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 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 six months of 2014, 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, the definition of DR which permits inferior products to substitute for capacity, the replacement capacity issue, the inclusion of imports which are not substitutes for internal capacity resources and inadequate performance incentives.

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

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 *2014 Quarterly State of the Market Report for PJM: January through June*, Section 5, "Capacity Market," and include all capacity within the PJM footprint.

5 See 126 FERC ¶ 61,275 (2009) at P 86.

unforced capacity resource shortage exceeded 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.[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. 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, although the performance incentives are inadequate. 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 Resources and Energy Efficiency Resources may be offered directly into RPM Auctions and receive the clearing price without mitigation.

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.

Market Structure

- During the first six months of 2014, PJM installed capacity increased 911.7 MW or 0.5 percent from 183,095.2 MW on January 1 to 184,006.9 MW on June 30. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- Of the total installed capacity on June 30, 2014, 40.6 percent was coal; 29.9 percent was gas; 17.9 percent was nuclear; 6.1 percent was oil; 4.6 percent was hydroelectric; 0.4 percent was wind; 0.4 percent was solid waste; and 0.1 percent was solar.
- In the 2017/2018 RPM Base Residual Auction, all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[8] 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]
- Of the 4,944.7 MW of imports in the 2017/2018 RPM Base Residual Auction, 4,525.5 MW cleared. Of the cleared imports, 2,624.3 MW (58.0 percent) were from MISO.
- Capacity in the RPM load management programs was 9,493.6 MW for June 1, 2014 as a result of cleared capacity for Demand Resources and Energy Efficiency Resources in RPM Auctions for the 2014/2015 Delivery Year (16,020.7 MW) less replacement capacity (6,527.1 MW).

8 There are 27 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).
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).

Market Conduct

- Of the 1,202 generation resources which submitted offers, unit-specific offer caps were calculated for 131 generation resources (10.9 percent). The MMU calculated offer caps for 531 generation resources (44.2 percent), of which 400 were based on the technology specific default (proxy) ACR values.

Market Performance

- The 2017/2018 RPM Base Residual Auction was conducted in the first six months of 2014. In the 2017/2018 RPM Base Residual Auction, the RTO clearing price for Annual Resources was $120.00 per MW-day.
- The weighted average capacity price for the 2014/2015 Delivery Year is $126.40 per MW-day, including all RPM Auctions for the 2014/2015 Delivery Year held through the first six months of 2014.
- The Delivery Year weighted average capacity price was $116.55 per MW-day in 2013/2014.

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd for the first six months of 2014 was 11.2 percent, an increase from 8.6 percent for the first six months of 2013.[12]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor for the first six months of 2014 was 80.3 percent, a decrease from 81.8 percent for the first six months of 2013.
- **Outages Deemed Outside Management Control (OMC).** In the first six months of 2014, 12.9 percent of forced outages were classified as OMC outages, and 22.5 percent of OMC outages were due to lack of fuel. 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.

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 capacity resources in RPM. Data is for the three months ending June 30, 2014, as downloaded from the PJM GADS database on July 27, 2014. 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.

Recommendations[13 14 15 16]

- The MMU recommends the enforcement of a consistent definition of capacity resource. The MMU recommends that the requirement to be a physical resource be enforced and enhanced. The requirement to be a physical resource should apply at the time of auctions and should also constitute a commitment to be physical in the relevant Delivery Year. The requirement to be a physical resource should be applied to all resource types, including planned generation, demand resources and imports.[17 18]
- The MMU recommends that the definition of demand side resources be modified in order to ensure that such resources be fully substitutable for other generation capacity resources. Both the Limited and the Extended Summer DR products should be eliminated in order to ensure that the DR product has the same unlimited obligation to provide capacity year round as generation capacity resources.
- The MMU recommends that the use of the 2.5 percent demand adjustment (Short Term Resource Procurement Target) be terminated immediately. The 2.5 percent should be added back to the overall market demand curve.
- The MMU recommends that the test for determining modeled Locational Deliverability Areas in RPM be redefined. A detailed reliability analysis of all at risk units should be included in the redefined model.
- The MMU recommends that there be an explicit requirement that Capacity Resource offers in the Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units.
- The MMU recommends that clear, explicit operational protocols be defined for recalling the energy output of Capacity Resources when PJM is in an emergency condition. PJM has modified these protocols, but they need additional clarification and operational details.

13 The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues. These recommendations have been made in public reports.
14 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).
15 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).
16 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).
17 See also Comments of the Independent Market Monitor for PJM. Docket No. ER14-503-000 (December 20, 2013).
18 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).

- The MMU recommends improvements to the performance incentive requirements of RPM:
  - The MMU recommends that Generation Capacity Resources be paid on the basis of whether they produce energy when called upon during any of the hours defined as critical. One hundred percent of capacity market revenue should be at risk rather than only fifty percent.
  - The MMU recommends that a unit which is not capable of supplying energy consistent with its day-ahead offer should reflect an appropriate 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.
  - The MMU recommends that PJM eliminate the broad exception related to lack of gas during the winter period for single-fuel, natural gas-fired units.[19]

19 For more on this issue and related incentive issues, 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).

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 six months of 2014. 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 2014.[20]

The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[21] [22] [23] [24] In 2013 and 2014, the MMU prepared a number of RPM-related reports and testimony, shown in Table 5-2.

As an example of such reports, the MMU prepared a report that addresses and quantifies the impact on market outcomes in the Base Residual Auction (BRA) for the 2017/2018 Delivery Year of the Short-Term Resource Procurement Target (2.5 percent offset) and demand side resources both separately and together. (Demand side resources include Demand Resources, DR, and Energy Efficiency resources, EE.) The report demonstrates that the limited DR product and the 2.5 percent offset significantly suppress prices.[25]

20 For more complete conclusions, see *2013 State of the Market Report for PJM*, Section 4, "Capacity Market."

21 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).

22 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).

23 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).

24 See "Analysis of the 2016/2017 RPM Base Residual Auction," < http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Analysis_of_the_20162017_RPM_Base_Residual_Auction_20140418.pdf> (April 18, 2014).

25 The 2017/2018 RPM Base Residual Auction: Sensitivity Analyses, <http://www.monitoringanalytics.com/reports/Reports/2014/IMM_20172018_RPM_BRA_Sensitivity_Analyses_20140710.pdf > (July 10, 2014.)

The MMU continues to recommend that the use of the 2.5 percent demand adjustment be terminated immediately.[26] The 2.5 percent demand reduction is a barrier to entry in the capacity market. The logic of reducing demand in a market design that looks three years forward, to permit other resources to clear in Incremental Auctions, is not supportable and has no basis in economics. There are tradeoffs in using a one year forward or a three year forward design, but the design should be implemented on a consistent basis. Removing a portion of demand affects prices at the margin, which is where the critical signal to the market is determined.

The results of the report show that even when all DR is removed and the 2.5 percent offset is eliminated and holding everything else constant, prices would have risen to greater than net CONE but less than the maximum price and PJM's reliability target would have been maintained. This a measure of the impact of the removal of DR and the 2.5 percent offset and is also a measure of the price suppression effect of DR and the 2.5 percent offset.

The fact that this set of sensitivity analyses holds everything else constant is important for considering the actual impacts of the simultaneous elimination of DR and the 2.5 percent offset. The results of these sensitivity analyses are worst case, in the sense that the increases in prices and reductions in quantities cleared are the maximum levels, because they do not include any market response which would mitigate the impact on prices and cleared quantities of eliminating DR. If both these adjustments had been made prior to the 2017/2018 BRA, it is likely that additional generation resources would have entered the market, that prices would likely have been lower than the prices in these sensitivity analyses and that reliability would have been greater than in these sensitivity analyses.

