%	5.5%	5.1%
Hydroelectric	2.0%	2.0%	3.2%	1.2%	2.9%	4.4%	3.1%
Nuclear	1.4%	1.9%	4.1%	2.5%	2.8%	1.6%	1.3%
Steam	9.2%	10.1%	9.4%	9.8%	11.3%	10.6%	11.6%
Total	7.1%	7.7%	7.6%	7.2%	7.9%	7.5%	8.0%

Distribution of EFORd

The average EFORd results do not show the underlying pattern of EFORd rates within each unit type. The distribution of EFORd by unit type is shown in Figure 5-9. Each generating unit is represented by a single point, and the capacity weighted unit average is represented by a solid square. Combustion turbine units had the greatest variance of EFORd, while nuclear units had the lowest variance in EFORd values in the first nine months of 2013.

Figure 5-9 PJM distribution of EFORd data by unit type: January through September 2013



Other Forced Outage Rate Metrics

There are two additional primary forced outage rate metrics that play a significant role in PJM markets, XEFORd and EFORp. The XEFORd metric is the EFORd metric adjusted to remove outages that have been defined to be outside management control (OMC). The EFORp metric is the EFORd metric adjusted to remove OMC outages and to reflect unit availability only during the approximately 500 hours defined in the PJM RPM tariff to be the critical load hours.

The PJM capacity market rules use XEFORd to determine the UCAP for generating units. Unforced capacity in the PJM Capacity Market for any individual generating unit is equal to one minus the XEFORd multiplied by the unit ICAP.

All outages, including OMC outages, are included in the EFORd that is used for planning studies that determine the reserve requirement. However, OMC outages are excluded from the calculations of XEFORd, which are used to determine the level of unforced capacity for specific units that must be offered in PJM's Capacity Market.

The PJM Capacity Market creates an incentive to minimize the forced outage rate excluding OMC outages, but not an incentive to minimize the forced outage rate accounting for all forced outages. In fact, because PJM uses XEFORd as the outage metric to define capacity available for sale, the PJM Capacity Market includes an incentive to classify as many forced outages as possible as OMC.

Outages Deemed Outside Management Control

In 2006, NERC created specifications for certain types of outages deemed to be Outside Management Control (OMC).[55] For NERC, an outage can be classified as an OMC outage only if the outage meets the requirements outlined in Appendix K of the "Generator Availability Data System Data Reporting Instructions." Appendix K of the "Generator Availability Data Systems Data Reporting Instructions" also lists specific cause codes (codes that are standardized for specific outage causes) that would be considered OMC outages.[56] Not all outages caused by the factors in these specific OMC cause codes are OMC outages. For example, according to the NERC specifications, fuel quality issues (codes 9200 to 9299) may be within the control of the owner or outside management control. Each outage must be considered separately per the NERC directive.

55 Generator Availability Data System Data Reporting Instructions states, "The electric industry in Europe and other parts of the world has made a change to examine losses of generation caused by problems with and outside plant management control... There are a number of outage causes that may prevent the energy coming from a power generating plant from reaching the customer. Some causes are due to the plant operation and equipment while others are outside plant management control. The standard sets a boundary on the generator side of the power station for the determination of equipment outside management control." The Generator Availability Data System Data Reporting Instructions can be found on the NERC website: <http://www.nerc.com/files/2009_GADS_DRI_Complete_SetVersion_010111.pdf>.

56 For a list of these cause codes, see the *Technical Reference for PJM Markets*, at "Generator Performance: NERC OMC Outage Cause Codes" <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

Nothing in NERC's classification of outages requires that PJM exclude OMC outages from the forced outage rate metric used in the Capacity Market.[57] That choice was made by PJM and can be modified without violating any NERC requirements.[58] It is possible to have an OMC outage under the NERC definition, which PJM does not define as OMC for purposes of calculating XEFORd. That is the current PJM practice. The actual implementation of the OMC outages and their impact on XEFORd is and has been within the control of PJM. PJM has chosen to exclude only some of the OMC outages from the XEFORd metric.

At present, PJM does not have a clear, documented, public set of criteria for designating outages as OMC.

All outages, including OMC outages, are included in the EFORd that is used for PJM planning studies that determine the reserve requirement. However, OMC outages are excluded from the calculations used to determine the level of unforced capacity for specific units that must be offered in PJM's Capacity Market. This modified EFORd is termed the XEFORd. Table 5-21 shows OMC forced outages by cause code, as classified by PJM. OMC forced outages account for 34.3 percent of all forced outages. The second-largest contributor to OMC outages, lack of fuel, was the cause in of 28.0 percent of OMC outages and 9.6 percent of all forced outages. The NERC GADS guidelines in Appendix K describe OMC lack of fuel as "lack of fuel where the operator is not in control of contracts, supply lines, or delivery of fuels."

