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 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 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

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 State of the Market Report for PJM*, Section 5, "Capacity Market," and include all capacity within the PJM footprint.

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

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

Incremental Auction may be held if there is a need to procure additional capacity resulting from a delay in a planned large transmission upgrade that was modeled in the BRA for the relevant Delivery Year.[7]

RPM prices are locational and may vary depending on transmission constraints.[8] Existing generation capable of qualifying as a capacity resource must be offered into RPM Auctions, except for resources owned by entities that elect the fixed resource requirement (FRR) option. Participation by LSEs is mandatory, except for those entities that elect the FRR option. There is an administratively determined demand curve that defines scarcity pricing levels and that, with the supply curve derived from capacity offers, determines market prices in each BRA. RPM rules provide performance incentives for generation, including the requirement to submit generator outage data and the linking of capacity payments to the level of unforced capacity, 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.

Market Structure

- **PJM Installed Capacity.** During 2014, PJM installed capacity increased 628.9 MW or 0.3 percent from 183,095.2 MW on January 1 to 183,724.1 MW on December 31. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity on December 31, 2014, 39.7 percent was coal; 30.7 percent was gas; 17.9 percent was nuclear; 6.0 percent was oil; 4.8 percent was hydroelectric; 0.4 percent was wind; 0.4 percent was solid waste; and 0.1 percent was solar.
- **Supply.** Total internal capacity available to offer in the Base Residual Auction for the relevant Delivery Year increased 11,557.6 MW from 184,678.2 MW on June 1, 2013, to 196,235.8 MW on June 1, 2014. This increase was the result of a correction in resource modeling (-31.2 MW), the integration of capacity resources in the Duke Energy Ohio Kentucky (DEOK) Zone (4,816.8 MW), new generation (1,038.5 MW), reactivated generation (8.1 MW), net generation capacity modifications (cap mods) (-991.9 MW), Demand Resource (DR) modifications (6,940.0 MW), Energy Efficiency (EE) modifications (49.4 MW), the EFORd effect due to higher sell offer EFORds (-271.7 MW), and lower load management UCAP conversion factor (-0.4 MW).
- **Demand.** There was a 4,537.5 MW increase in the RPM reliability requirement from 173,549.0 MW on June 1, 2013, to 178,086.5 MW on June 1, 2014. The 4,537.5 MW increase in the RTO Reliability Requirement was a result of a 4,455.1 MW increase in the forecast peak load in UCAP terms holding the FPR constant at the 2013/2014 level plus 82.4 MW attributable to the change in the FPR. On June 1, 2014, PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 71.1 percent, down slightly from 72.0 percent on June 1, 2013.
- **Market Concentration.** In the 2014/2015 RPM First Incremental Auction, 2014/2015 RPM Second Incremental Auction, 2014/2015 RPM Third Incremental Auction, 2015/2016 RPM Base Residual Auction, 2015/2016 RPM First Incremental Auction, 2015/2016 RPM Second Incremental Auction, 2016/2017 RPM Base Residual Auction, 2016/2017 RPM First Incremental Auction, and 2017/2018 PM Base Residual Auction, all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[9] In the 2014/2015 RPM Base Residual Auction, all participants in the RTO and PSEG North RPM markets failed the TPS test, and seven participants in the incremental supply in MAAC passed the TPS test. 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

7 See 126 FERC ¶ 61,275 (2009) at P 88.

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

9 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).

cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[10 11 12]

- **Imports and Exports.** Net exchange increased 917.6 MW from June 1, 2013 to June 1, 2014. Net exchange, which is imports less exports, increased due to a decrease in imports of 292.7 MW and a decrease in exports of 1,210.3 MW.
- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs increased by 1,003.6 MW from 8,490.0 MW on June 1, 2013 to 9,493.6 MW on June 1, 2014 as a result of an increase in cleared capacity for Demand Resources (4,163.4 MW), an increase in cleared capacity for Energy Efficiency Resources (173.5 MW), and a decrease in replacement capacity for Energy Efficiency Resources (79.7 MW), offset by an increase in replacement capacity for Demand Resources (3,413.0 MW).

Market Conduct

- **2014/2015 RPM Base Residual Auction.** Of the 1,152 generation resources which submitted offers, unit-specific offer caps were calculated for 154 generation resources (13.4 percent). The MMU calculated offer caps for 709 generation resources (61.5 percent), of which 561 were based on the technology specific default (proxy) ACR values.
- **2014/2015 RPM First Incremental Auction.** Of the 190 generation resources which submitted offers, unit-specific offer caps were calculated for 26 generation resources (13.7 percent). The MMU calculated offer caps for 96 generation resources (50.5 percent), of which 71 were based on the technology specific default (proxy) ACR values.
- **2014/2015 RPM Second Incremental Auction.** Of the 221 generation resources which submitted offers, unit-specific offer caps were calculated for six generation resources (2.7 percent). The MMU calculated offer caps for 72 generation resources (32.6 percent), of which 67 were based on the technology specific default (proxy) ACR values.
- **2014/2015 RPM Third Incremental Auction.** Of the 404 generation resources which submitted offers, unit-specific offer caps were calculated for six generation resources (1.5 percent). The MMU calculated offer caps for 19 generation resources (4.7 percent), of which 13 were based on the technology specific default (proxy) ACR values.
- **2015/2016 RPM Base Residual Auction.** Of the 1,168 generation resources which submitted offers, unit-specific offer caps were calculated for 196 generation resources (16.8 percent). The MMU calculated offer caps for 670 generation resources (57.4 percent), of which 478 were based on the technology specific default (proxy) ACR values.
- **2015/2016 RPM First Incremental Auction.** Of the 131 generation resources which submitted offers, unit-specific offer caps were calculated for 20 generation resources (15.3 percent). The MMU calculated offer caps for 45 generation resources (34.4 percent), of which 25 were based on the technology specific default (proxy) ACR values.
- **2015/2016 RPM Second Incremental Auction.** Of the 80 generation resources which submitted offers, unit-specific offer caps were calculated for 16 generation resources (20.0 percent). The MMU calculated offer caps for 25 generation resources (31.3 percent), of which nine were based on the technology specific default (proxy) ACR values.
- **2016/2017 RPM Base Residual Auction.** Of the 1,199 generation resources which submitted offers, unit-specific offer caps were calculated for 152 generation resources (12.7 percent). The MMU calculated offer caps for 638 generation resources (53.2 percent), of which 491 were based on the technology specific default (proxy) ACR values.
- **2016/2017 RPM First Incremental Auction.** Of the 115 generation resources which submitted offers, unit-specific offer caps were calculated for 37 generation resources (32.2 percent). The MMU calculated offer caps for 62 generation resources (53.9 percent), of which 25 were based on the technology specific default (proxy) ACR values.
- **2017/2018 RPM Base Residual Auction.** Of the 1,202 generation resources which submitted offers, unit-

10 See PJM. OATT Attachment DD § 6.5.

11 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.

12 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).

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

- RPM net excess decreased 1,046.0 MW from 6,518.3 MW on June 1, 2013, to 5,472.3 MW on June 1, 2014.
- For the 2014/2015 Delivery Year, RPM annual charges to load totaled approximately $7.3 billion.
- The Delivery Year weighted average capacity price was $116.55 per MW-day in 2013/2014 and $126.40 per MW-day in 2014/2015.

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd for 2014 was 9.4 percent, an increase from 8.1 percent for 2013.[13]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor for 2014 was 82.3 percent, a decrease from 83.6 percent for 2013.
- **Outages Deemed Outside Management Control (OMC).** In 2014, 7.7 percent of forced outages were classified as OMC outages, and 6.8 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.

Recommendations[14]

The MMU recognizes that PJM has proposed the Capacity Performance construct to replace some of the existing core market rules and to address fundamental performance incentive issues. The MMU recognizes that the Capacity Performance construct addresses many of the MMU's recommendations. Until new rules are in place, the MMU's recommendations and the reported status of those recommendations are based on the existing capacity market rules.

- 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.[15] [16] (Priority: High. First reported 2013. Status: Not adopted.)
- 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. (Priority: High. First reported 2013. Status: Not adopted.)
- 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. (Priority: Medium. First reported 2013. Status: Not adopted.)
- 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. (Priority: Medium. First reported 2013. Status: Not adopted.)
- 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. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that clear, explicit operational protocols be defined for recalling the energy output of Capacity Resources when PJM is

13 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 year ending December 31, as downloaded from the PJM GADS database on January 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.

14 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. See Table 5-2 RPM related MMU reports, 2013 through 20145-2.

15 See also Comments of the Independent Market Monitor for PJM. Docket No. ER14-503-000 (December 20, 2013).

16 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).

in an emergency condition. PJM has modified these protocols, but they need additional clarification and operational details. (Priority: Low. First reported 2013. Status: Not adopted.)

- 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. (Priority: High. First reported 2013. Status: Not adopted.)
  - **The MMU recommends that a unit which is not capable of supplying energy consistent with its day-ahead offer should reflect an appropriate outage.** (Priority: Medium. First reported 2013. Status: Not adopted.)
  - **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.** (Priority: Medium. First reported 2013. Status: Not adopted.)
  - **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.**[17] (Priority: Medium. First reported 2013. Status: Not adopted.)

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 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 2014.

The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[18] [19] [20] [21] [22] 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.[23]

The MMU continues to recommend that the use of the 2.5 percent demand adjustment be terminated immediately.[24] 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

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

18 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).

19 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).

20 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).

21 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).

22 See "Analysis of the 2017/2018 RPM Base Residual Auction," <*http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Analysis_of_the_2017_2018_RPM_Base_Residual_Auction_20141006.pdf*> (October 6, 2014).

23 See "The 2017/2018 RPM Base Residual Auction: Sensitivity Analyses Revised," <*http://www.monitoringanalytics.com/reports/Reports/2014/IMM_20172018_RPM_BRA_Sensitivity_Analyses_Revised_20140826.pdf*> (August 26, 2014).

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

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 is 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.