26 See also the *Protest of the Independent Market Monitor for PJM*, Docket No. ER12-513 (December 22, 2011).

Table 5-2 RPM related MMU reports, 2013 through June, 2014

Date	Name
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
November 27, 2013	IMM Answer and Motion for Leave to Answer re Forward Capacity Market Comment Clarification No. ER11-4081-001 http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Answer_and_Motion_for_Leave_to_Answer_No_ER11-4081-001_20131127.pdf
December 20, 2013	IMM Comments re RPM Import Cap No. ER14-503-000 http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Comments_ER14-503-000_20131220.pdf
December 20, 2013	IMM Comments re Limited DR Cap No. ER14-504-000 http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Comments_ER14-504-000_20131220.pdf
December 20, 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_20131220.pdf
January 8, 2014	IMM Comments re Capacity Technical Conference No. AD13-7-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Comments_AD13-7-000_20140109.pdf
January 8, 2014	IMM Answer re Limited DR Cap No. ER14-504-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Answer_ER14-504-000_20140108.pdf
January 8, 2014	IMM Answer re RPM Import Cap No. ER14-503-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Answer_ER14-503-000_20140108.pdf
January 27, 2014	IMM Complaint and Motion to Consolidate re DR Resources Docket No EL14-xxx-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Complaint_and_Motion_to_Consolidate_EL14-xxx_20140127.pdf
January 29, 2014	IMM Motion for Clarification and/or Reconsideration, or, in the Alternative, Rehearing re Make-Whole Waiver Docket No. ER14-1144-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Motion_for_Clarification_or_Reconsideration_or_Rehearing_ER14-1144-000_20140129.pdf
January 29, 2014	IM Comments re Offer Cap Waiver Docket No. ER14-1145-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Comments_ER14-1145-000_20140129.pdf
February 24, 2014	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_20140224.pdf
March 7, 2014	IMM Comments re January 28 Deficiency Letter Docket No. ER14-503-001 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Comments_ER14-503-001_20140307.pdf
March 11, 2014	IMM Comments re Response to Deficiency Notice Docket Nos. ER14-822-001 and EL14-20-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Answer_and_Motion_for_leave_to_Answer_EL14-20-000_20140311.pdf
March 24, 2014	IMM Comments re Response to Deficiency Notice Docket Nos. ER14-822-001 and EL14-20-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Comments_Docket_Nos._ER14-822-001_EL14-20-000_20140324.pdf
March 26, 2014	IMM Comments re Invenergy Waiver Docket No. ER14-1475-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Brief_EL08-14-010_20140407.pdf
March 26, 2014	Informational Filing re Waiver to Permit Make-Whole Payments Docket No. ER14-1144-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Make_Whole_Waiver_Report_ER14-1144_000_20140326.pdf
April 18, 2014	Analysis of the 2016/2017 RPM Base Residual Auction http://www.monitoringanalytics.com/reports/Reports/2013/Analysis_of_20162017_RPM_Base_Residual_Auction_20140418.pdf
April 30, 2014	IMM Answer to PJM re RPM Reform Docket No. ER14-1461-000,-001 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Answer_ER14-1461-000-001_20140430.pdf
May 9, 2014	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2015/2016, 2016/2017 and 2017/2018 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20140509.pdf
June 27, 2014	IMM Protest re CPV Maryland CfD Docket No. ER14-2106-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Protest_Docket_No_ER14-2106-000_20140627.pdf
June 27, 2014	IMM Protest re CPV New Jersey SOCA Docket No. ER14-2105-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Protest_Docket_No_ER14-2105-000_20140627.pdf
July 10, 2014	The 2017/2018 RPM Base Residual Auction: Sensitivity Analyses http://www.monitoringanalytics.com/reports/Reports/2014/IMM_20172018_RPM_BRA_Sensitivity_Analyses_20140710.pdf

Installed Capacity

On January 1, 2014, PJM installed capacity was 183,095.2 MW (Table 5-3).[27] Over the next six months, new generation, unit deactivations, facility reratings, plus import and export shifts resulted in PJM installed capacity of 184,006.9 MW on June 30, 2014, an increase of 911.7 MW or 0.5 percent over the January 1 level.[28 29] The 911.7 MW increase was the result of an increase in imports (2,258.0 MW), capacity modifications (334.0 MW), new or reactivated generation (280.5 MW), offset by deactivations (1,569.9 MW), derates (390.7 MW), and an increase in exports (0.2 MW).

At the beginning of the new Delivery Year on June 1, 2014, PJM installed capacity was 184,009.1 MW, an increase of 756.7 MW or 0.4 percent over the May 31 level.

Table 5-3 PJM installed capacity (By fuel source): January 1, May 31, June 1, and June 30, 2014

	1-Jan-14		31-May-14		1-Jun-14		30-Jun-14	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	75,544.6	41.3%	75,253.0	41.1%	74,785.5	40.6%	74,781.5	40.6%
Gas	53,395.0	29.2%	53,841.6	29.4%	55,041.7	29.9%	55,041.7	29.9%
Hydroelectric	8,106.7	4.4%	8,135.7	4.4%	8,463.8	4.6%	8,465.6	4.6%
Nuclear	33,076.7	18.1%	33,073.7	18.0%	32,891.0	17.9%	32,891.0	17.9%
Oil	11,314.2	6.2%	11,290.4	6.2%	11,155.7	6.1%	11,155.7	6.1%
Solar	84.2	0.0%	84.2	0.0%	94.7	0.1%	94.7	0.1%
Solid waste	701.4	0.4%	701.4	0.4%	780.0	0.4%	780.0	0.4%
Wind	872.4	0.5%	872.4	0.5%	796.7	0.4%	796.7	0.4%
Total	183,095.2	100.0%	183,252.4	100.0%	184,009.1	100.0%	184,006.9	100.0%

27 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.

28 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.

29 Wind resources accounted for 796.7 MW of installed capacity in PJM on June 30, 2014. 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.

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.[30] In the first six months of 2014, a Third Incremental Auction was held in February for the 2014/2015 Delivery Year, and a Base Residual Auction was held in May for the 2017/2018 Delivery Year.

Market Structure

Supply

Table 5-4 shows generation capacity changes since the implementation of the Reliability Pricing Model through the 2013/2014 Delivery Year. The 20,349.7 MW increase was the result of new Generation Capacity Resources (6,751.1 MW), reactivated Generation Capacity Resources (430.0 MW), uprates (4,620.9 MW), integration of external zones (18,109.0 MW), a net increase in capacity imports (4,363.6 MW), a net decrease in capacity exports (2,620.3 MW), offset by deactivations (13,854.4 MW) and derates (2,690.8 MW).

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

Table 5-4 Generation capacity changes: 2007/2008 through 2013/2014

	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)
2013/2014	185,567.9	264.7	20.9	397.9	0.0	2,228.9	21.6	4,027.7	421.9	(1,558.8)
2014/2015	184,009.1									
Total		6,751.1	430.0	4,620.9	18,109.0	4,363.6	(2,620.3)	13,854.4	2,690.8	20,349.7

Table 5-5 Capacity Market load obligations served: June 1, 2014

	Obligation (MW)							
	PJM EDCs	PJM EDC Generating Affiliates	PJM EDC Marketing Affiliates	Non-PJM EDC Generating Affiliates	Non-PJM EDC Marketing Affiliates	Non-EDC Generating Affiliates	Non-EDC Marketing Affiliates	Total
Obligation	69,805.8	40,021.6	16,381.3	4,961.4	18,080.0	1,780.2	26,583.1	177,613.4
Percent of total obligation	39.3%	22.5%	9.2%	2.8%	10.2%	1.0%	15.0%	100.0%

Demand

On June 1, 2014, PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 71.1 percent (Table 5-5), down slightly from 72.0 percent on June 1, 2013. The combined market share of LSEs not affiliated with any EDC and of non-PJM EDC affiliates was 28.9 percent, up slightly from 28.0 percent on June 1, 2013. Prior to the 2012/2013 Delivery Year, obligation was defined as cleared and make-whole MW in the Base Residual Auction and the Second Incremental Auction plus ILR forecast obligations. Effective with the 2012/2013 Delivery Year, obligation is defined as the sum of the unforced capacity obligations satisfied through all RPM Auctions for the Delivery Year.

Market Concentration

Auction Market Structure

As shown in Table 5-6, all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test in the 2017/2018 RPM Base Residual Auction.[31] 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.[32] [33] [34]

Table 5-6 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.

31 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.
32 See OATT Attachment DD § 6.5.
33 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.
34 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 5-6 RSI results: 2014/2015 through 2017/2018 RPM Auctions[35]

RPM Markets	$RSI_{1,\ 1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
2014/2015 Base Residual Auction				
RTO	0.76	0.58	93	93
MAAC	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	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	0.40	0.01	4	4
PSEG North	0.00	0.00	1	1
2014/2015 Third Incremental Auction				
RTO	0.56	0.27	53	53
MAAC	0.29	0.17	9	9
PSEG North	0.02	0.00	3	3
2015/2016 Base Residual Auction				
RTO	0.75	0.57	99	99
MAAC	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	0.15	0.09	5	5
PSEG	0.00	0.00	1	1
ATSI	0.00	0.00	1	1
2016/2017 Base Residual Auction				
RTO	0.78	0.59	110	110
MAAC	0.56	0.38	6	6
PSEG	0.00	0.00	1	1
ATSI	0.00	0.00	1	1
2017/2018 Base Residual Auction				
RTO	0.80	0.61	119	119
PSEG	0.00	0.00	1	1

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.[36] 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."[37] A reliability requirement and a Variable Resource Requirement (VRR) curve are established for each modeled LDA. Effective for the 2014/2015 through 2016/2017 Delivery Years, a Minimum Annual and a Minimum Extended Summer Resource Requirement are established for each modeled LDA. Effective for the 2017/2018 and subsequent Delivery Years, Sub-Annual and Limited Resource Constraints, replacing the Minimum Annual and a Minimum Extended Summer Resource Requirements, are established for each modeled LDA.[38]

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

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

36 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.

37 OATT Attachment DD § 5.10 (a) (ii).

38 146 FERC ¶ 61,052 (2014).