The largest contributor to OMC outages, hurricane, affected a number of large units in the early spring. Also contributing to hurricane outages were several units that have been on outage since the 2012 hurricane.

57 For example, the NYISO does not classify any fuel related outages or derates as OMC under its capacity market rules. See New York Independent System Operator, "Manual 4: Installed Capacity Manual," Version 6.20. (January, 24 2012) <http://www.nyiso.com/public/webdocs/documents/manuals/operations/icap_mnl.pdf> When a Generator, Energy/Capacity Limited Resource, System Resource, Intermittent Power Resource or Control Area System Resource is forced into an outage by an equipment failure that involves equipment located on the electric network beyond the step-up transformer, and including such step-up transformer, the NYISO shall not treat the outage as a forced outage for purposes of calculating the amount of Unforced Capacity such Installed Capacity Suppliers are qualified to supply in the NYCA. This exception is limited to an equipment failure that involves equipment located on the electric network beyond the generator step-up transformer, and including such step-up transformer on the output side of the Generator, Energy/Capacity Limited Resource, System Resource, Intermittent Power Resource or Control Area System Resource. This exception does not apply to fuel related outages or derates or other cause codes that might be classified as Outside Management Control in the NERC Data reporting Instructions. NYISO only accepts OMC outages for outages at or beyond the step-up transformer.

58 It is unclear whether there were member votes taken on this issue prior to PJM's implementation of its approach to OMC outages. It does not appear that PJM has consulted with members for the subsequent changes to its application of OMC outages.

Table 5-21 OMC Outages: January through September 2013

OMC Cause Code	Percent of OMC Forced Outages	Percent of all Forced Outages
Hurricane	41.2%	14.1%
Lack of fuel	28.0%	9.6%
Flood	14.3%	4.9%
Transmission system problems other than catastrophes	5.2%	1.8%
Lightning	4.4%	1.5%
Other switchyard equipment external	1.5%	0.5%
Switchyard circuit breakers external	1.3%	0.5%
Transmission line	1.2%	0.4%
Other miscellaneous external problems	0.7%	0.2%
Transmission equipment beyond the 1st substation	0.5%	0.2%
Lack of water	0.5%	0.2%
Storms	0.4%	0.1%
Transmission equipment at the 1st substation	0.3%	0.1%
Frozen coal	0.1%	0.0%
Switchyard system protection devices	0.1%	0.0%
Switchyard transformers and associated cooling systems	0.1%	0.0%
Other fuel quality problems	0.1%	0.0%
Tornados	0.0%	0.0%
Miscellaneous regulatory	0.0%	0.0%
Wet coal	0.0%	0.0%
Other catastrophe	0.0%	0.0%
Total	100.0%	34.3%

An outage is an outage, regardless of the cause. Lack of fuel is especially noteworthy because, even if the OMC concept were accepted, the lack of fuel reasons are not outside the control of management. Virtually any issue with fuel supply can be addressed by additional expenditures. These are economic issues within the control of management and the resultant tradeoffs should be reflected in actual forced outage rates rather than ignored by designation as OMC. It is significant that some OMC outages are classified as economic. Firm gas contracts could be used in place of interruptible gas contracts. Alternative fuels could be used as a supplement to primary fuels. Improved fuel management practices including additional investment could eliminate wet coal as a reason. Better diversification in supplies could eliminate interruptions from individual suppliers. But regardless of the reason, an outage is an outage. If a particular unit or set of units have outages on a regular basis for one of the OMC reasons, that is a real feature of the units that should be reflected in overall PJM system planning as well as in the economic fundamentals of the capacity market and the capacity market outcomes. Permitting OMC outages to be excluded from the forced outage metric skews the results of the capacity market towards less reliable units and away from more reliable units. This is exactly the wrong incentive. Paying for capacity from units using the EFORd, not the XEFORd, metric would provide a market incentive for unit owners to address all their outage issues in an efficient manner. Pretending that some outages simply do not exist distorts market outcomes. That is exactly the result of using OMC outages to reduce EFORd.[59]

If there were units in a constrained Locational Deliverability Area (LDA) that regularly had a higher rate of OMC outages than other units in the LDA and in PJM, and that cleared in the capacity auctions, the supply and demand in that LDA would be affected. The payments to the high OMC units would be too high and the payments to other units in the LDA would be too low. This market signal, based on the exclusion of OMC outages, favors generating units with high forced outage rates that result from causes classified as OMC, compared to generating units with no OMC outages.

With the OMC rules in place, if a new unit were considering entry into a constrained LDA and had choices about the nature of its fuel supply, the unit would not have an incentive to choose the most reliable fuel source or combination of fuel sources, but simply the cheapest. The OMC outage rules would provide the wrong incentive. While it is up to the generation investor to determine its fuel supply arrangements, the generation investor must also take on the risks associated with its fuel supply decisions rather than being able to shift those risks to other generation owners and to customers, which is exactly what occurs under the OMC rules as currently implemented. This issue is especially critical in a time when almost all incremental conventional generation in PJM is gas fired.