Table 5-2 RPM related MMU reports, 2013 through 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	IMM 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
August 26, 2014	The 2017/2018 RPM Base Residual Auction: Sensitivity Analyses Revised http://www.monitoringanalytics.com/reports/Reports/2014/IMM_20172018_RPM_BRA_Sensitivity_Analyses_Revised_20140826.pdf
August 29, 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_20140829.pdf
September 3, 2014	2017/2018 RPM BRA Sensitivity Analysis http://www.monitoringanalytics.com/reports/Presentations/2014/IMM_MIC_20172018_Sensitivity_Analyses_Revised_20140903.pdf
September 15, 2014	Capacity Performance Product Assumptions http://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_ELC_Capacity_Performance_Product_Assumptions_20140915.pdf
September 17, 2014	IMM Comments on PJM's Capacity Performance Proposal and IMM Proposal http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Comments_on_PJM's_Capacity_Performance_Proposal_and_IMM_Proposal_20140917.pdf
October 6, 2014	Analysis of the 2017/2018 RPM Base Residual Auction http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Analysis_of_the_2017_2018_RPM_Base_Residual_Auction_20141006.pdf
October 16, 2014	IMM Comments re PJM Triennial Review Docket No. ER14-2940-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Comments_ER14-2940-000_20141016.pdf
October 22, 2014	IMM Comments re FE Complaint Docket No. EL14-55-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Comments_Docket_No_EL14-55-000_20141022.pdf
October 28, 2014	IMM Proposal re PJM's Capacity Performance Proposal http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Proposal_re_PJM_Capacity_Performance_Proposal_20141028.pdf
November 19, 2014	IMM Motion to Intervene and Comments re 30 Day Notice Exception Docket No. ER15-135-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Motion_to_Intervene_and_Comments_Docket_No_ER15-135-000_20141119.pdf
December 3, 2014	IMM Reply Brief re Net Revenues Docket No. EL14-94-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Reply_Brief_Docket_No_EL14-94-000_20141203.pdf
December 12, 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_20141212.pdf
December 17, 2014	IMM Answer and Motion for Leave to Answer re Net Revenues Docket No. EL14-94-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Answer_and_Motion_to_Answer_Docket_No_EL14-94-000_20141217.pdf
December 18, 2014	IMM Answer and Motion for Leave to Answer re DR Docket No. ER15-135-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Answer_and_Motion_to_Answer_Docket_No_ER15-135-000_20141218.pdf

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

	1-Jan-14		31-May-14		1-Jun-14		31-Dec-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%	73,015.3	39.7%
Gas	53,395.0	29.2%	53,841.6	29.4%	55,041.7	29.9%	56,364.5	30.7%
Hydroelectric	8,106.7	4.4%	8,135.7	4.4%	8,463.8	4.6%	8,765.3	4.8%
Nuclear	33,076.7	18.1%	33,073.7	18.0%	32,891.0	17.9%	32,947.1	17.9%
Oil	11,314.2	6.2%	11,290.4	6.2%	11,155.7	6.1%	10,931.7	6.0%
Solar	84.2	0.0%	84.2	0.0%	94.7	0.1%	97.5	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%	822.7	0.4%
Total	183,095.2	100.0%	183,252.4	100.0%	184,009.1	100.0%	183,724.1	100.0%

Installed Capacity

On January 1, 2014, PJM installed capacity was 183,095.2 MW (Table 5-3).[25] Over the next twelve months, new generation, unit deactivations, facility reratings, plus import and export shifts resulted in PJM installed capacity of 183,724.1 MW on December 31, 2014, an increase of 628.9 MW or 0.3 percent over the January 1 level.[26] [27] The 628.9 MW increase was the result of an increase in imports (2,387.0 MW), new or reactivated generation (1,720.0 MW), capacity modifications (386.0 MW), offset by deactivations (3,270.3 MW), derates (497.5 MW), and an increase in exports (96.3 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.

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.[28] In 2014, a Third Incremental Auction was held in February for the 2014/2015 Delivery Year, a Base Residual Auction was held in May for the 2017/2018 Delivery Year, a Second Incremental Auction was held in July for the 2015/2016 Delivery Year, and a First Incremental Auction was held in September for the 2016/2017 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).

As shown in Table 5-5, total internal capacity available to offer in the Base Residual Auction for the relevant Delivery Year increased 11,557.6 MW from 184,678.2 MW on June 1, 2013, to 196,235.8 MW on June 1, 2014. This increase was the result of a correction in resource modeling (-31.2 MW), the integration of capacity resources in the Duke Energy Ohio Kentucky (DEOK) Zone (4,816.8 MW), new generation (1,038.5 MW), reactivated generation (8.1 MW), net generation

25 Percent values shown in Table 5-3 PJM installed capacity (By fuel source): January 1, May 31, June 1, and December 31, 20145-3 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

26 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.

27 Wind resources accounted for 822.7 MW of installed capacity in PJM on December 31, 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.

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

capacity modifications (cap mods) (-991.9 MW), Demand Resource (DR) modifications (6,940.0 MW), Energy Efficiency (EE) modifications (49.4 MW), the EFORd effect due to higher sell offer EFORds (-271.7 MW), and lower load management UCAP conversion factor (-0.4 MW). The EFORd effect is the measure of the net internal capacity change attributable to EFORd changes and not capacity modifications.

In the 2015/2016, 2016/2017, and 2017/2018 auctions, new generation were 17,482.8 MW; reactivated generation were 1,777.5 MW and net generation cap mods were -16,435.3 MW. DR and Energy Efficiency (EE) modifications totaled 8,079.6 MW through June 1, 2017. A decrease of 189.7 MW was due to lower EFORds, and an increase of 95.1 MW was due to a higher Load Management UCAP conversion factor. The integration of the East Kentucky Power Cooperative (EKPC) Zone resources added 2,735.7 MW to total internal capacity. The net effect from June 1, 2014, through June 1, 2017, was a decrease in total internal capacity available to offer in the Base Residual Auction for the relevant Delivery Year of 2,613.5 MW (1.4 percent) from 196,235.8 MW to 193,622.3 MW.

As shown in Table 5-5 and Table 5-13, in the 2014/2015 auction, the 43 additional generation resources offered consisted of 39 new resources (1,038.5 MW), two additional resources imported (577.6 MW), one reactivated resource (8.1 MW), and one Duke Energy Ohio and Kentucky (DEOK) integration resource (22.5 MW). The new Generation Capacity Resources consisted of 17 solar resources (30.2 MW), seven wind resources (146.6 MW), seven diesel resources (31.5 MW), five hydroelectric resources (132.7), two CT units (76.7 MW), and one combined cycle unit (620.8 MW). The reactivated Generation Capacity Resources consisted of one diesel resource (8.1 MW). The 61 fewer generation resources offered consisted of 12 deactivated resources (936.8 MW), 12 additional resources excused from offering (1,129.9 MW), 32 additional resources committed fully to FRR (2,175.0 MW), four Planned Generation Capacity Resources not offered (240.0 MW), and one external generation resource not offered (6.6 MW). In addition, there were the following retirements of resources that were either exported or excused in the 2013/2014 BRA: two combustion turbine (CT) units (2.5 MW).

As shown in Table 5-5 and Table 5-14, in the 2015/2016 auction, the 111 additional generation resources offered consisted of 49 new resources (6,221.0 MW), 45 resources that were previously entirely FRR committed (4,803.0 MW), 13 additional resources imported (1,072.2 MW), three resources that were excused and not offered in the 2014/2015 BRA (30.8 MW), and one Duke Energy Ohio and Kentucky (DEOK) integration resource not offered in the 2014/2015 BRA (42.7 MW). The new Generation Capacity Resources consisted of 15 solar resources (13.8 MW), eight CT resources (1,348.4 MW), seven combined cycle resources (4,526.9 MW), six wind resources (104.9 MW), five diesel resources (13.6 MW), five hydroelectric resources (143.6 MW), two fuel cell resources (28.5 MW), and one steam unit (41.3 MW). In addition, there were the following new generation resources that were not offered in to the auction because they were either exported or entirely committed to FRR for the 2015/2016 Delivery Year: two CT resources (283.6 MW). The 95 fewer generation resources offered consisted of 49 additional resources excused from offering (3,761.1 MW), 29 deactivated resources (3,713.2 MW), eight additional resources committed fully to FRR (471.8 MW), three less resources resulting from aggregation of RPM resources, three external resources not offered (866.4 MW), one resource that is no longer a PJM capacity resource (1.2 MW), one Planned Generation Capacity Resource not offered (1.5 MW), and one resource unoffered and unexcused (4.8 MW). In addition, there were the following retirements of resources that were either exported, excused, or committed to an FRR capacity plan in the 2014/2015 BRA: six steam units (918.5 MW).

As shown in Table 5-5 and Table 5-15, in the 2016/2017 auction, the 99 additional generation resources offered consisted of 36 new resources (4,900.8 MW), 29 additional resources imported (3,026.3 MW), 18 East Kentucky Power Cooperative (EKPC) integration resources not offered in the 2015/2016 BRA (2,537.3 MW), nine resources that were excused and not offered in the 2015/2016 BRA (1,033.9 MW), three repowered resources (920.2 MW), two resources that were previously entirely FRR committed (168.3 MW), one reactivated resource (17.6 MW), and one additional resource resulting from the disaggregation of an RPM resource. The 36 new Generation Capacity Resources consisted of 11 diesel resources (36.1 MW), nine solar resources (32.1 MW), eight combined cycle resources (4,597.2 MW), five wind resources (54.3 MW), two CT resources (159.3 MW), and one steam unit (21.8 MW). In addition, there were new generation resources that were not offered in to the auction because they were either exported or entirely committed to FRR for the 2016/2017 Delivery Year: one wind resource (12.8 MW) and one diesel resource (5.3 MW). The 68 fewer generation resources offered consisted of 33 additional resources excused from offering (1,706.0 MW), 28 deactivated resources (1,389.6 MW), three fewer resources resulting from aggregation of RPM resources, two additional resources committed fully to FRR (28.7 MW), and two Planned Generation Capacity Resources not offered (934.8 MW). In addition, there were the following retirements of resources that were either exported, excused, or committed to an FRR capacity plan in the 2015/2016 BRA: 25 steam units (2,207.1 MW) and 13 CT resources (245.0 MW).

As shown in Table 5-5 and Table 5-16, in the 2017/2018 auction the 51 additional generation resources offered consisted of 32 new resources (5,103.3 MW), six repowered resources (941.6 MW), four resources that were excused and not offered in the 2016/2017 BRA (384.6 MW), three additional resources imported (714.1 MW), three resources that were previously entirely FRR committed (164.0 MW), two additional resources resulting from the disaggregation of RPM resources, and one reactivated resource (84.1 MW). The 32 new Generation Capacity Resources consisted of 15 solar resources (27.0 MW), nine diesel resources (122.5 MW), six combined cycle resources (4,825.4 MW), one CT resource (122.7 MW), and one hydro resource (5.7 MW). In addition, there were new generation resources that were not offered in to the auction because they were either exported or entirely committed to FRR for the 2017/2018 Delivery Year: one wind resource (26.0 MW).