Figure 5-1 Map of PJM Locational Deliverability Areas

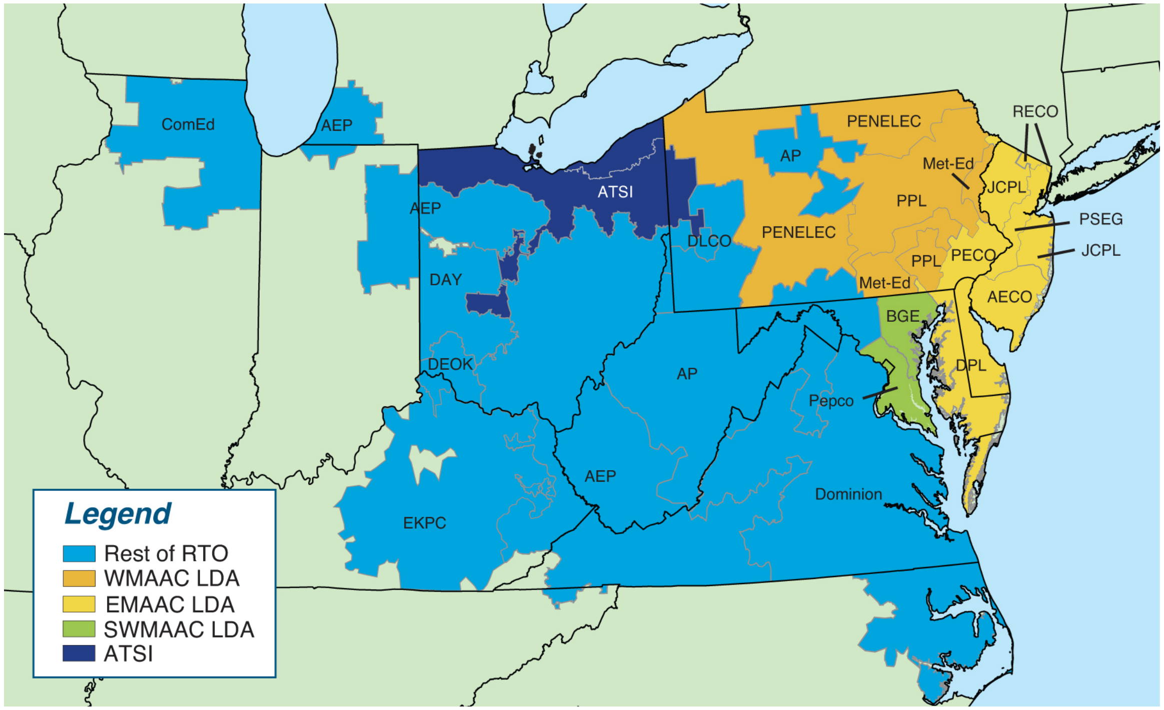


Figure 5-2 Map of PJM RPM EMAAC subzonal LDAs

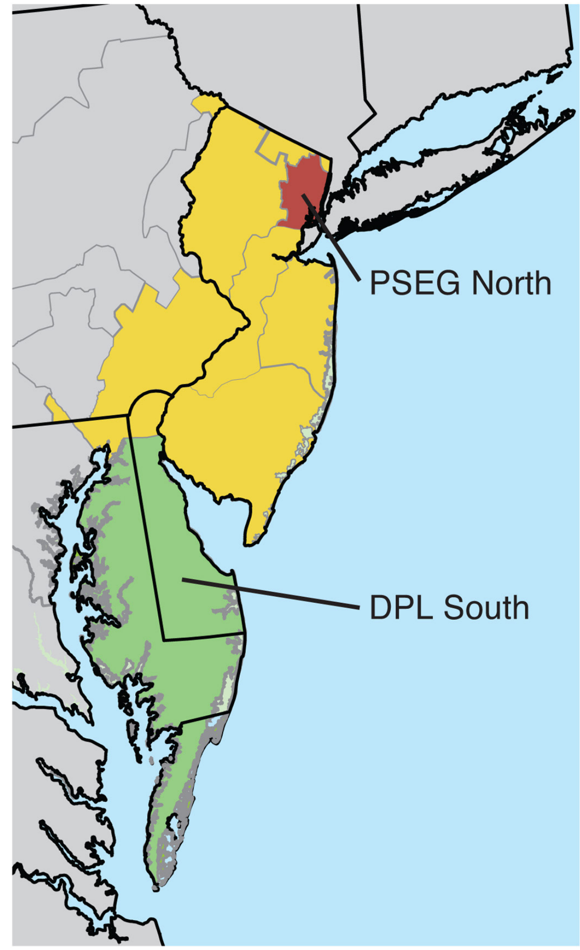
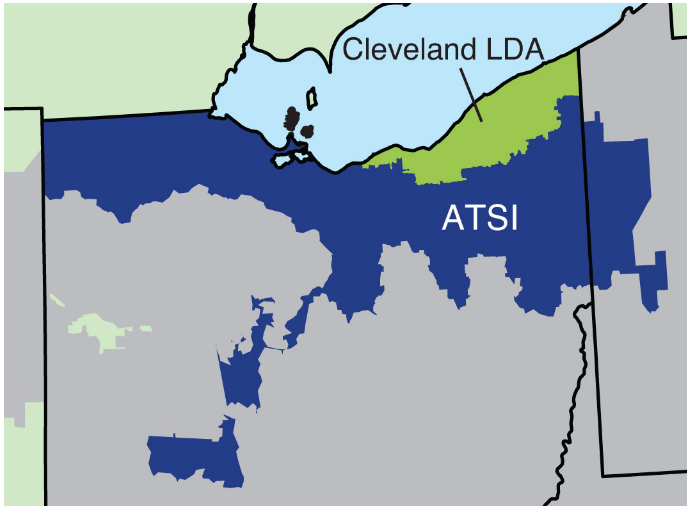


Figure 5-3 Map of PJM RPM ATSI subzonal LDA



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.[39]

The PJM market rules should not create inappropriate barriers to either the import or export of capacity. The market rules in other balancing authorities should also not create inappropriate barriers to the import or export of capacity. The PJM market rules should ensure that the definition of capacity is enforced including physical deliverability, recallability and the obligation to make competitive offers into the PJM Day-Ahead Energy Market. Physical deliverability can only be assured by requiring that all imports are required to have pseudo ties to PJM to ensure that they are full substitutes for internal capacity resources. Selling capacity into the PJM capacity market but making energy offers daily of $999 per MWh would not fulfill the requirements of a capacity resource to make a competitive offer, but would constitute economic withholding. This is one of the reasons that the rules governing the obligation to make a competitive offer in the Day-Ahead Energy Market should be clarified for both internal and external resources.

As shown in Table 5-7, a total of 4,525.5 MW of imports cleared in the 2017/2018 RPM Base Residual Auction. Of these cleared imports, 2,624.3 MW (58.0 percent) were from MISO.

Table 5-7 RPM imports: 2007/2008 through 2017/2018 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
2017/2018	2,624.3	2,624.3	2,320.4	1,901.2	4,944.7	4,525.5

Demand Resources

As shown in Table 5-8 and Table 5-10, capacity in the RPM load management programs was 9,493.6 MW for June 1, 2014 as a result of cleared capacity for Demand Resources and Energy Efficiency Resources in RPM Auctions for the 2014/2015 Delivery Year (16,020.7 MW) less replacement capacity (6,527.1 MW). Table 5-9 shows RPM commitments for DR and EE resources as the result of RPM Auctions prior to adjustments for replacement capacity transactions and certified ILR.

39 OATT Attachment DD § 5.6.6(b).

Table 5-8 RPM load management statistics by LDA: June 1, 2013 to June 1, 2017[40 41 42]

	UCAP (MW)												
	RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ATSI Cleveland	ComEd	BGE	PPL
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	14,943.0	7,452.4	2,976.9	2,268.4	220.9	999.5	468.4	920.0					
EE cleared	1,077.7	305.9	45.2	169.8	8.1	24.2	11.9	51.4					
DR net replacements	(6,731.8)	(3,778.7)	(1,651.1)	(1,010.7)	(156.0)	(550.4)	(231.1)	(428.9)					
EE net replacements	204.7	219.5	46.8	148.2	(6.8)	12.7	5.0	68.3					
RPM load management @ 01-Jun-14	9,493.6	4,199.1	1,417.8	1,575.7	66.2	486.0	254.2	610.8					
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			
DR cleared	10,975.0	4,277.3	1,535.6	1,399.6	86.3	388.4	151.5	608.4	1,020.2	290.1	1,478.1	791.2	686.4
EE cleared	1,338.9	368.5	79.3	227.9	0.8	17.6	3.4	104.2	142.0	35.7	583.3	123.7	35.6
DR net replacements	0.0	0.0	0.0	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	0.0	0.0	0.0
RPM load management @ 01-Jun-17	12,313.9	4,645.8	1,614.9	1,627.5	87.1	406.0	154.9	712.6	1,162.2	325.8	2,061.4	914.9	722.0
DR cleared	4,163.4												
EE cleared	173.5												
DR net replacements	(3,413.0)												
EE net replacements	79.7												
	1,003.6												

40 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 (EE) resource type is eligible to be offered in RPM Auctions.

41 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.

42 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 include transactions associated with RTP Controls, Inc. which was declared in collateral default on March 9, 2012.