The MMU recommends that PJM immediately eliminate lack of fuel as an acceptable basis for an OMC outage. The MMU recommends that PJM eliminate all OMC outages from the calculation of forced outage rates used for any purpose in the PJM Capacity Market after appropriate notice.

All submitted OMC outages are reviewed by PJM's Resource Adequacy Department. The MMU recommends that pending elimination of OMC outages, PJM review all requests for OMC carefully, develop a clear, transparent set of written public rules governing the designation of outages as OMC and post those guidelines. Any resultant OMC outages may be considered by PJM but should not be reflected in forced outage metrics which affect system planning or market payments to generating units.

Forced Outage Analysis

The MMU analyzed the causes of forced outages for the entire PJM system. The metric used was lost generation, which is the product of the duration of the outage and the size of the outage reduction. Lost generation can be converted into lost system equivalent availability.[60] On a systemwide basis, the resultant lost equivalent availability from the forced outages is equal to the equivalent forced outage factor.

PJM EFOF was 5.6 percent in 2013. This means there was 5.6 percent lost availability because of forced outages. Table 5-22 shows that forced outages for boiler tube leaks, at 16.8 percent of the systemwide EFOF, were the largest single contributor to EFOF.

59 For more on this issue, see the IMM's White Paper included in: Monitoring Analytics, LLC and PJM Interconnection, LLC, *"Capacity in the PJM Market,"* <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_And_PJM_Capacity_White_Papers_On_OPSI_Issues_20120820.pdf> (August 20, 2012)

60 For any unit, lost generation can be converted to lost equivalent availability by dividing lost generation by the product of the generating units' capacity and period hours. This can also be done on a systemwide basis.

Table 5-22 Contribution to EFOF by unit type by cause: January through September 2013

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	System
Boiler Tube Leaks	5.1%	0.0%	0.0%	0.0%	0.0%	21.4%	16.8%
Catastrophe	5.9%	56.0%	7.6%	1.4%	20.7%	4.6%	11.5%
Boiler Piping System	4.0%	0.0%	0.0%	0.0%	0.0%	6.2%	5.0%
Economic	0.9%	8.2%	4.9%	1.6%	0.0%	4.3%	4.4%
High Pressure Turbine	32.6%	0.0%	0.0%	0.0%	0.0%	3.2%	4.3%
Boiler Air and Gas Systems	0.0%	0.0%	0.0%	0.0%	0.0%	5.5%	4.2%
Feedwater System	0.7%	0.0%	0.0%	0.0%	6.4%	4.0%	3.4%
Electrical	1.7%	1.8%	6.4%	8.1%	6.1%	3.4%	3.2%
Miscellaneous (Steam Turbine)	3.1%	0.0%	0.0%	0.0%	0.1%	3.6%	2.9%
Boiler Fuel Supply from Bunkers to Boiler	0.1%	0.0%	0.0%	0.0%	0.0%	2.9%	2.3%
Controls	3.2%	5.6%	0.1%	0.6%	3.9%	1.0%	1.8%
Circulating Water Systems	2.1%	0.0%	0.0%	0.0%	6.8%	1.4%	1.4%
Slag and Ash Removal	0.0%	0.0%	0.0%	0.0%	0.0%	3.6%	2.8%
Fuel Quality	0.0%	0.1%	4.4%	0.0%	0.0%	1.6%	1.2%
Stack Emission	0.3%	1.4%	0.6%	0.0%	0.0%	3.3%	2.7%
Miscellaneous (External)	5.1%	0.0%	0.5%	70.2%	0.1%	0.0%	1.2%
Boiler Internals and Structures	0.9%	0.0%	0.0%	0.0%	0.0%	1.5%	1.2%
Generator	1.7%	0.3%	5.6%	1.7%	22.0%	0.4%	1.2%
Reserve Shutdown	0.3%	2.7%	25.9%	0.8%	0.0%	4.1%	3.6%
All Other Causes	32.3%	24.0%	44.1%	15.6%	33.9%	24.1%	24.8%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Table 5-23 shows the categories which are included in the economic category.[61] Lack of fuel that is considered Outside Management Control accounted for 81.0 percent of all economic reasons.