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 Internal capacity: June 1, 2012 to June 1, 2016[29]

	UCAP (MW)												
	RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ATSI Cleveland	ComEd	BGE	PPL
Total internal capacity @ 01-Jun-13	184,678.2	69,078.9	33,700.6	11,768.3	1,612.4	8,035.6	4,174.8	5,288.9					
184,678.2	(31.2)	0.0	11,768.3	0.0	0.0	0.0	0.0	0.0					
69,078.9	184,647.0	69,078.9	1,612.4	11,768.3	1,612.4	8,035.6	4,174.8	5,288.9					
33,700.6	4,816.8	0.0	8,035.6	0.0	0.0	0.0	0.0	0.0					
11,768.3	1,038.5	875.8	4,174.8	2.7	48.0	6.8	1.5	0.0					
1,612.4	8.1	8.1	5,288.9	0.0	0.0	8.1	0.0	0.0					
8,035.6	(991.9)	(175.2)	(102.3)	(242.8)	(161.9)	9.3	(0.5)	(2.8)					
4,174.8	6,940.0	6,653.8	2,438.6	2,727.5	241.9	547.0	205.0	681.7					
5,288.9	49.4	55.6	1.2	52.0	3.0	(0.6)	(0.6)	7.5					
EFORd effect	(271.7)	(248.0)	(93.5)	54.1	(17.8)	104.8	25.5	106.4					
DR and EE effect	(0.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0					
Total internal capacity @ 01-Jun-14	196,235.8	76,249.0	36,649.9	14,361.8	1,725.6	8,711.0	4,405.7	6,081.7	10,545.2				
New generation	6,786.1	3,486.9	2,523.3	661.0	297.7	801.0	793.9	661.0	843.8				
Reactivated generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0				
Generation cap mods	(5,118.9)	(361.0)	7.0	(372.3)	(2.0)	(138.9)	5.5	(372.3)	74.4				
DR mods	5,441.4	(149.6)	606.9	(1,583.0)	(123.8)	(33.9)	(70.7)	(34.8)	2,729.0				
EE mods	220.1	29.4	25.4	(3.0)	(5.0)	5.1	3.5	12.9	78.2				
EFORd effect	938.4	508.9	229.8	156.4	7.0	170.3	87.9	114.4	133.6				
DR and EE effect	54.4	29.5	12.8	6.2	0.9	4.0	2.0	3.4	3.3				
Total internal capacity @ 01-Jun-15	204,557.3	79,793.1	40,055.1	13,227.1	1,900.4	9,518.6	5,227.8	6,466.3	14,407.5	3,484.3			
Integration of existing EKPC resources	2,735.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0			
New generation	5,517.4	2,291.3	606.5	3.6	0.0	30.2	0.0	0.0	767.1	0.0			
Reactivated generation	751.8	751.8	751.8	0.0	0.0	17.6	0.0	0.0	0.0	0.0			
Generation cap mods	(3,373.3)	(2,385.3)	(1,320.6)	(70.4)	(2.8)	(241.3)	(108.7)	0.0	(92.3)	0.0			
DR mods	(10,690.1)	(6,472.2)	(3,268.1)	(1,030.2)	(139.0)	(986.6)	(428.4)	(428.7)	(791.4)	564.7			
EE mods	262.5	145.6	28.7	85.6	0.7	3.2	0.7	50.4	131.0	55.7			
EFORd effect	1,039.0	575.2	160.5	325.3	6.8	(0.6)	(0.6)	146.4	(101.8)	(69.6)			
DR and EE effect	47.8	18.4	7.0	6.8	0.2	2.1	0.8	3.0	5.1	0.0			
Total internal capacity @ 01-Jun-16	200,848.1	74,717.9	37,020.9	12,547.8	1,766.3	8,343.2	4,691.6	6,237.4	14,325.2	4,035.1	26,091.2	3,717.0	10,570.7
Correction in resource modeling	0.0	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Adjusted internal capacity @ 01-Jun-16	200,848.1	74,718.7	37,020.9	12,547.8	1,766.3	8,343.1	4,691.6	6,237.4	14,325.2	4,035.1	26,091.2	3,717.0	10,570.7
New generation	5,179.3	3,599.6	1,663.2	856.3	0.0	2.8	0.0	0.0	770.2	0.0	3.4	122.7	959.9
Reactivated generation	1,025.7	1,025.7	84.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Generation cap mods	(7,943.1)	(2,286.3)	(2,190.4)	(57.8)	5.7	(1,135.2)	(509.9)	15.8	(751.7)	(818.0)	85.0	0.0	(49.9)
DR mods	(3,472.4)	(941.6)	(407.6)	(198.9)	(33.0)	(167.9)	(50.2)	(54.4)	(889.9)	(208.7)	497.8	635.1	(171.2)
EE mods	158.9	91.4	26.9	61.5	0.9	4.4	0.1	77.2	(58.4)	(14.6)	583.3	50.9	(1.0)
EFORd effect	(2,167.1)	(987.4)	(267.1)	(329.7)	(19.8)	(122.1)	(62.0)	35.1	(529.7)	(77.2)	33.6	(361.9)	(236.1)
DR and EE effect	(7.1)	(2.5)	(1.4)	(0.4)	(0.2)	(0.4)	(0.2)	(0.3)	(1.3)	(0.4)	(1.0)	(0.1)	(0.3)
Total internal capacity @ 01-Jun-17	193,622.3	75,217.6	35,928.6	12,878.8	1,719.9	6,924.7	4,069.4	6,310.8	12,864.4	2,916.2	27,293.3	4,163.7	11,072.1

29 The RTO includes MAAC, EMAAC, SWMAAC, and ATSI. MAAC includes EMAAC, SWMAAC, and PPL. EMAAC includes DPL South, PSEG and PSEG North. PSEG includes PSEG North. SWMAAC includes Pepco and BGE. ATSI includes ATSI Cleveland.

Table 5-6 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

There was a 4,537.5 MW increase in the RPM reliability requirement from 173,549.0 MW on June 1, 2013, to 178,086.5 MW on June 1, 2014. The 4,537.5 MW increase in the RTO Reliability Requirement was a result of a 4,455.1 MW increase in the forecast peak load in UCAP terms holding the FPR constant at the 2013/2014 level plus 82.4 MW attributable to the change in the FPR.

The MMU analyzed market sectors in the PJM Capacity Market to determine how they met their load obligations. The Capacity Market was divided into the following sectors:

- **PJM EDC.** EDCs with a franchise service territory within the PJM footprint. This sector includes traditional utilities, electric cooperatives, municipalities and power agencies.
- **PJM EDC Generating Affiliate.** Affiliate companies of PJM EDCs that own generating resources.
- **PJM EDC Marketing Affiliate.** Affiliate companies of PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-PJM EDC.** EDCs with franchise service territories outside the PJM footprint.
- **Non-PJM EDC Generating Affiliate.** Affiliate companies of non-PJM EDCs that own generating resources.
- **Non-PJM EDC Marketing Affiliate.** Affiliate companies of non-PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-EDC Generating Affiliate.** Affiliate companies of non-EDCs that own generating resources.
- **Non-EDC Marketing Affiliate.** Affiliate companies of non-EDCs that sell power and have load obligations in PJM, but do not own generating resources.

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 5-6), 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 5-7, all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test in the 2014/2015 RPM First Incremental Auction, 2014/2015 RPM Second Incremental Auction, 2014/2015 RPM Third Incremental Auction, 2015/2016 RPM Base Residual Auction, 2015/2016 RPM First Incremental Auction, 2015/2016 RPM Second Incremental Auction, 2016/2017 RPM Base Residual Auction, 2016/2017 RPM First Incremental Auction, and the 2017/2018 RPM Base Residual Auction.[30] In the 2014/2015 RPM Base Residual Auction, all participants in the RTO and PSEG North RPM markets failed the TPS test, and seven participants in the incremental supply in MAAC passed the TPS test. 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

30 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.

clearing price.[31] [32] [33] In applying the market structure test, the relevant supply for the RTO market includes all supply offered at less than or equal to 150 percent of the RTO cost-based clearing price.[34] The relevant supply for the constrained LDA markets includes the incremental supply inside the constrained LDAs which was offered at a price higher than the unconstrained clearing price for the parent LDA market and less than or equal to 150 percent of the cost-based clearing price for the constrained LDA. The relevant demand consists of the MW needed inside the LDA to relieve the constraint.

Table 5-7 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. The results of the TPS are measured by the residual supply index (RSIx). The RSIx is a general measure that can be used with any number of pivotal suppliers. The subscript denotes the number of pivotal suppliers included in the test. If the RSIx is less than or equal to 1.0, the supply owned by the specific generation owner, or owners, is needed to meet market demand and the generation owners are pivotal suppliers with a significant ability to influence market prices. If the RSIx is greater than 1.0, the supply of the specific generation owner or owners is not needed to meet market demand and those generation owners have a reduced ability to unilaterally influence market price.

Table 5-7 RSI results: 2014/2015 through 2017/2018 RPM Auctions[35]

RPM Markets	RSI1, 1.05	RSI3	Total Participants	Failed RSI3 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
2015/2016 Second Incremental Auction				
RTO	0.40	0.21	26	26
MAAC	0.00	0.04	4	4
PSEG	0.00	0.00	0	0
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
2016/2017 First Incremental Auction				
RTO	0.58	0.16	29	29
MAAC	0.26	0.00	3	3
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

31 See PJM. OATT Attachment DD § 6.5.

32 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.

33 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).

34 Effective November 1, 2009, DR and EE resources are not included in the TPS test. See 129 FERC ¶ 61,081 (2009) at P 31.

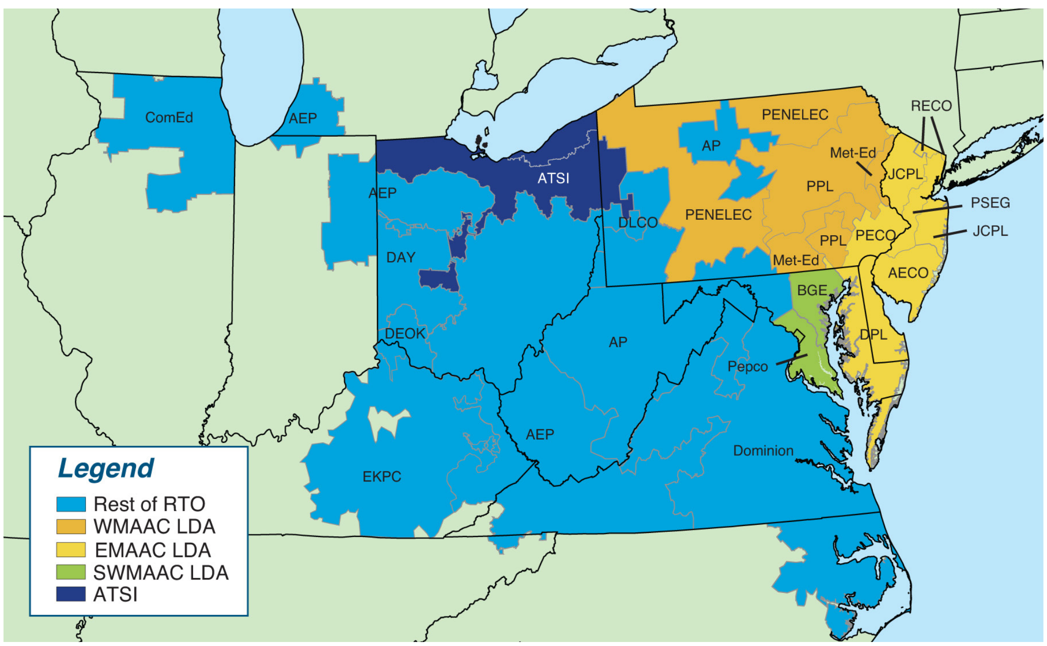
35 The RSI shown is the lowest RSI in the market.