Table 5-9 RPM load management cleared capacity and ILR: 2007/2008 through 2017/2018[43 44]

	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	14,337.6	14,943.0	1,035.4	1,077.7	0.0	0.0
2015/2016	14,325.7	14,922.1	970.2	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
2017/2018	10,551.0	10,975.0	1,288.0	1,338.9	0.0	0.0

Table 5-10 RPM load management statistics: June 1, 2007 to June 1, 2017[45 46]

	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	15,373.0	16,020.7	(6,458.4)	(6,731.8)	196.4	204.7	9,111.0	9,493.6
01-Jun-15	15,295.9	15,932.0	0.0	0.0	0.0	0.0	15,295.9	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
01-Jun-17	11,839.0	12,313.9	0.0	0.0	0.0	0.0	11,839.0	12,313.9

43 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.

44 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.

45 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.

46 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 included transactions 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.[47 48 49]

47 See OATT Attachment DD § 6.5.

48 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.

49 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 5-11 ACR statistics: 2017/2018 RPM Auctions

	2017/2018 Base Residual Auction	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	369	30.7%
ACR data input (APIR)	122	10.1%
ACR data input (non-APIR)	4	0.3%
Opportunity cost input	5	0.4%
Default ACR and opportunity cost	0	0.0%
Offer cap of 1.1 times BRA clearing price elected	NA	NA
Uncapped planned uprate and default ACR	31	2.6%
Uncapped planned uprate and opportunity cost	0	0.0%
Uncapped planned uprate and price taker	6	0.5%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA
Uncapped planned generation resources	28	2.3%
Price takers	637	53.0%
Total Generation Capacity Resources offered	1,202	100.0%

2017/2018 RPM Base Residual Auction

As shown in Table 5-11, 1,202 generation resources submitted offers in the 2017/2018 RPM Base Residual Auction. Unit-specific offer caps were calculated for 131 generation resources (10.9 percent of all generation resources), of which 122 generation resources included an APIR component. The MMU calculated offer caps for 531 generation resources (44.2 percent), of which 400 were based on the technology specific default (proxy) ACR values. Of the 1,202 generation resources, 28 Planned Generation Capacity Resources had uncapped offers (2.3 percent), while the remaining 643 generation resources were price takers (53.5 percent). Market power mitigation was applied to the sell offers for 39 generation resource.

Market Performance[50]

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 5-12 shows RPM clearing prices for all RPM Auctions held through the first six months of 2014.

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 six months of 2014.

Table 5-13 shows RPM revenue by resource type for all RPM Auctions held through the first six months of 2014 with $2.1 billion for new/repower/reactivated generation resources based on the unforced MW cleared and the resource clearing prices. 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.

Table 5-14 shows RPM revenue by calendar year for all RPM Auctions held through the first six months of 2014.

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

Table 5-12 Capacity prices: 2007/2008 through 2017/2018 RPM Auctions

		RPM Clearing Price ($ per MW-day)										
	Product Type	RTO	MAAC	APS	PPL	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI
2007/2008 BRA		$40.80	$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	$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	$10.00	$223.85	$10.00	$10.00	$10.00	$223.85	
2009/2010 BRA		$102.04	$191.32	$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	$86.00	
2010/2011 BRA		$174.29	$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	$50.00	
2011/2012 BRA		$110.00	$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	$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	$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	$5.00
2012/2013 BRA		$16.46	$133.37	$16.46	$133.37	$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	$20.46
2012/2013 First Incremental Auction		$16.46	$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	$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	$2.51
2013/2014 BRA		$27.73	$226.15	$27.73	$226.15	$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	$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	$10.00	$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	$30.00	$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	$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	$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	$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	$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	$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	$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	$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	$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	$56.94	$310.00	$56.94	$25.00
2014/2015 Third Incremental Auction	Limited	$25.51	$132.20	$25.51	$132.20	$132.20	$132.20	$132.20	$132.20	$256.76	$132.20	$25.51
2014/2015 Third Incremental Auction	Extended Summer	$25.51	$132.20	$25.51	$132.20	$132.20	$132.20	$132.20	$132.20	$256.76	$132.20	$25.51
2014/2015 Third Incremental Auction	Annual	$25.51	$132.20	$25.51	$132.20	$132.20	$132.20	$132.20	$132.20	$256.76	$132.20	$25.51
2015/2016 BRA	Limited	$118.54	$150.00	$118.54	$150.00	$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	$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	$167.46	$357.00
2015/2016 First Incremental Auction	Limited	$43.00	$111.00	$43.00	$111.00	$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	$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	$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	$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	$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	$119.13	$219.00	$219.00	$119.13	$114.23
2017/2018 BRA	Limited	$106.02	$106.02	$106.02	$40.00	$106.02	$106.02	$106.02	$201.02	$201.02	$106.02	$106.02
2017/2018 BRA	Extended Summer	$120.00	$120.00	$120.00	$53.98	$120.00	$120.00	$120.00	$215.00	$215.00	$120.00	$120.00
2017/2018 BRA	Annual	$120.00	$120.00	$120.00	$120.00	$120.00	$120.00	$120.00	$215.00	$215.00	$120.00	$120.00

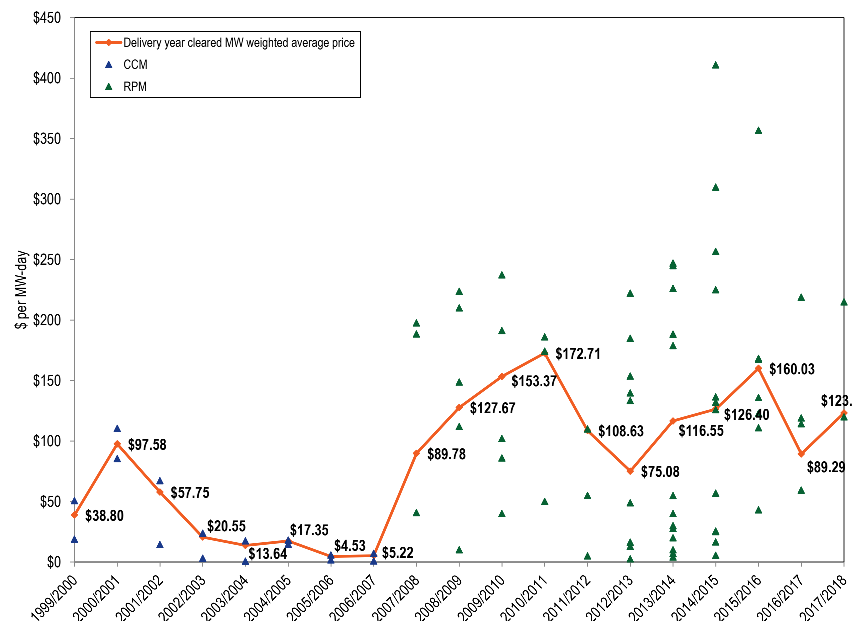
Table 5-13 RPM revenue by type: 2007/2008 through 2017/2018[51] [52]

				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	$1,743,995,977	$12,950,135	$1,847,875,198	$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	$681,315,139	$42,308,549	$135,573,409	$1,945,606,114	$57,078,818	$2,001,310,409	$205,555,569	$333,941,614	$6,649,774	$1,464,950,862	$0	$484,752,670	$4,106,697	$0	$3,836,582	$34,281,137	$1,709,533	$1,524,551	$32,766,219	$7,437,267,646
2015/2016	$882,512,351	$55,664,349	$190,102,852	$2,778,432,087	$63,163,731	$2,476,236,291	$529,577,871	$385,193,684	$14,880,302	$1,849,263,911	$0	$566,555,231	$5,243,967	$0	$4,526,101	$35,413,724	$4,258,208	$1,829,269	$41,406,297	$9,884,260,226
2016/2017	$437,607,477	$35,346,456	$157,012,514	$1,258,618,638	$42,487,007	$1,461,721,819	$498,909,311	$218,627,999	$10,031,353	$1,002,422,494	$0	$327,077,318	$4,026,475	$0	$4,868,047	$28,253,285	$3,780,862	$1,144,873	$20,886,259	$5,512,822,187
2017/2018	$476,896,058	$59,254,100	$189,649,620	$1,839,412,938	$56,002,680	$2,077,372,315	$860,951,050	$312,755,908	$15,124,140	$1,155,829,440	$0	$386,202,120	$5,479,380	$0	$6,440,243	$30,737,198	$5,752,583	$1,292,100	$33,077,760	$7,512,229,630

Table 5-14 RPM revenue by calendar year: 2007 through 2018[53]

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	$122.32	160,668.7	365	$7,173,539,072
2015	$146.12	166,057.4	365	$8,856,286,267
2016	$118.67	168,936.9	366	$7,337,483,492
2017	$109.17	167,776.4	365	$6,685,249,469
2018	$123.19	167,068.9	151	$3,107,799,107

Figure 5-4 History of PJM capacity prices: 1999/2000 through 2017/2018[54]



51 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.
52 The results for the ATSI Integration Auctions are not included in this table.
53 The results for the ATSI Integration Auctions are not included in this table.

54 1999/2000-2006/2007 capacity prices are CCM combined market, weighted average prices. The 2007/2008-2017/2018 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 and subsequent Delivery Years, only the prices for Annual Resources are plotted.