Table 5-23 Contributions to Economic Outages: January through September 2013

	Contribution to Economic Reasons
Lack of fuel (OMC)	81.0%
Lack of fuel (Non-OMC)	18.2%
Lack of water (Hydro)	0.5%
Fuel conservation	0.2%
Problems with Primary Fuel for Units with Secondary Fuel Operation	0.1%
Other economic problems	0.0%
Total	100.0%

61 The definitions of these outages are defined by NERC GADS.

OMC lack of fuel is described as "Lack of fuel where the operator is not in control of contracts, supply lines, or delivery of fuels."[62] Only a handful of units use other economic problems to describe outages. Other economic problems are not defined by NERC GADS and are best described as economic problems that cannot be classified by the other NERC GADS economic problem cause codes. Lack of water events occur when a hydroelectric plant does not have sufficient fuel (water) to operate.

EFORd, XEFORd and EFORp

The equivalent forced outage rate during peak hours (EFORp) is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate during the peak hours of the day in the peak months of January, February, June, July and August. EFORp is calculated using historical performance data and is designed to measure if a unit would have run had the unit not been forced out. Like XEFORd, EFORp excludes OMC outages. PJM systemwide EFORp is a capacity-weighted average of individual unit EFORp.

EFORd, XEFORd and EFORp are designed to measure the rate of forced outages, which are defined as outages that cannot be postponed beyond the end of the next weekend.[63] It is reasonable to expect that units have some degree of control over when to take a forced outage, depending on the underlying cause of the forced outage. If units had no control over the timing of forced outages, outages during peak hours of the peak months would be expected to occur at roughly the same rate as outages during periods of demand throughout the rest of the year. With the exception of nuclear units, EFORp is lower than EFORd, suggesting that units elect to

62 The definitions of these outages are defined by NERC GADS.
63 See PJM. "Manual 22: Generator Resource Performance Indices," Revision 16 (November 16, 2011), Definitions.

take forced outages during off-peak hours, as much as it is within their ability to do so. That is consistent with the incentives created by the PJM Capacity Market.

Table 5-24 shows the capacity-weighted class average of EFORd, XEFORd and EFORp. The impact of OMC outages is especially noticeable in the difference between EFORd and XEFORd for steam units and combustion turbine units.

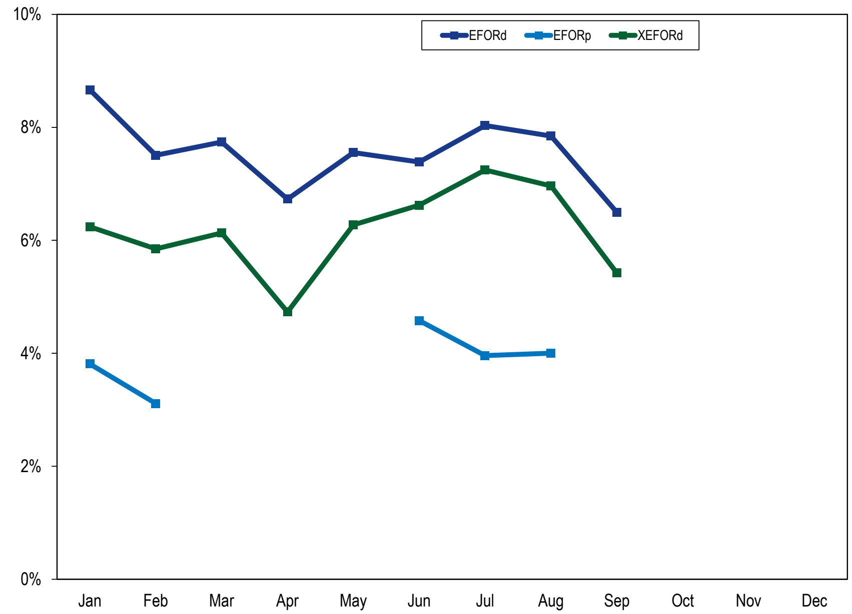
Table 5-24 PJM EFORd, XEFORd and EFORp data by unit type: January through September 2013[64]

	EFORd	XEFORd	EFORp	Difference EFORd and XEFORd	Difference EFORd and EFORp
Combined Cycle	3.5%	3.2%	1.1%	0.4%	2.4%
Combustion Turbine	10.1%	6.3%	3.5%	3.9%	6.6%
Diesel	5.1%	4.6%	1.5%	0.5%	3.6%
Hydroelectric	3.1%	1.0%	0.9%	2.1%	2.2%
Nuclear	1.3%	1.0%	1.2%	0.3%	0.1%
Steam	11.6%	10.2%	6.4%	1.4%	5.2%
Total	8.0%	6.5%	4.0%	1.5%	4.0%

Performance By Month

On a monthly basis, EFORp values were significantly less than EFORd and XEFORd values as shown in Figure 5-10, demonstrating that units had fewer outages during peak hours than would have been expected based on EFORd.

Figure 5-10 PJM EFORd, XEFORd and EFORp: January through September 2013



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

On a monthly basis, unit availability as measured by the equivalent availability factor is shown in Figure 5-11.

Figure 5-11 PJM monthly generator performance factors: January through September 2013