Locational Deliverability Areas (LDAs)

Under the PJM Tariff, PJM determines, in advance of each BRA, whether defined Locational Deliverability Areas (LDAs) will be modeled in the auction. Effective with the 2012/2013 Delivery Year, an LDA is 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 are 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.

Figure 5-1 Map of PJM Locational Deliverability Areas



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

38 146 FERC ¶ 61,052 (2014).

Figure 5-2 Map of PJM RPM EMAAC subzonal LDAs

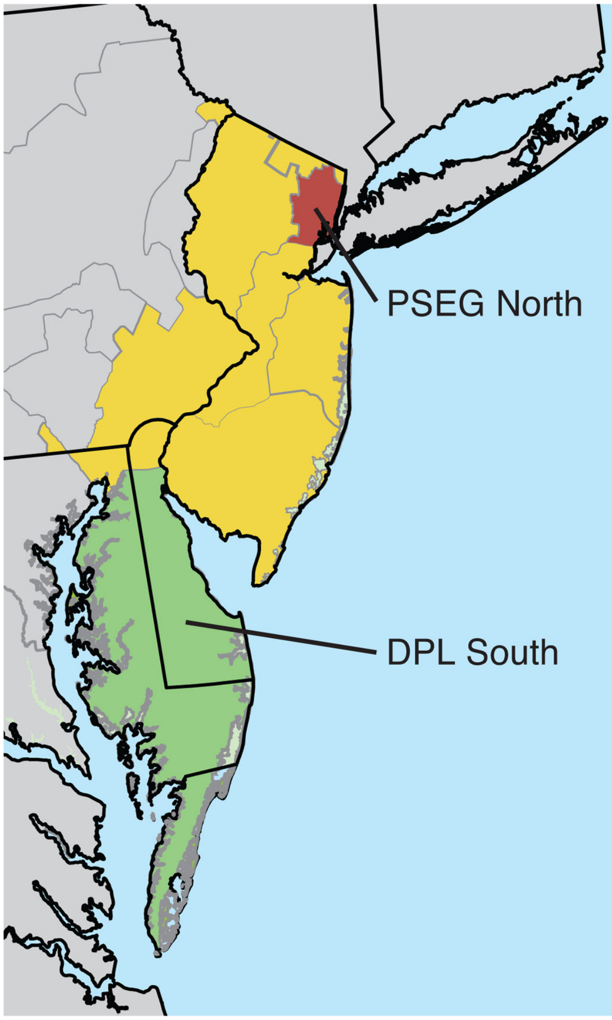
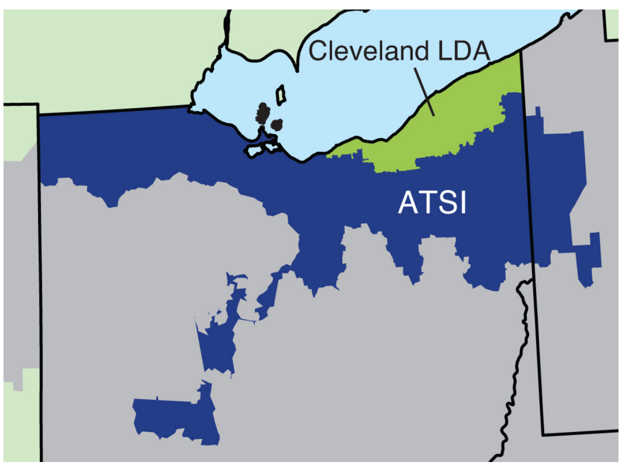


Figure 5-3 Map of PJM RPM ATSI subzonal LDA



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]

As shown in Table 5-8, net exchange increased 917.6 MW from June 1, 2013 to June 1, 2014. Net exchange, which is imports less exports, increased due to a decrease in imports of 292.7 MW and a decrease in exports of 1,210.3 MW.

As shown in Table 5-9, 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.

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.

Importing Capacity

Existing External Generation Capacity Resource

Generation external to the PJM region is eligible to be offered into an RPM Auction if it meets specific

39 PJM. OATT Attachment DD § 5.6.6(b).

requirements.[40] [41] Firm transmission service from the unit to the border of PJM and generation deliverability into PJM must be demonstrated prior to the start of the delivery year. In order to demonstrate generation deliverability into PJM, external generators must obtain firm point-to-point transmission service on the PJM OASIS from the PJM border into the PJM transmission system or by obtaining network external designated transmission service. In the event that transmission upgrades are required to establish deliverability, those upgrades must be completed by the start of the delivery year. The following are also required: the external generating unit must be in the resource portfolio of a PJM member; twelve months of NERC/GADs unit performance data must be provided to establish an EFORd; the net capability of each unit must be verified through winter and summer testing; a letter of non-recallability must be provided to assure PJM that the energy and capacity from the unit is not recallable to any other balancing authority.

All external generation resources that have an RPM commitment or FRR capacity plan commitment or that are designated as replacement capacity must be offered in the PJM Day-Ahead Energy Market.[42]

To avoid balancing market deviations, any offer accepted in the Day-Ahead Energy Market must be scheduled to physically flow in the Real-Time Energy Market. When submitting the real-time energy market transaction, a valid NERC Tag is required, with the appropriate transmission reservations associated. Additionally, external capacity transactions must designate the transaction as such when submitting the NERC Tag. This designation allows the PJM dispatch operators to identify capacity backed transactions in order to avoid curtailing them out of merit order. External capacity backed transactions are evaluated the same way as all other energy transactions and are subject to all scheduling timing requirements and PJM interchange ramp limits. If the offer is not accepted in the Day-Ahead Energy Market, but the unit is requested during the operating day, the PJM dispatch operator will notify the participant. The market participant will then submit a tag to match the request. This tag will also be subject to all scheduling timing requirements and PJM interchange ramp limits.

40 See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 9 & 10.
41 See PJM. "Manual 18: PJM Capacity Market," Revision 27 (January 2, 2015), pp. 45-46 & p. 66.
42 OATT, Schedule 1, Section 1.10.1A.

Planned External Generation Capacity Resource

Planned External Generation Capacity Resources are eligible to be offered into an RPM Auction if they meet specific requirements.[43] [44] Planned External Generation Capacity Resources are proposed Generation Capacity Resources, or a proposed increase in the capability of an Existing Generation Capacity Resource, that is located outside the PJM region; participates in the generation interconnection process of a balancing authority external to PJM; is scheduled to be physically and electrically interconnected to the transmission facilities of such balancing authority on or before the first day of the delivery year for which the resource is to be committed to satisfy the reliability requirements of the PJM Region; and is in full commercial operation prior to the first day of the delivery year.[45] An External Generation Capacity Resource becomes an Existing Generation Capacity Resource as of the earlier of the date that interconnection service commences or the resource has cleared an RPM Auction.[46]

Exporting Capacity

Non-firm transmission can be used to export capacity from the PJM region. A Generation Capacity Resource located in the PJM region not committed to service of PJM loads may be removed from PJM Capacity Resource status if the Capacity Market Seller shows that the resource has a financially and physically firm commitment to an external sale of its capacity.[47] The Capacity Market Seller must also identify the megawatt amount, export zone, and time period (in days) of the export.[48]

The MMU evaluates requests submitted by Capacity Market Sellers to export Generation Capacity Resources, makes a determination as to whether the resource meets the applicable criteria to export, and must inform both the Capacity Market Seller and PJM of such determination.[49]

43 See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region", Section 1.69A.
44 See PJM. "Manual 18: PJM Capacity Market," Revision 27 (January 22, 2015), pp. 48.
45 Prior to January 31, 2011, capacity modifications to existing generation capacity resources were not considered planned generation capacity resources. See 134 FERC ¶ 61,065 (2011).
46 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation. See 134 FERC ¶ 61,065 (2011).
47 OATT Attachment DD § 6.6(g).
48 *Id.*
49 OATT Attachment M-Appendix § II.C.2.

When submitting a teal-time market export capacity transaction, a valid NERC Tag is required, with the appropriate transmission reservations associated. Capacity transactions must designate the transaction as capacity when submitting the NERC Tag. This designation allows the PJM dispatch operators to identify capacity backed transactions in order to avoid curtailing them out of merit order. External capacity backed transactions are evaluated the same way as all other energy transactions and are subject to all scheduling timing requirements and PJM interchange ramp limits.

Table 5-9 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

Table 5-8 PJM capacity summary (MW): June 1, 2007 to June 1, 2015[50 51]

	01-Jun-07	01-Jun-08	01-Jun-09	01-Jun-10	01-Jun-11	01-Jun-12	01-Jun-13	01-Jun-14	01-Jun-15	01-Jun-16	01-Jun-17
Installed capacity (ICAP)	163,721.1	164,444.1	166,916.0	168,061.5	172,666.6	181,159.7	197,775.0	210,812.4	217,829.1	216,671.5	208,605.9
Unforced capacity (UCAP)	154,076.7	155,590.2	157,628.7	158,634.2	163,144.3	171,147.8	186,588.0	199,063.2	207,738.6	207,578.0	198,282.6
Cleared capacity	129,409.2	129,597.6	132,231.8	132,190.4	132,221.5	136,143.5	152,743.3	149,974.7	164,561.2	169,159.7	167,003.7
Make-whole	0.0	0.0	0.0	0.0	43.0	222.1	14.0	112.6	2.7	0.0	65.2
RPM reliability requirement (pre-FRR)	148,277.3	150,934.6	153,480.1	156,636.8	154,251.1	157,488.5	173,549.0	178,086.5	177,184.1	180,332.2	179,545.1
RPM reliability requirement (less FRR)	125,805.0	128,194.6	130,447.8	132,698.8	130,658.7	133,732.4	149,988.7	148,323.1	162,777.4	166,127.5	165,007.1
RPM net excess	5,240.5	5,011.1	8,265.5	7,728.0	10,638.4	5,976.5	6,518.3	5,472.3	5,855.9	7,185.4	6,187.0
Imports	2,809.2	2,460.3	2,505.4	2,750.7	6,420.0	3,831.6	4,348.2	4,055.5	4,395.5	7,941.5	5,854.8
Exports	(3,938.5)	(3,838.1)	(2,194.9)	(3,147.4)	(3,158.4)	(2,637.1)	(2,438.4)	(1,228.1)	(1,214.2)	(1,211.6)	(1,194.5)
Net exchange	(1,129.3)	(1,377.8)	310.5	(396.7)	3,261.6	1,194.5	1,909.8	2,827.4	3,181.3	6,729.9	4,660.3
DR cleared	127.6	536.2	892.9	939.0	1,364.9	7,047.2	9,281.9	14,118.4	14,832.8	12,408.1	10,974.8
EE cleared						568.9	679.4	822.1	922.5	1,117.3	1,338.9
ILR	1,636.3	3,608.1	6,481.5	8,236.4	9,032.6						
FRR DR	445.6	452.8	423.6	452.9	452.9	488.1	488.6	518.1	356.8	501.9	556.2
Short-Term Resource Procurement Target						3,343.3	3,749.7	3,708.1	4,069.4	4,153.2	4,125.2

50 Prior to the 2012/2013 Delivery Year, net excess under RPM was calculated as cleared capacity plus make-whole MW less the reliability requirement plus ILR. For 2007/2008 through 2011/2012, certified ILR was used in the calculation, because the certified ILR data are now available. For the 2012/2013 Delivery Year and beyond, net excess under RPM is calculated as cleared capacity plus make-whole MW less the reliability requirement plus the Short-Term Resource Procurement Target.