Figure 5-5 Map of RPM capacity prices: 2014/2015 through 2017/2018

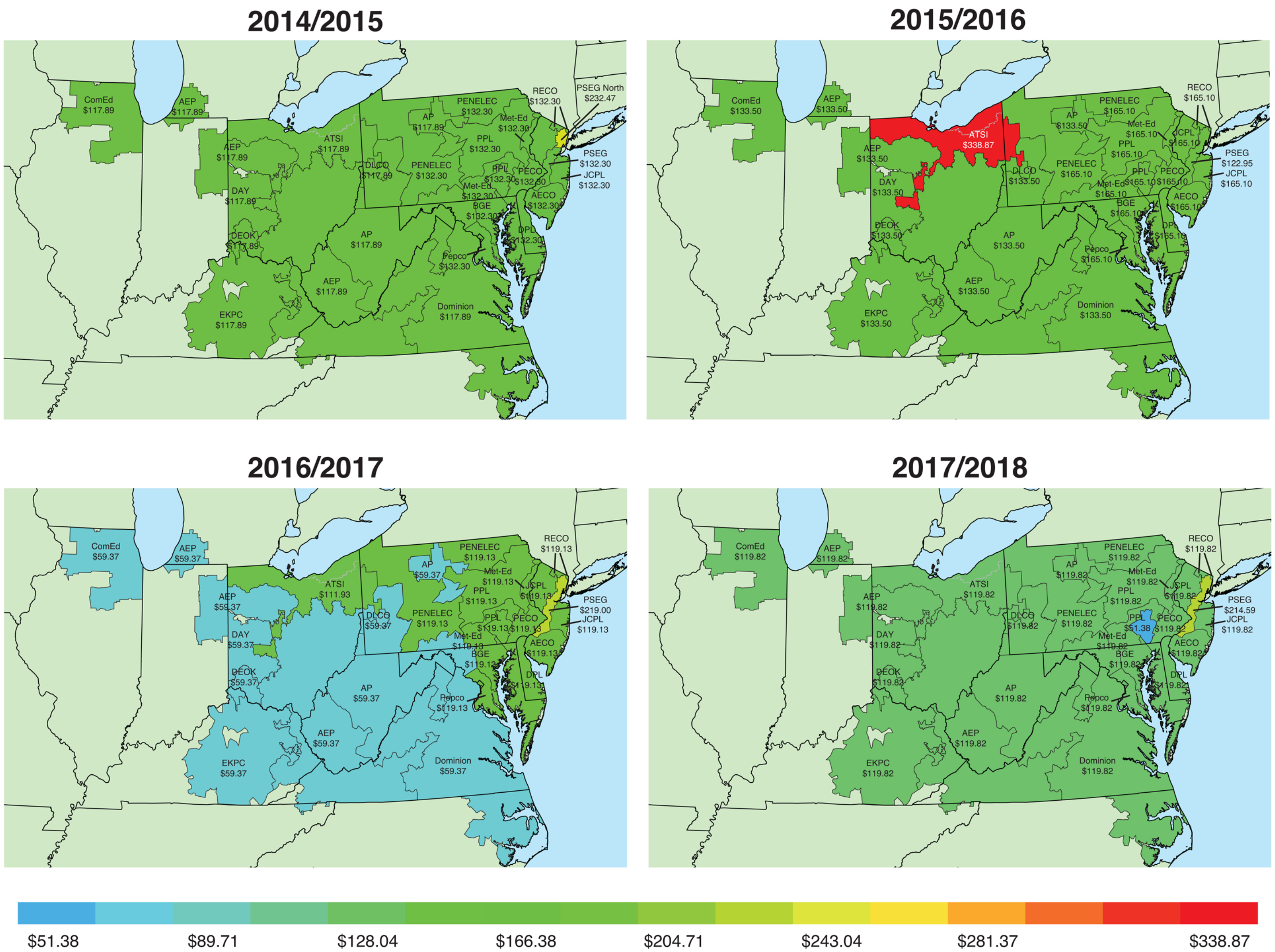


Table 5-15 shows the RPM annual charges to load. For the 2014/2015 Delivery Year, RPM annual charges to load total approximately $7.3 billion.

Table 5-15 RPM cost to load: 2013/2014 through 2017/2018 RPM Auctions[55 56 57]

	Net Load Price ($ per MW-day)	UCAP Obligation (MW)	Annual Charges
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	$128.38	80,953.8	$3,793,425,139
Rest of MAAC	$137.55	30,041.3	$1,508,211,854
Rest of EMAAC	$137.54	19,983.0	$1,003,188,500
DPL	$145.38	4,551.5	$241,523,752
PSEG	$171.59	11,563.7	$724,229,563
Total		147,093.3	$7,270,578,809
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
2017/2018			
Rest of RTO	$119.81	102,465.9	$4,480,913,201
Rest of MAAC	$119.92	48,299.9	$2,114,192,959
PSEG	$175.21	11,853.1	$758,017,691
PPL	$118.18	8,510.0	$367,082,164
Total		171,128.9	$7,720,206,015

55 The RPM annual charges are calculated using the rounded, net load prices as posted in the PJM Base Residual Auction results.
56 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.
57 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 2015/2016, 2016/2017, and 2017/2018 Net Load Prices are not finalized. The 2015/2016, 2016/2017, and 2017/2018 obligation MW are not finalized.

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).[58]

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 six months of 2014, nuclear units had a capacity factor of 92.3 percent, compared to 92.6 percent in the first six months of 2013. Combined cycle units ran more often, increasing from a capacity factor of 49.3 percent in the first six months of 2013 to 49.4 in the first six months of 2014. The capacity factor for steam units, which are primarily coal fired, increased from 48.7 percent in the first six months of 2013 to 53.3 percent in the first six months of 2014.

58 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.

Table 5-16 PJM capacity factor (By unit type (GWh)): January through June of 2013 and 2014[59 60]

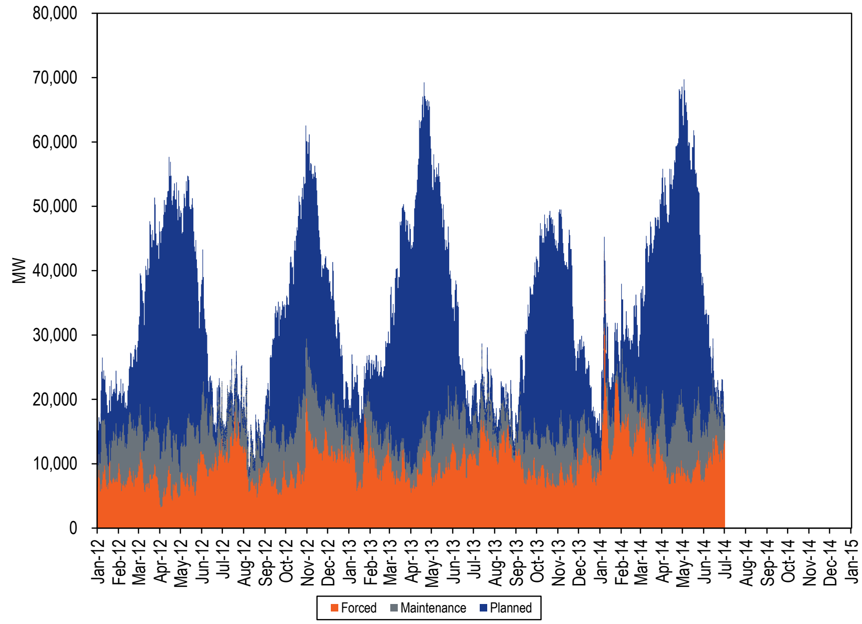
	2013 (Jan - Jun)		2014 (Jan - Jun)	
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor
Combined Cycle	56,914.7	49.3%	57,485.1	49.4%
Combustion Turbine	2,431.6	1.9%	4,863.0	3.7%
Diesel	135.5	9.1%	149.7	10.2%
Diesel (Landfill gas)	625.7	54.0%	683.7	57.4%
Fuel Cell	32.0	83.6%	109.3	83.9%
Nuclear	135,858.8	92.6%	134,954.5	92.3%
Pumped Storage Hydro	3,206.1	13.4%	3,463.2	14.3%
Run of River Hydro	4,257.0	40.6%	4,740.6	41.9%
Solar	175.9	16.1%	197.7	15.8%
Steam	173,376.9	48.7%	186,606.0	53.3%
Wind	8,561.5	31.6%	8,678.0	31.5%
Total	385,575.7	47.4%	401,930.7	49.4%

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 the seasonal variation in outages can be seen in the monthly generator performance metrics in "Performance By Month."

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.

Figure 5-6 PJM outages (MW): January 2012 through June 2014



The PJM aggregate EAF for the first six months of 2014 was 80.3 percent, a decrease from 81.8 percent for the first six months of 2013. The PJM aggregate EAF, EFOF, EPOF, and EMOF are shown in Figure 5-7. Metrics by unit type are shown in Table 5-17 through Table 5-20.