51 The results for RPM Incremental Auctions are not included in this table.

Demand Resources

There are three basic demand products incorporated in the RPM market design:[52]

- **Demand Resources (DR).** Interruptible load resource that is offered into an RPM Auction as capacity and receives the relevant LDA or RTO resource clearing price.
- **Interruptible Load for Reliability (ILR).** Interruptible load resource that is not offered into the RPM Auction, but receives the final zonal ILR price determined after the second incremental auction. The ILR product was eliminated after the 2011/2012 Delivery Year.
- **Energy Efficiency (EE) Resources.** Load resources that are offered into an RPM Auction as capacity and receive the relevant LDA or RTO resource clearing price. An EE Resource is a project designed to achieve a continuous (during peak periods) reduction in electric energy consumption that is not reflected in the BRA peak load forecast for the delivery year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such delivery year, without any requirement of notice, dispatch, or operator intervention.[53] The Energy Efficiency (EE) resource type was eligible to be offered in RPM Auctions starting with the 2012/2013 Delivery Year and in incremental auctions in the 2011/2012 Delivery Year.[54]

Effective with the 2014/2015 Delivery Year, there are three types of Demand Resource products incorporated into the RPM market design:[55] [56]

- **Annual DR.** Demand Resource that is required to be available on any day in the relevant delivery year for an unlimited number of interruptions. Annual DR is required to be capable of maintaining each interruption for at least a 10-hour duration during the hours of 10:00 a.m. to 10:00 p.m. EPT for the period May through October and 6:00 a.m. to 9:00 p.m. EPT for the period November through April.
- **Extended Summer DR.** Demand Resource that is required to be available on any day from June through October and the following May in the relevant delivery year for an unlimited number of interruptions. Extended Summer DR is required to be capable of maintaining each interruption for at least a 10-hour duration during the hours of 10:00 a.m. to 10:00 p.m. EPT.
- **Limited DR.** Demand Resource that is required to be available on weekdays not including NERC holidays during the period of June through September in the relevant delivery year for up to 10 interruptions. Limited DR is required to be capable of maintaining each interruption for at least a 6-hour duration during the hours of 12:00 p.m. to 8:00 p.m. EPT.

As shown in Table 5-10 RPM load management statistics by LDA: June 1, 2013 to June 1, 20175-10 and Table 5-12 RPM load management statistics: June 1, 2007 to June 1, 20175-12, 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 5-11 RPM load management cleared capacity and ILR: 2007/2008 through 2017/20185-11 shows RPM commitments for DR and EE resources as the result of RPM Auctions prior to adjustments for replacement capacity transactions and certified ILR.

52 Effective June 1, 2007, the PJM active load management (ALM) program was replaced by the PJM load management (LM) program. Under ALM, providers had received a MW credit which offset their capacity obligation. With the introduction of LM, qualifying load management resources can be offered into RPM Auctions as capacity resources and receive the clearing price.

53 "Reliability Assurance Agreement among Load-Serving Entities in the PJM Region," Schedule 6, Section M.

54 Letter Order in Docket No. ER10-366-000 (January 22, 2010).

55 134 FERC ¶ 61,066 (2011).

56 "Reliability Assurance Agreement among Load-Serving Entities in the PJM Region," Article 1.

Table 5-10 RPM load management statistics by LDA: June 1, 2013 to June 1, 2017[57 58 59]

	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	15,129.9	6,736.2	2,656.7	2,020.9	86.3	797.9	263.5	872.7	1,827.3				
EE cleared	1,015.2	246.1	46.5	159.4	0.0	14.5	4.4	55.8	81.9				
DR net replacements	(1,153.0)	(424.1)	(284.4)	(71.3)	(11.1)	(82.4)	(52.7)	(42.1)	(220.2)				
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	14,992.1	6,558.2	2,418.8	2,109.0	75.2	730.0	215.2	886.4	1,689.0				
DR cleared	12,710.5	5,354.2	2,006.5	1,603.6	105.7	630.8	226.7	664.1	1,825.1	470.8			
EE cleared	1,157.3	338.9	70.2	209.3	0.6	21.6	7.5	83.8	198.5	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	13,867.8	5,693.1	2,076.7	1,812.9	106.3	652.4	234.2	747.9	2,023.6	523.4			
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

Table 5-11 RPM load management cleared capacity and ILR: 2007/2008 through 2017/2018[60 61]

	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	14,579.5	15,129.9	979.6	1,015.2	0.0	0.0
2016/2017	12,217.9	12,710.5	1,113.9	1,157.3	0.0	0.0
2017/2018	10,551.0	10,975.0	1,288.0	1,338.9	0.0	0.0

57 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.

58 See PJM. OATT Attachment DD § 8.4. The reported DR cleared MW may reflect reductions in the level of committed MW due to relief from Capacity Resource Deficiency Charges

59 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.

60 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.

61 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.

Table 5-12 RPM load management statistics: June 1, 2007 to June 1, 2017[62 63]

	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	15,559.1	16,145.1	(1,111.0)	(1,153.0)	0.0	0.0	14,448.1	14,992.1
01-Jun-16	13,331.8	13,867.8	0.0	0.0	0.0	0.0	13,331.8	13,867.8
01-Jun-17	11,839.0	12,313.9	0.0	0.0	0.0	0.0	11,839.0	12,313.9

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.[64 65 66]

Avoidable costs are the costs that a generation owner would not incur if the generating unit did not operate for one year, in particular the delivery year.[67] In the calculation of avoidable costs, there is no presumption that the unit would retire as the alternative to operating, although that possibility could be reflected if the owner documented that retirement was the alternative. Avoidable costs may also include annual capital recovery associated with investments required to maintain a unit as a Generation Capacity Resource, termed Avoidable Project Investment Recovery (APIR). Avoidable cost based offer caps are defined to be net of revenues from all other PJM markets and unit-specific bilateral contracts. Capacity resource owners could provide ACR data by providing their own unit-specific data or by selecting the default ACR values. The specific components of avoidable costs are defined in the PJM Tariff.[68]

The opportunity cost option allows Capacity Market Sellers to input a documented price available in a market external to PJM, subject to export limits. If the relevant RPM market clears above the opportunity cost, the Generation Capacity Resource is sold in the RPM market. If the opportunity cost is greater than the clearing price and the Generation Capacity Resource does not clear in the RPM market, it is available to sell in the external market.

Effective April 12, 2011, the RPM Minimum Offer Price Rule (MOPR) was changed.[69] The changes to the MOPR included updating the calculation of the net Cost of New Entry (CONE) for combined cycle (CC) and combustion turbine (CT) plants which is used as a benchmark value in assessing the competitiveness of a sell offer, increasing the percentage value used in the screen to 90 percent for CC and CT plants, eliminating the net-short requirement as a prerequisite for applying the MOPR, eliminating the impact screen, revising the process for reviewing proposed exceptions to the defined minimum sell offer price, and clarifying which resources are subject to the MOPR along with the duration of mitigation. Subsequent FERC Orders revised the MOPR, including clarification on the duration of mitigation, which resources are subject to MOPR, and the MOPR review process.[70]

62 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.

63 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.

64 See PJM. OATT Attachment DD § 6.5.

65 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.

66 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).

67 OATT Attachment DD § 6.8 (b).

68 OATT Attachment DD § 6.8 (a).

69 135 FERC ¶ 61,022 (2011).

70 135 FERC ¶ 61,022 (2011), order on reh'g, 137 FERC ¶ 61,145 (2011).

Effective May 3, 2013, the RPM Minimum Offer Price Rule (MOPR) was changed again.[71] The changes to the MOPR included establishing Competitive Entry and Self Supply Exemptions while also retaining the unit specific exemption process for those that do not qualify for the Competitive Entry or Self Supply Exemptions; changing the applicability of MOPR to include only combustion turbine, combined cycle, integrated gasification combined cycle (IGCC) technologies while excluding units primarily fueled with landfill gas or cogeneration units which are certified or self-certified as Qualifying Facilities (QFs); changing the applicability to increases in installed capacity of 20.0 MW or more combined for all units at a single point of interconnection to the Transmission System; changing the applicability to include the full capability of repowering of plants based on combustion turbine, combined cycle, IGCC technology; increasing the screen from 90 percent to 100 percent of the applicable net CONE values; and broadening the region subject to MOPR to the entire RTO from constrained LDAs only.

2014/2015 RPM Base Residual Auction

As shown in Table 5-13, 1,152 generation resources submitted offers in the 2014/2015 RPM Base Residual Auction. Unit-specific offer caps were calculated for 154 generation resources (13.4 percent of all generation resources offered) including 138 generation resources (12.0 percent) with an Avoidable Project Investment Recovery Rate (APIR) component and three generation resources (0.3 percent) without an APIR component. The MMU calculated offer caps for 709 generation resources (61.5 percent), of which 561 (48.7 percent) were based on the technology specific default (proxy) ACR values. Of the 1,152 generation resources, 22 Planned Generation Capacity Resources had uncapped offers (1.9 percent), 11 generation resources had uncapped planned uprates along with default ACR based offer caps calculated for the existing portion (1.0 percent), six generation resources had uncapped planned uprates along with price taker status for the existing portion (0.5 percent), while the remaining 415 generation resources were price takers (36.0 percent), of which the offers for 413 generation resources were zero and the offers for two generation resources were set to zero because no data were submitted.

Of the 1,152 generation resources which submitted offers, 138 (12.0 percent) included an APIR component. As shown in Table 5-17, the weighted-average gross ACR for resources with APIR ($437.99 per MW-day) and the weighted-average offer caps, net of net revenues, for resources with APIR ($274.45 per MW-day) were higher than for resources without an APIR component, including resources for which the default ACR value was selected. The APIR component added an average of $268.95 per MW-day to the ACR value of the APIR resources. The default ACR values included an average APIR of $1.42 per MW-day, which is the average APIR ($1.37 per MW-day) for the previously estimated default ACR values in the 2013/2014 BRA escalated using the most recent Handy-Whitman Index value. The highest APIR for a technology ($313.37 per MW-day) was for subcritical/supercritical coal units. The maximum APIR effect ($744.80 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

2014/2015 RPM First Incremental Auction

As shown in Table 5-13, 190 generation resources submitted offers in the 2014/2015 RPM First Incremental Auction. Unit-specific offer caps were calculated for 26 generation resources (13.7 percent of all generation resources offered), all of which included an APIR component. The MMU calculated offer caps for 96 generation resources (50.5 percent), of which 71 (37.4 percent) were based on the technology specific default (proxy) ACR values. Of the 190 generation resources, five Planned Generation Capacity Resources had uncapped offers (2.6 percent), 11 generation resources had uncapped planned uprates along with default ACR based offer caps calculated for the existing portion (5.8 percent), four generation resources had uncapped planned uprates along with price taker status for the existing portion (2.1 percent), while the remaining 85 generation resources were price takers (44.7 percent), of which the offers for 85 generation resources were zero and the offers for no generation resources were set to zero because no data were submitted.