59 The EKPC Transmission Zone was integrated on June 1, 2013 and is not included in the numbers for the first five months of 2013.
60 The capacity factor for each unit type was calculated based on units that are capacity resources and solar and wind units that are not capacity resources. As a result of not including all units, the total annual generation is slightly lower than the totals reported in the *2014 Quarterly State of the Market Report for PJM: January through June*, Section 3, "Energy Market," Energy Production by Fuel Source.

Table 5-17 EAF by unit type: January through June, 2007 through 2014

	2007 (Jan - Jun)	2008 (Jan - Jun)	2009 (Jan - Jun)	2010 (Jan - Jun)	2011 (Jan - Jun)	2012 (Jan - Jun)	2013 (Jan - Jun)	2014 (Jan - Jun)
Combined Cycle	88.9%	89.2%	86.3%	83.9%	83.2%	86.0%	82.4%	81.8%
Combustion Turbine	89.1%	89.4%	92.5%	93.3%	93.0%	93.1%	89.6%	85.4%
Diesel	87.6%	87.5%	91.4%	94.4%	95.2%	94.1%	93.8%	82.4%
Hydroelectric	90.7%	89.6%	84.6%	86.5%	87.0%	88.9%	90.2%	82.2%
Nuclear	93.9%	91.4%	89.6%	92.2%	88.6%	89.8%	90.8%	89.6%
Steam	79.2%	79.5%	79.2%	78.3%	75.9%	76.4%	74.6%	74.1%
Total	85.2%	84.8%	84.3%	84.3%	82.2%	83.2%	81.8%	80.3%

Table 5-18 EMOF by unit type: January through June, 2007 through 2014

	2007 (Jan - Jun)	2008 (Jan - Jun)	2009 (Jan - Jun)	2010 (Jan - Jun)	2011 (Jan - Jun)	2012 (Jan - Jun)	2013 (Jan - Jun)	2014 (Jan - Jun)
Combined Cycle	2.1%	1.6%	3.1%	4.3%	2.9%	2.2%	3.2%	2.4%
Combustion Turbine	2.6%	2.5%	2.4%	1.8%	1.8%	1.8%	1.7%	1.9%
Diesel	2.4%	1.4%	1.5%	1.1%	2.7%	1.9%	1.7%	2.8%
Hydroelectric	2.1%	2.3%	3.0%	2.2%	1.7%	1.5%	2.1%	4.0%
Nuclear	0.3%	0.5%	0.7%	0.6%	2.0%	0.8%	0.6%	0.7%
Steam	2.4%	2.6%	3.5%	3.4%	3.9%	6.2%	4.3%	5.5%
Total	2.0%	2.1%	2.7%	2.7%	3.0%	3.8%	2.9%	3.5%

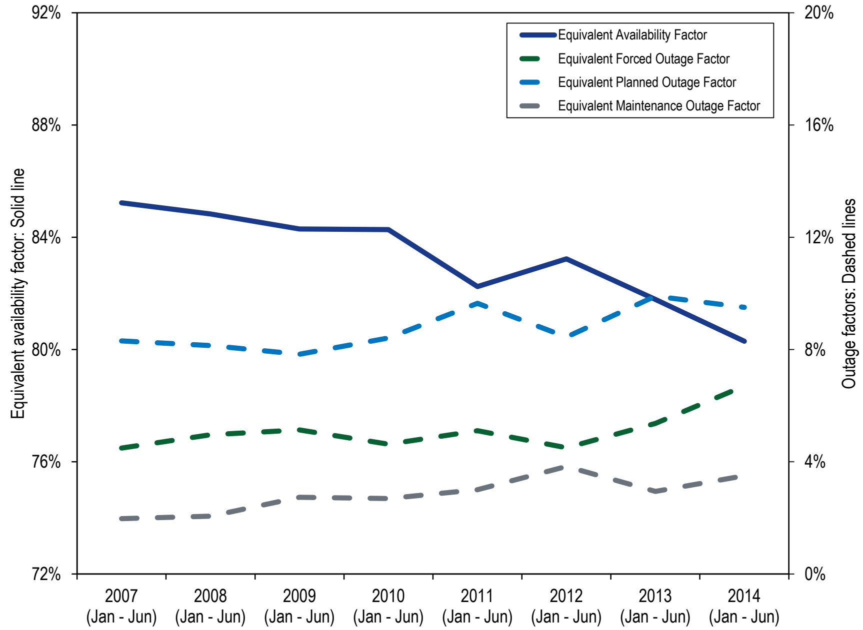
Table 5-19 EPOF by unit type: January through June, 2007 through 2014

	2007 (Jan - Jun)	2008 (Jan - Jun)	2009 (Jan - Jun)	2010 (Jan - Jun)	2011 (Jan - Jun)	2012 (Jan - Jun)	2013 (Jan - Jun)	2014 (Jan - Jun)
Combined Cycle	7.3%	7.6%	7.5%	9.0%	11.5%	9.6%	11.3%	12.9%
Combustion Turbine	3.1%	5.1%	3.6%	3.0%	3.8%	3.0%	3.7%	4.5%
Diesel	0.8%	1.8%	0.4%	0.7%	0.0%	0.1%	0.4%	0.8%
Hydroelectric	5.7%	6.7%	10.3%	10.6%	9.9%	5.8%	7.3%	12.0%
Nuclear	4.7%	7.1%	5.7%	6.0%	7.7%	8.3%	7.2%	7.9%
Steam	11.9%	9.8%	9.9%	10.8%	11.8%	10.2%	13.0%	10.8%
Total	8.3%	8.1%	7.8%	8.4%	9.6%	8.4%	9.9%	9.5%

Table 5-20 EFOF by unit type: January through June, 2007 through 2014

	2007 (Jan - Jun)	2008 (Jan - Jun)	2009 (Jan - Jun)	2010 (Jan - Jun)	2011 (Jan - Jun)	2012 (Jan - Jun)	2013 (Jan - Jun)	2014 (Jan - Jun)
Combined Cycle	1.7%	1.6%	3.1%	2.7%	2.4%	2.2%	3.1%	3.0%
Combustion Turbine	5.3%	3.0%	1.6%	1.9%	1.3%	2.1%	5.1%	8.1%
Diesel	9.2%	9.3%	6.7%	3.8%	2.1%	3.8%	4.1%	13.9%
Hydroelectric	1.5%	1.4%	2.1%	0.7%	1.4%	3.9%	0.5%	1.8%
Nuclear	1.1%	1.0%	4.0%	1.2%	1.8%	1.0%	1.4%	1.7%
Steam	6.5%	8.2%	7.4%	7.5%	8.4%	7.2%	8.1%	9.6%
Total	4.5%	5.0%	5.1%	4.6%	5.1%	4.5%	5.4%	6.7%

Figure 5-7 PJM equivalent outage and availability factors: January through June, 2007 to 2014



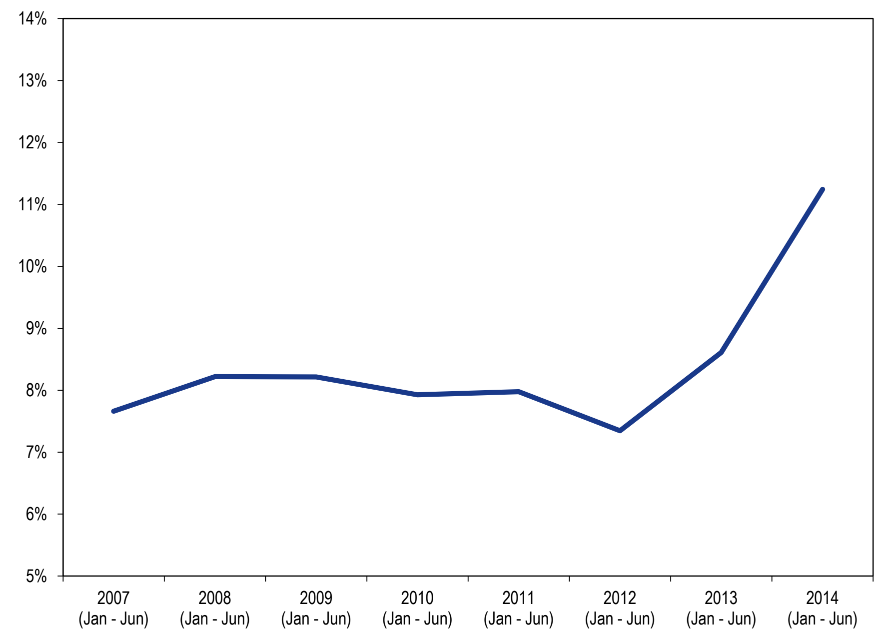
Generator Forced Outage Rates

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.[61] The EFORd metric includes all forced outages, regardless of the reason for those outages.

The average PJM EFORd for the first six months of 2014 was 11.2 percent, an increase from the 8.6 percent average PJM EFORd for the first six months of 2013. 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): January through June, 2007 through 2014



61 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 5-21 shows the class average EFORd by unit type. Outage rates increased for all unit types and CT and DS units had a particularly high increase in outage rates in the first six months of 2014.

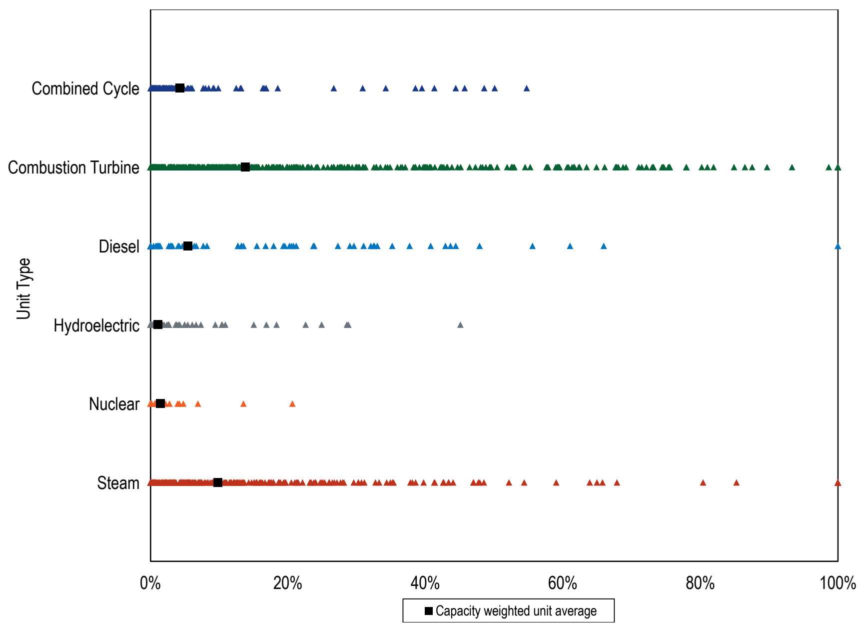
Table 5-21 PJM EFORd data for different unit types: January through June, 2007 through 2014

	2007 (Jan - Jun)	2008 (Jan - Jun)	2009 (Jan - Jun)	2010 (Jan - Jun)	2011 (Jan - Jun)	2012 (Jan - Jun)	2013 (Jan - Jun)	2014 (Jan - Jun)
Combined Cycle	3.8%	3.4%	5.2%	4.3%	3.5%	2.9%	3.9%	5.2%
Combustion Turbine	16.7%	14.2%	10.3%	13.8%	8.4%	8.8%	14.1%	21.8%
Diesel	10.7%	10.1%	8.5%	5.5%	6.1%	5.1%	4.3%	15.1%
Hydroelectric	2.2%	2.1%	2.5%	1.1%	1.9%	5.5%	0.7%	3.0%
Nuclear	1.2%	1.1%	4.0%	1.5%	2.1%	1.2%	1.6%	2.0%
Steam	8.7%	10.7%	10.3%	9.8%	11.5%	10.4%	11.4%	13.6%
Total	7.7%	8.2%	8.2%	7.9%	8.0%	7.3%	8.6%	11.2%

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 in EFORd, while nuclear units had the lowest variance in EFORd values in the first six months of 2014.

Figure 5-9 PJM distribution of EFORd data by unit type: January through June 2014



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

There are two 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's ICAP, rather than one minus EFORd.

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 in PJM's Capacity Market. Thus, the PJM capacity market rules, as currently written, create 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.

In 2006, NERC created specifications for certain types of outages deemed to be Outside Management Control (OMC).[62] 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.[63] 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 NERC.

Nothing in NERC's classification of outages requires that PJM exclude OMC outages from the forced outage rate metrics used in the Capacity Market.[64] That choice was made by PJM and can be modified without violating any NERC requirements.[65] It is possible to have an OMC outage under the NERC definition, which PJM does not define as an OMC outage 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.

62 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>.

63 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>.

64 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.

65 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.

At present, PJM does not have a clear, documented, public set of criteria for designating outages as OMC, although PJM's actual practice appears to be improving.

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 5-22 shows OMC forced outages by cause code, as classified by PJM. OMC forced outages accounted for 12.9 percent of all forced outages in the first six months of 2014. The second-largest contributor to OMC outages, lack of fuel, was the cause of 22.5 percent of OMC outages and 2.9 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 several units that have been on outage since the 2012 hurricane.

An outage is an outage, regardless of the cause. It is inappropriate that units on outage do not have to reflect that outage in their outage statistics, which affect their performance incentives and the level of unforced capacity and therefore capacity sold. No outages should be treated as OMC because when a unit is not available it is not available, regardless of the reason, and the data and payments to units should reflect that fact.

Table 5-22 OMC Outages: January through June 2014

OMC Cause Code	Percent of OMC Forced Outages	Percent of all Forced Outages
Hurricane	40.2%	5.2%
Lack of fuel	22.5%	2.9%
Flood	17.4%	2.2%
Lightning	6.5%	0.8%
Transmission system problems other than catastrophes	4.7%	0.6%
Other switchyard equipment	3.7%	0.5%
Switchyard circuit breakers	1.1%	0.1%
Transmission equipment beyond the 1st substation	0.8%	0.1%
Transmission line	0.7%	0.1%
Other miscellaneous external problems	0.6%	0.1%
Storms (ice)	0.4%	0.1%
Switchyard transformers and associated cooling systems	0.4%	0.0%
Lack of water (hydro)	0.3%	0.0%
Transmission equipment at the 1st substation	0.2%	0.0%
High sulfur content	0.2%	0.0%
Switchyard system protection devices	0.1%	0.0%
Frozen coal	0.1%	0.0%
Other fuel quality problems	0.1%	0.0%
Tornado	0.0%	0.0%
Wet coal	0.0%	0.0%
Miscellaneous regulatory	0.0%	0.0%
Total	100.0%	12.9%

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, including contracts with intermediaries, 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 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.[66]

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.

Performance Incentives

There are a number of performance incentives in the capacity market, but they fall short of the incentives that a unit would face if it earned all its revenue in an energy market.[67] The most basic incentive is that associated with the reduction of payments for a failure to perform. In any market, sellers are not paid when they do not provide a product. That is only partly true in the PJM Capacity Market. In addition to the exclusion of OMC outages, which reduces forced outage rates resulting in payments to capacity resources not consistent with actual forced outage rates, other performance incentives are not designed to ensure that capacity resources are paid when they perform and not paid when they do not perform.

In concept, units do not receive RPM revenues to the extent that they do not perform during defined peak hours, but there are significant limitations on this incentive in the current rules.

The maximum level of RPM revenues at risk are based on the difference between a unit's actual Peak Period Capacity Available (PCAP) and the unit's expected Target Unforced Capacity (TCAP). PCAP is based on EFORp while TCAP is based on XEFORd- 5. PCAP is the resource position, while TCAP is the resource commitment. In other words, if the forced outage rate during the peak hours (EFORp) is greater than the forced outage rate calculated over a five year period (XEFORd-5), the unit owner may have a capacity shortfall of up to 50 percent of the unit's capacity commitment in the first year.

(PCAP) Peak Period Capacity = ICAP * (1 - EFORp)

(TCAP) Target Unforced Capacity = ICAP * (1 – XEFORd-5)

Peak Period Capacity Shortfall = TCAP – PCAP

66 For more on this issue, see the MMU'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).

67 This section focuses on capacity resources that are not in FRR plans. The FRR incentives differ from the incentives discussed here.

The Peak-Hour Period Availability Charge is equal to the seller's weighted average resource clearing price for the delivery year for the LDA.[68]

The peak hour availability charge understates the appropriate revenues at risk for underperformance because it is based on EFORp and because it is compared to a five year XEFORd. Both outage measures exclude OMC outages. The use of a five year average XEFORd measure is questionable as the measure of expected performance during the delivery year because it covers a period which is so long that it is unlikely to be representative of the current outage performance of the unit. The UCAP sold during a delivery year is a function of ICAP and the final Effective EFORd,[69] which is defined to be the XEFORd calculated for the 12 months ending in September in the year prior to the Delivery Year.

This maximum level of RPM revenues at risk is reduced by several additional factors including the ability to net any shortfalls against over performance across all units owned by the same participant within an LDA and the ability to use performance by resources that were offered into RPM but did not clear as an offset.[70]

Excess Available Capacity (EAC) may also be used to offset Peak Hour Availability shortfalls. EAC is capacity which was offered into RPM Auctions, did not clear but was offered into all PJM markets consistent with the obligations of a capacity resource. EAC must be part of a participant's total portfolio, but does not have to be in the same LDA as the shortfall being offset, unlike the netting provision.[71]

There is a separate exception to the performance related incentives related to lack of gas during the winter period. Single-fuel, natural gas-fired units do not face the Peak-Hour Period Availability Charge during the winter if the capacity shortfall was due to nonavailability of gas to supply the unit.[72] The result is an exception, analogous to the lack of fuel exception, except much broader, which appears to have no logical basis.

68 PJM. OATT Attachment DD § 10 (j).
69 PJM. "Manual 18: PJM Capacity Market," Revision 15 (June 28, 2012), p. 159
70 PJM. "Manual 18: PJM Capacity Market," Revision 15 (June 28, 2012), Section 8.4.5.
71 PJM. "Manual 18: PJM Capacity Market," Revision 15 (June 28, 2012), Section 8.4.5.1.
72 PJM. OATT Attachment DD § 7.10 (e).