2014/2015 RPM Second Incremental Auction

As shown in Table 5-13, 221 generation resources submitted offers in the 2014/2015 RPM Second Incremental Auction. Unit-specific offer caps were calculated for six generation resources (2.7 percent), including five generation resources (2.3 percent) with an

71 143 FERC ¶ 61,090 (2013).

Avoidable Project Investment Recovery Rate (APIR). The MMU calculated offer caps for 72 generation resources (32.6 percent), of which 67 (30.3 percent) were based on the technology specific default (proxy) ACR values. Of the 221 generation resources, five Planned Generation Capacity Resources had uncapped offers (2.3 percent), while the remaining 144 generation resources were price takers (65.2 percent). Market power mitigation was applied to the sell offers for two generation resources.

2014/2015 RPM Third Incremental Auction

As shown in Table 5-13, 404 generation resources submitted offers in the 2014/2015 RPM Third Incremental Auction. Unit-specific offer caps were calculated for 6 generation resources (1.5 percent of all generation resources), of which 6 generation resources included an APIR component. The MMU calculated offer caps for 19 generation resources (4.7 percent), of which 13 were based on the technology specific default (proxy) ACR values. Of the 404 generation resources, three Planned Generation Capacity Resources had uncapped offers (0.7 percent), while the remaining 91 generation resources were price takers (22.5 percent).

2015/2016 RPM Base Residual Auction

As shown in Table 5-14, 1,168 generation resources submitted offers in the 2015/2016 RPM Base Residual Auction. Unit-specific offer caps were calculated for 196 generation resources (16.8 percent) including 171 generation resources (14.6 percent) with an Avoidable Project Investment Recovery Rate (APIR) component and 17 generation resources (1.5 percent) without an APIR component. The MMU calculated offer caps for 670 generation resources (57.4 percent), of which 478 were based on the technology specific default (proxy) ACR values (40.9 percent). Of the 1,168 generation resources, 32 Planned Generation Capacity Resources had uncapped offers (2.7 percent), 25 generation resources (2.1 percent) had uncapped planned uprates along with default ACR based offer caps calculated for the existing portion, seven generation resources (0.6 percent) had uncapped planned uprates along with price taker status for the existing portion, while the remaining 459 generation resources (39.3 percent) were price takers, of which the offers for 458 generation resources were zero and the offer for one generation resources was set to zero because no data were submitted.

Of the 1,168 generation resources which submitted offers, 171 (14.6 percent) included an APIR component. As shown in Table 5-18, the weighted-average gross ACR for resources with APIR ($401.95 per MW-day) and the weighted-average offer caps, net of net revenues, for resources with APIR ($246.63 per MW-day) were higher than for resources without an APIR component, including resources for which the default ACR value was selected. The APIR component added an average of $238.79 per MW-day to the ACR value of the APIR resources. The default ACR values included an average APIR of $1.48 per MW-day, which is the average APIR ($14.42 per MW-day) for the previously estimated default ACR values in the 2014/2015 BRA escalated using the most recent Handy-Whitman Index value. The highest APIR for a technology ($293.45 per MW-day) was for combustion turbine (CT) units. The maximum APIR effect ($776.46 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

2015/2016 RPM First Incremental Auction

As shown in Table 5-14, 131 generation resources submitted offers in the 2015/2016 RPM First Incremental Auction. Unit-specific offer caps were calculated for 20 generation resources (15.3 percent), including 16 generation resources (12.2 percent) with an Avoidable Project Investment Recovery Rate (APIR). The MMU calculated offer caps for 45 generation resources (34.4 percent), of which 25 (19.1 percent) were based on the technology specific default (proxy) ACR values. Of the 221 generation resources, three Planned Generation Capacity Resources had uncapped offers (2.3 percent), one generation resource had an uncapped planned uprate along with a default ACR based offer cap for the existing portion (0.8 percent), while the remaining 83 generation resources were price takers (63.4 percent). Market power mitigation was applied to the sell offer for one generation resource.

2015/2016 RPM Second Incremental Auction

As shown in Table 5-14, 80 generation resources submitted offers in the 2015/2016 RPM Second Incremental Auction. Unit-specific offer caps were calculated for 16 generation resources (20.0 percent of all generation resources), of which 16 generation resources included an APIR component. The MMU calculated offer caps for 25 generation resources (31.3 percent), of which nine were based on the technology specific default (proxy) ACR values (11.3 percent). Of the 80 generation resources, three Planned Generation Capacity Resources had uncapped offers (3.8 percent), while the remaining 52 generation resources were price takers (65.0 percent). Market power mitigation was applied to the sell offers for three generation resources.

2016/2017 RPM Base Residual Auction

As shown in Table 5-15 ACR statistics: 2016/2017 RPM Auctions5-15, 1,199 generation resources submitted offers in the 2016/2017 RPM Base Residual Auction. Unit-specific offer caps were calculated for 152 generation resources (12.7 percent), including 138 generation resources (11.5 percent) with an Avoidable Project Investment Recovery Rate (APIR) and one generation resource (0.1 percent) without an APIR component. The MMU calculated offer caps for 638 generation resources (53.2 percent), of which 491 (41.0 percent) were based on the technology specific default (proxy) ACR values. Of the 1,199 generation resources, 31 Planned Generation Capacity Resources had uncapped offers (2.6 percent), 15 generation resources had uncapped planned uprates along with default ACR based offer caps calculated for the existing portion (1.3 percent), and 11 generation resources had uncapped planned uprates along with price taker status for the existing portion (0.9 percent), while the remaining 519 generation resources were price takers (43.3 percent). Market power mitigation was applied to the sell offers for 50 generation resources.

Of the 1,199 generation resources which submitted offers, 138 (11.5 percent) included an APIR component. As shown in Table 5-19 APIR statistics: 2016/2017 RPM Base Residual Auction5-19, the weighted average gross ACR for units with APIR ($352.84 per MW-day) and the weighted-average offer caps, net of net revenues, for units with APIR ($180.23 per MW-day) decreased from the 2015/2016 BRA values of $401.95 per MW-day and $246.63 per MW-day, due primarily to lower weighted average gross ACRs for combined cycle, combustion turbine, oil and gas steam units, and subcritical/supercritical coal units. The APIR component added an average of $191.19 per MW-day to the ACR value of the APIR units compared to $238.79 per MW-day in the 2015/2016 BRA. The highest APIR for a technology ($236.99 per MW-day) was for subcritical/supercritical coal units. The maximum APIR effect ($773.08 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

2016/2017 RPM First Incremental Auction

As shown in Table 5-15, 115 generation resources submitted offers in the 2016/2017 RPM First Incremental Auction. Unit-specific offer caps were calculated for 37 generation resources (32.2 percent of all generation resources), of which 32 generation resources (27.8 percent) included an APIR component. The MMU calculated offer caps for 62 generation resources (53.9 percent), of which 25 were based on the technology specific default (proxy) ACR values (21.7 percent). Of the 115 generation resources, one Planned Generation Capacity Resources had uncapped offers (0.9 percent), while the remaining 52 generation resources were price takers (45.2 percent). Market power mitigation was applied to the sell offers for four generation resources.

2017/2018 RPM Base Residual Auction

As shown in Table 5-16, 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 (10.1 percent) 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 (33.3 percent). Of the 1,202 generation resources, 28 Planned Generation Capacity Resources had uncapped offers (2.3 percent), while the remaining 637 generation resources were price takers (53.0 percent).

Of the 1,202 generation resources which submitted offers, 122 (10.1 percent) included an APIR component. As shown in Table 5-20, the weighted average gross ACR for units with APIR ($413.87 per MW-day) and the weighted-average offer caps, net of net revenues, for units with APIR ($256.02 per MW-day) increased from the 2016/2017 BRA values of $352.84 per MW-day and $180.23 per MW-day, due to higher weighted average gross ACRs for combined cycle, combustion turbine, subcritical/supercritical coal, and other units. The APIR component added an average of $217.84 per MW-day to the ACR value of the APIR units compared to $191.19 per MW-day in the 2016/2017 BRA. The highest APIR for a technology ($281.82 per MW-day) was for subcritical/supercritical coal units. The maximum APIR effect ($863.76 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

Table 5-13 ACR statistics: 2014/2015 RPM Auctions

	2014/2015 Base Residual Auction		2014/2015 First Incremental Auction		2014/2015 Second Incremental Auction		2014/2015 Third Incremental Auction	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	544	47.2%	59	31.1%	66	29.9%	13	3.2%
ACR data input (APIR)	138	12.0%	21	11.1%	5	2.3%	6	1.5%
ACR data input (non-APIR)	3	0.3%	0	0.0%	0	0.0%	0	0.0%
Opportunity cost input	7	0.6%	4	2.1%	0	0.0%	0	0.0%
Default ACR and opportunity cost	6	0.5%	1	0.5%	1	0.5%	0	0.0%
Offer cap of 1.1 times BRA clearing price elected	NA	NA	NA	NA	NA	NA	291	72.0%
Uncapped planned uprate and default ACR	11	1.0%	11	5.8%	0	0.0%	0	0.0%
Uncapped planned uprate and opportunity cost	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Uncapped planned uprate and price taker	6	0.5%	4	2.1%	0	0.0%	0	0.0%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	NA	NA	NA	NA	0	0.0%
Uncapped planned generation resources	22	1.9%	5	2.6%	5	2.3%	3	0.7%
Price takers	415	36.0%	85	44.7%	144	65.2%	91	22.5%
Total Generation Capacity Resources offered	1,152	100.0%	190	100.0%	221	100.0%	404	100.0%

Table 5-14 ACR statistics: 2015/2016 RPM Auctions

	2015/2016 Base Residual Auction		2015/2016 First Incremental Auction		2015/2016 Second Incremental Auction	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	449	38.4%	24	18.3%	9	11.3%
ACR data input (APIR)	171	14.6%	16	12.2%	16	20.0%
ACR data input (non-APIR)	17	1.5%	0	0.0%	0	0.0%
Opportunity cost input	4	0.3%	4	3.1%	0	0.0%
Default ACR and opportunity cost	4	0.3%	0	0.0%	0	0.0%
Offer cap of 1.1 times BRA clearing price elected	NA	NA	NA	NA	NA	NA
Uncapped planned uprate and default ACR	25	2.1%	1	0.8%	0	0.0%
Uncapped planned uprate and opportunity cost	0	0.0%	0	0.0%	0	0.0%
Uncapped planned uprate and price taker	7	0.6%	0	0.0%	0	0.0%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	NA	NA	NA	NA
Uncapped planned generation resources	32	2.7%	3	2.3%	3	3.8%
Price takers	459	39.3%	83	63.4%	52	65.0%
Total Generation Capacity Resources offered	1,168	100.0%	131	100.0%	80	100.0%