There is a separate exception to the performance related incentives related to a unit that runs less than 50 hours during the RPM peak period. If a unit runs for less than 50 peak period service hours, then the EFORp used in the calculation of the peak hour availability charges is based on PCAP calculated using the lower of the delivery year XEFORd or the EFORp.[73]

There is a separate exception for wind and solar capacity resources which are exempt from this performance incentive.[74]

The peak hour availability charge does not apply if the unit unavailability resulted in another performance related charge or penalty.[75]

Under the peak hour availability charge, the maximum exposure to loss of capacity market revenues is 50 percent in the first year of higher than 50 percent EFORp. That percent increases to 75 percent in year two of sub 50 percent performance and to 100 percent in year three, but returns to a maximum of 50 percent after three years of better performance.

This limitation on maximum exposure is in addition to limitations that result from the way in which PJM applies the OMC rules in the calculation of EFORp and XEFORd, is in addition to the exclusion for gas availability in the winter, which is over and above the OMC exclusion, and is in addition to the case where a unit has less than 50 service hours in a delivery year and can use the lower of the delivery year XEFORd or EFORp.

Not all unit types are subject to RPM performance incentives. In addition to the exceptions which apply to conventional generation as a result of EFORp and XEFORd calculations, wind, solar and hydro generation capacity resources are exempt from key performance incentives. Wind and solar generation capacity resources are not subject to peak hour availability incentives, to summer or winter capability testing or to peak season maintenance compliance rules. Hydro generation capacity resources are not subject to peak season maintenance compliance rules.[76]

73 PJM. OATT Attachment DD § 7.10 (e).
74 PJM. OATT Attachment DD § 7.10 (e).
75 PJM. OATT Attachment DD § 7.10 (e).
76 PJM. "Manual 18: PJM Capacity Market," Revision 15 (June 28, 2012) p. 98.

Given that all generation is counted on for comparable contributions to system reliability, the MMU recommends that all generation types face the same performance incentives. The MMU recommends that the performance incentives in the RPM Capacity Market design be strengthened.

The MMU recommends that generation capacity resources be paid on the basis of whether they produce energy when called upon during any of the hours defined as critical. All revenues should be at risk under the peak hour availability charge.

Given that all generation is counted on for comparable contributions to system reliability, the MMU recommends that all generation types face the same performance incentives.

The MMU recommends elimination of the exception related to lack of gas during the winter period for single-fuel, natural gas-fired units.

The MMU recommends elimination of the exception related to a unit that runs less than 50 hours during the RPM peak period.

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.[77] On a systemwide basis, the resultant lost equivalent availability from the forced outages is equal to the equivalent forced outage factor.[78]

PJM EFOF was 6.7 percent in the first six months of 2014. This means there was 6.7 percent lost availability because of forced outages. Table 5-23 shows that forced outages for boiler tube leaks, at 19.5 percent of the systemwide EFOF, were the largest single contributor to EFOF.

77 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.
78 EFOF incorporates all outages regardless of their designation as OMC.

Table 5-23 Contribution to EFOF by unit type by cause: January through June 2014

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	System
Boiler Tube Leaks	2.9%	0.0%	0.0%	0.0%	0.0%	26.7%	19.5%
Catastrophe	12.2%	37.9%	5.3%	6.8%	6.3%	2.7%	8.3%
Economic	3.0%	18.3%	2.5%	1.9%	0.0%	4.7%	6.1%
Electrical	2.7%	6.9%	5.2%	22.3%	12.4%	4.2%	5.1%
Boiler Air and Gas Systems	0.0%	0.0%	0.0%	0.0%	0.0%	6.8%	4.9%
Feedwater System	2.1%	0.0%	0.0%	0.0%	6.2%	4.8%	3.9%
High Pressure Turbine	8.2%	0.0%	0.0%	0.0%	0.0%	3.3%	3.0%
Boiler Fuel Supply from Bunkers to Boiler	0.7%	0.0%	0.0%	0.0%	0.0%	4.0%	2.9%
Boiler Piping System	4.7%	0.0%	0.0%	0.0%	0.0%	3.2%	2.7%
Miscellaneous (Steam Turbine)	2.8%	0.0%	0.0%	0.0%	2.4%	3.1%	2.6%
Reserve Shutdown	1.6%	5.3%	20.1%	6.7%	0.8%	1.8%	2.3%
Miscellaneous (Generator)	4.0%	2.0%	20.7%	23.6%	0.0%	1.3%	2.0%
Controls	3.2%	2.0%	0.3%	0.3%	6.1%	1.4%	1.8%
Fuel, Ignition and Combustion Systems	14.7%	4.2%	0.0%	0.0%	0.0%	0.0%	1.7%
Valves	2.2%	0.0%	0.0%	0.0%	2.3%	1.9%	1.6%
Condensing System	1.1%	0.0%	0.0%	0.0%	1.9%	1.8%	1.4%
Fuel Quality	0.0%	0.2%	2.1%	0.0%	0.0%	1.9%	1.4%
Circulating Water Systems	0.9%	0.0%	0.0%	0.0%	5.1%	1.5%	1.4%
Miscellaneous (Boiler)	0.1%	0.0%	0.0%	0.0%	0.0%	1.9%	1.4%
All Other Causes	32.9%	23.3%	43.7%	38.5%	56.5%	23.2%	25.9%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Table 5-24 shows the categories which are included in the economic category.[79] Lack of fuel that is considered outside management control accounted for 47.6 percent of all economic reasons.

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."[80] 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.

Table 5-24 Contributions to Economic Outages: January through June 2014

	Contribution to Economic Reasons
Lack of fuel (Non-OMC)	48.0%
Lack of fuel (OMC)	47.6%
Other economic problems	1.8%
Fuel conservation	1.6%
Lack of water (Hydro)	0.6%
Problems with Primary Fuel for Units with Secondary Fuel Operation	0.3%
Ground water or other water supply problems	0.0%
Total	100.0%

79 The definitions of these outages are defined by NERC GADS.
80 The definitions of these outages are defined by NERC GADS.

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.[81] 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 combustion turbines and nuclear units, EFORp is lower than XEFORd, suggesting that units elect to take non-OMC 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 but it does not directly address the question of the incentive effect of omitting OMC outages from the EFORP metric.

Table 5-25 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 combustion turbine units.

Table 5-25 PJM EFORd, XEFORd and EFORp data by unit type: January through June 2014[82]

	EFORd	XEFORd	EFORp	Difference EFORd and XEFORd	Difference EFORd and EFORp
Combined Cycle	5.2%	4.9%	2.8%	0.2%	2.4%
Combustion Turbine	21.8%	19.3%	19.2%	2.5%	2.6%
Diesel	15.1%	14.7%	6.5%	0.5%	8.6%
Hydroelectric	3.0%	1.2%	1.0%	1.8%	2.0%
Nuclear	2.0%	2.0%	2.8%	0.0%	(0.8%)
Steam	13.6%	13.3%	11.6%	0.3%	2.0%
Total	11.2%	10.6%	9.6%	0.7%	1.6%

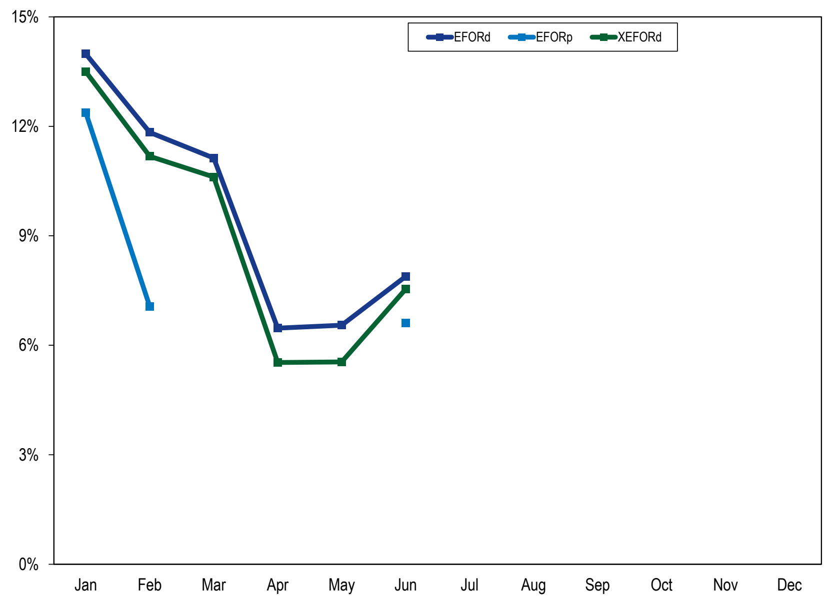
81 See PJM. "Manual 22: Generator Resource Performance Indices," Revision 16 (November 16, 2011), Definitions.

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

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 non-OMC outages during peak hours than would have been expected based on EFORd.

Figure 5-10 PJM EFORd, XEFORd and EFORp: January through June 2014



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 June 2014