Table 5-15 ACR statistics: 2016/2017 RPM Auctions

	2016/2017 Base Residual Auction		2016/2017 First Incremental Auction	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	471	39.3%	24	20.9%
ACR data input (APIR)	138	11.5%	32	27.8%
ACR data input (non-APIR)	1	0.1%	4	3.5%
Opportunity cost input	8	0.7%	1	0.9%
Default ACR and opportunity cost	5	0.4%	0	0.0%
Offer cap of 1.1 times BRA clearing price elected	NA	NA	NA	NA
Uncapped planned uprate and default ACR	15	1.3%	1	0.9%
Uncapped planned uprate and opportunity cost	0	0.0%	0	0.0%
Uncapped planned uprate and price taker	11	0.9%	0	0.0%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	NA	NA
Uncapped planned generation resources	31	2.6%	1	0.9%
Price takers	519	43.3%	52	45.2%
Total Generation Capacity Resources offered	1,199	100.0%	115	100.0%

Table 5-16 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%

Table 5-17 APIR statistics: 2014/2015 RPM Base Residual Auction

	Weighted-Average ($ per MW-day UCAP)					
	Combined Cycle	Combustion Turbine	Oil or Gas Steam	Subcritical/Supercritical Coal	Other	Total
Non-APIR units						
ACR	$47.04	$34.61	$84.19	$222.70	$58.86	$110.52
Net revenues	$112.21	$29.80	$14.52	$306.01	$226.46	$152.35
Offer caps	$8.92	$16.34	$74.66	$28.52	$16.68	$25.32
APIR units						
ACR	NA	$65.34	$278.46	$511.79	$330.13	$437.99
Net revenues	NA	$18.24	$55.97	$222.06	$138.36	$182.98
Offer caps	NA	$51.46	$222.49	$313.68	$191.78	$274.45
APIR	NA	$38.99	$185.24	$313.37	$1.67	$268.95
Maximum APIR effect						$744.80

Table 5-18 APIR statistics: 2015/2016 RPM Base Residual Auction

	Weighted-Average ($ per MW-day UCAP)					
	Combined Cycle	Combustion Turbine	Oil or Gas Steam	Subcritical/ Supercritical Coal	Other	Total
Non-APIR units						
ACR	$50.33	$36.07	$85.46	$232.16	$81.94	$113.51
Net revenues	$160.85	$34.32	$35.86	$248.90	$265.61	$148.07
Offer caps	$5.89	$11.34	$49.70	$26.50	$7.73	$17.86
APIR units						
ACR	$163.25	$334.57	$192.87	$471.60	$41.74	$401.95
Net revenues	$8.33	$17.93	$17.39	$221.10	$57.91	$166.81
Offer caps	$154.94	$316.69	$175.53	$264.18	$8.15	$246.63
APIR	$116.55	$293.45	$87.42	$265.13	$23.35	$238.79
Maximum APIR effect						$776.46

Table 5-19 APIR statistics: 2016/2017 RPM Base Residual Auction

	Weighted-Average ($ per MW-day UCAP)					
	Combined Cycle	Combustion Turbine	Oil or Gas Steam	Subcritical/ Supercritical Coal	Other	Total
Non-APIR units						
ACR	$42.11	$33.46	$78.32	$215.57	$75.69	$102.23
Net revenues	$194.19	$56.23	$42.33	$208.04	$228.59	$150.24
Offer caps	$4.80	$7.64	$36.43	$29.03	$4.63	$16.07
APIR units						
ACR	$52.48	$93.23	$188.80	$432.72	$53.20	$352.84
Net revenues	$72.50	$17.49	$16.68	$222.52	$62.15	$177.14
Offer caps	$13.92	$79.12	$167.29	$213.88	$5.91	$180.23
APIR	$14.45	$57.71	$64.90	$236.99	$23.01	$191.19
Maximum APIR effect						$773.08

Table 5-20 APIR statistics: 2017/2018 RPM Base Residual Auction[72]

	Weighted-Average ($ per MW-day UCAP)					
	Combined Cycle	Combustion Turbine	Oil or Gas Steam	Subcritical/ Supercritical Coal	Other	Total
Non-APIR units						
ACR	$36.92	$31.52	$84.84	$182.60	$47.54	$94.78
Net revenues	$121.99	$51.56	$13.98	$116.61	$158.64	$92.26
Offer caps	$2.17	$9.90	$71.43	$70.61	$8.28	$36.87
APIR units						
ACR	$136.06	$97.45	$180.36	$440.80	$554.65	$413.87
Net revenues	$0.00	$1.84	$42.70	$92.18	$382.31	$137.71
Offer caps	$136.06	$95.61	$137.66	$319.61	$163.77	$256.02
APIR	$95.80	$55.48	$92.23	$281.82	$128.37	$217.84
Maximum APIR effect						$863.76

Market Performance[73]

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 5-21 Capacity prices: 2007/2008 through 2017/2018 RPM Auctions5-21shows RPM clearing prices for all RPM Auctions held through 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 2014. In the 2014/2015 Delivery Year, the lowest weighted average price was $117.42 in the rest of RTO, and the highest weighted average price was $232.47 in PSEG North. For the 2015/2016 Delivery Year, the lowest weighted average price is $133.51 in the rest of RTO, and the highest weighted average price is $335.21 in ATSI. For the 2016/2017 Delivery Year, the lowest weighted average price is $59.38 in the rest of RTO, and the highest weighted average price is $222.43 PSEG. For the 2017/2018 Delivery Year, the lowest weighted average price is $118.35 in PPL and the highest weighted average price is $214.77 in PSEG North.

Table 5-22 shows RPM revenue by resource type for all RPM Auctions held through 2014 with $3.1 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 5-23 shows RPM revenue by calendar year for all RPM Auctions held through 2014. In 2014, RPM revenue totaled approximately $7.2 billion.

72 Effective for the 2017/2018 and subsequent Delivery Years, the ACR technology classes of waste coal small and large were eliminated and combined with subcritical and supercritical coal to form the Coal Fired ACR technology class. Waste coal resources were included in the other category in prior versions of this table. For the 2017/2018 BRA, waste coal resources were included in the coal fired category.

73 The MMU provides detailed analyses of market performance in reports for each RPM Auction. See <http://www.monitoringanalytics.com/reports/Reports/2014.shtml>.

Table 5-24 shows the RPM annual charges to load. For the 2014/2015 Delivery Year, RPM annual charges to load total approximately $7.3 billion.

Table 5-21 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
2015/2016 Second Incremental Auction	Limited	$123.56	$141.12	$123.56	$141.12	$141.12	$141.12	$141.12	$155.02	$155.02	$141.12	$204.10
2015/2016 Second Incremental Auction	Extended Summer	$136.00	$153.56	$136.00	$153.56	$153.56	$153.56	$153.56	$167.46	$167.46	$153.56	$216.54
2015/2016 Second Incremental Auction	Annual	$136.00	$153.56	$136.00	$153.56	$153.56	$153.56	$153.56	$167.46	$167.46	$153.56	$216.54
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
2016/2017 First Incremental Auction	Limited	$53.93	$89.35	$53.93	$89.35	$89.35	$89.35	$89.35	$214.44	$214.44	$89.35	$94.45
2016/2017 First Incremental Auction	Extended Summer	$60.00	$119.13	$60.00	$119.13	$119.13	$119.13	$119.13	$244.22	$244.22	$119.13	$100.52
2016/2017 First Incremental Auction	Annual	$60.00	$119.13	$60.00	$119.13	$119.13	$119.13	$119.13	$244.22	$244.22	$119.13	$100.52
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

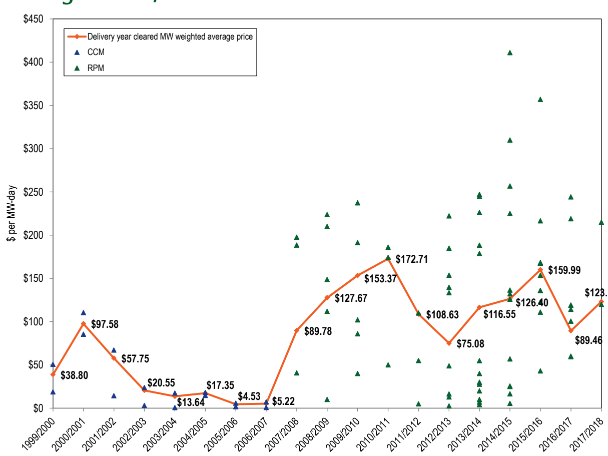
Table 5-22 RPM revenue by type: 2007/2008 through 2017/2018[74 75]

				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	$1,474,196,391	$3,472,667	$209,490,444	$0	$996,085,233	$0	$486,964,987	$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	$1,921,777,216	$9,751,112	$287,850,403	$0	$1,322,601,837	$0	$560,831,808	$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	$2,290,125,059	$30,168,831	$364,742,517	$0	$1,517,723,628	$0	$700,939,675	$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	$2,599,694,869	$58,065,964	$442,429,815	$0	$1,799,258,125	$0	$655,782,363	$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	$1,615,369,731	$98,448,693	$278,529,660	$0	$1,079,386,338	$0	$360,032,004	$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	$1,088,456,008	$76,633,409	$179,117,975	$11,397	$762,719,550	$0	$414,915,199	$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	$1,869,087,820	$167,844,235	$308,853,673	$25,708	$1,346,223,419	$0	$668,652,167	$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	$2,009,249,240	$205,555,569	$333,941,614	$6,649,774	$1,464,950,862	$0	$476,813,839	$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	$894,128,738	$55,975,130	$206,230,276	$2,835,489,278	$63,675,945	$2,493,249,821	$530,431,461	$387,351,989	$15,472,171	$1,849,884,449	$0	$556,911,713	$7,256,033	$0	$4,902,514	$35,605,323	$6,079,637	$1,829,269	$41,406,297	$9,985,880,044
2016/2017	$444,241,430	$37,315,013	$161,388,134	$1,326,359,035	$42,543,693	$1,506,445,844	$502,578,551	$221,710,215	$10,367,343	$1,002,896,452	$0	$336,730,453	$5,613,584	$0	$5,308,879	$28,371,993	$4,125,154	$1,144,873	$21,665,899	$5,658,806,545
2017/2018	$476,896,058	$59,254,100	$189,649,620	$1,839,412,938	$56,002,680	$2,083,473,655	$860,951,050	$312,755,908	$15,124,140	$1,155,829,440	$0	$380,100,780	$5,479,380	$0	$6,440,243	$30,737,198	$5,752,583	$1,292,100	$33,077,760	$7,512,229,630

Table 5-23 RPM revenue by calendar year: 2007 through 2018[76]

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	$146.09	167,196.5	365	$8,915,526,042
2016	$118.75	171,750.5	366	$7,464,907,468
2017	$109.24	169,177.5	365	$6,745,471,039
2018	$123.19	167,068.9	151	$3,107,799,107

Figure 5-4 History of PJM capacity prices: 1999/2000 through 2017/2018[77]



74 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.

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

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

77 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.

Table 5-24 RPM cost to load: 2013/2014 through 2017/2018 RPM Auctions[78 79 80]

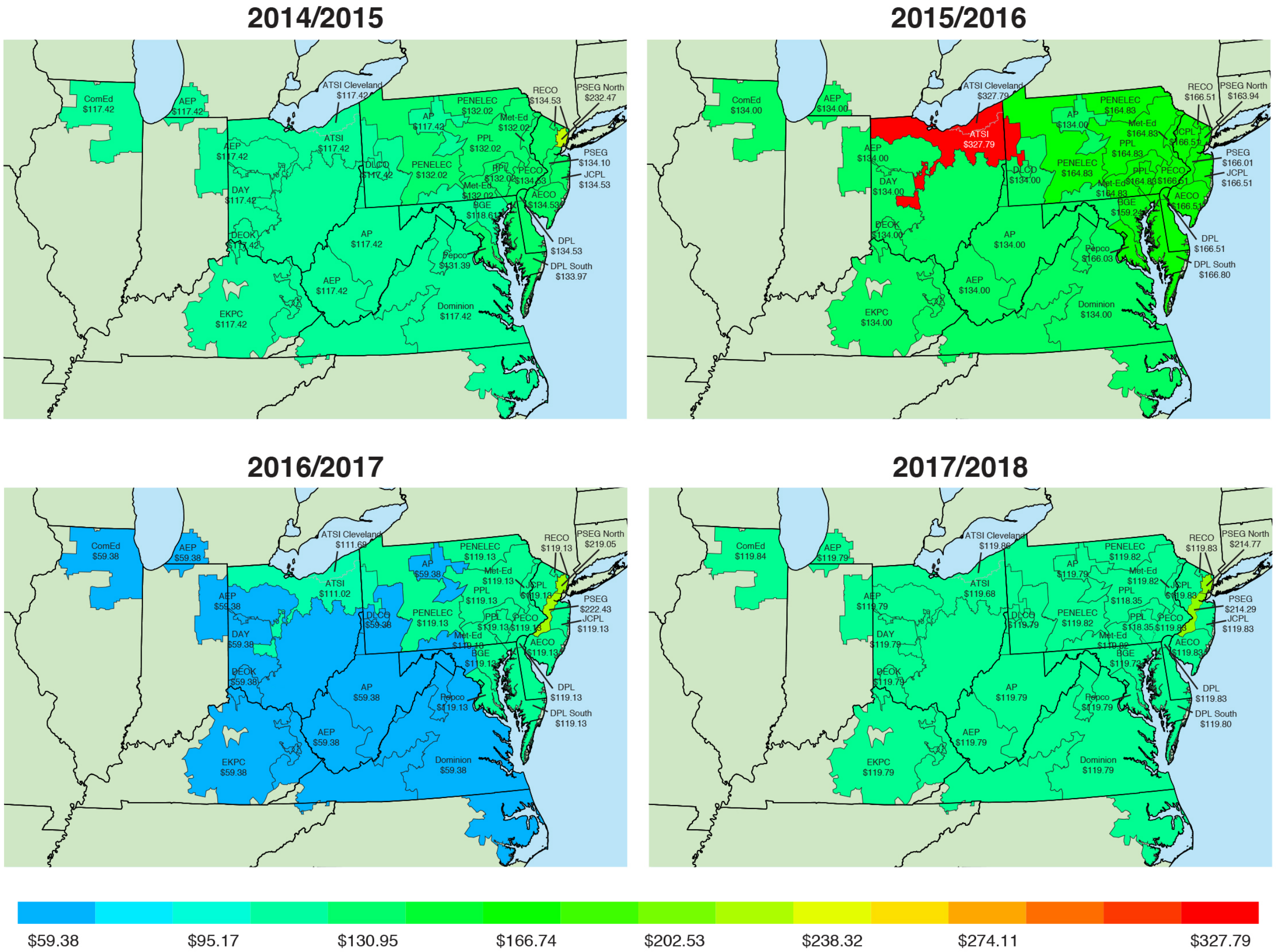
	Net Load Price ($ per MW-day)	UCAP Obligation (MW)	Annual Charges
2013/2014			
Rest of RTO	$28.45	80,012.1	$830,802,258
Rest of MAAC	$232.55	14,623.8	$1,241,276,219
EMAAC	$248.30	36,094.7	$3,271,227,460
Rest of SWMAAC	$231.58	7,925.5	$669,900,300
Pepco	$244.94	7,525.2	$672,777,842
Total		146,181.3	$6,685,984,079
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	$135.79	82,638.6	$4,107,095,920
Rest of MAAC	$166.41	55,375.9	$3,372,664,490
PSEG	$166.16	11,661.2	$709,176,272
ATSI	$296.45	14,598.2	$1,583,895,942
Total		164,273.8	$9,772,832,625
2016/2017			
Rest of RTO	$59.38	87,663.9	$1,900,087,197
Rest of MAAC	$118.73	56,662.4	$2,455,596,495
PSEG	$177.05	11,886.2	$768,108,919
ATSI	$90.82	14,850.8	$492,276,789
Total		171,063.3	$5,616,069,400
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

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

79 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.

80 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.

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



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).[81]

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 2014, nuclear units had a capacity factor of 94.2 percent, compared to 93.8 percent in 2013. Combined cycle units ran more often, increasing from a capacity factor of 51.6 percent in 2013 to 54.9 percent in 2014. The capacity factor for steam units, which are primarily coal fired, increased from 49.5 percent in 2013 to 50.2 percent in 2014.

81 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.

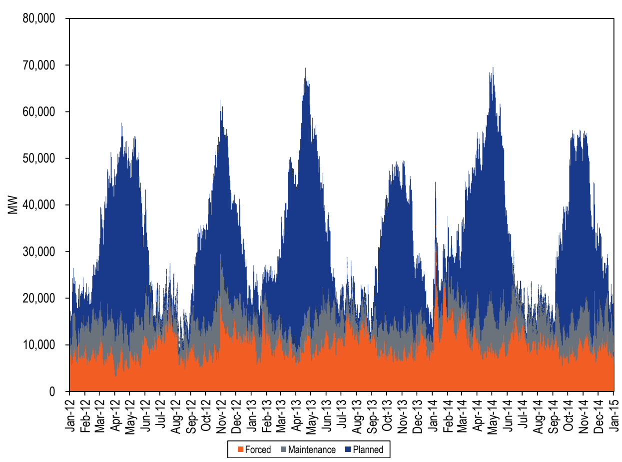
Table 5-25 PJM capacity factor (By unit type (GWh)): January through December of 2013 and 2014[82] [83]

	2013		2014	
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor
Combined Cycle	119,414.7	51.6%	122,699.6	54.9%
Combustion Turbine	7,722.7	2.9%	9,621.3	3.6%
Diesel	613.2	16.4%	280.7	9.5%
Diesel (Landfill gas)	1,380.9	43.5%	1,399.5	58.2%
Fuel Cell	115.3	43.9%	222.7	84.7%
Nuclear	277,277.8	93.8%	277,635.6	94.2%
Pumped Storage Hydro	6,716.2	14.0%	5,673.3	14.4%
Run of River Hydro	7,368.8	34.0%	5,532.9	30.8%
Solar	355.0	15.8%	325.7	15.8%
Steam	361,307.3	49.5%	349,959.2	50.2%
Wind	14,826.9	26.8%	14,590.9	28.7%
Total	797,099.6	48.0%	787,941.4	49.3%

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."

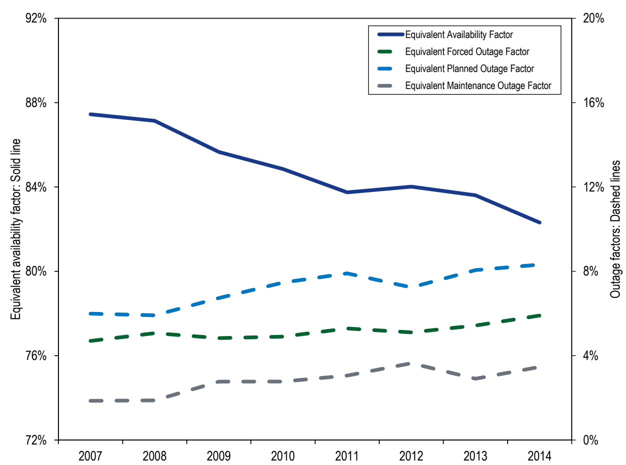
Figure 5-6 PJM outages (MW): 2012 through 2014



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

The PJM aggregate EAF for 2014 was 82.3 percent, a decrease from 83.6 percent for 2013. The PJM aggregate EAF, EFOF, EPOF, and EMOF are shown in Figure 5-7. Metrics by unit type are shown in Table 5-26 through Table 5-29.

Figure 5-7 PJM equivalent outage and availability factors: 2007 to 2014



82 The EKPC Transmission Zone was integrated on June 1, 2013 and is not included in the numbers for the first five months of 2013.

83 The capacity factor for wind and solar unit types in this table are based on nameplate capacity values, and are calculated based on when the units come on line.

Table 5-26 EAF by unit type: 2007 through 2014

	2007	2008	2009	2010	2011	2012	2013	2014
Combined Cycle	91.2%	91.5%	87.9%	86.0%	85.6%	85.5%	86.1%	84.6%
Combustion Turbine	91.1%	91.7%	93.2%	93.1%	91.8%	92.4%	89.1%	88.4%
Diesel	86.5%	87.8%	91.7%	93.9%	94.9%	93.1%	92.5%	83.3%
Hydroelectric	91.8%	89.9%	86.8%	88.8%	84.6%	88.8%	87.9%	85.7%
Nuclear	94.7%	93.3%	90.1%	91.8%	90.1%	91.1%	92.2%	91.5%
Steam	82.2%	82.1%	81.0%	79.0%	78.3%	77.9%	77.2%	75.4%
Total	87.4%	87.1%	85.7%	84.9%	83.7%	84.0%	83.6%	82.3%

Table 5-27 EMOF by unit type: 2007 through 2014

	2007	2008	2009	2010	2011	2012	2013	2014
Combined Cycle	1.7%	1.4%	3.1%	3.0%	2.4%	2.7%	2.6%	2.4%
Combustion Turbine	2.1%	2.0%	2.3%	2.0%	2.4%	1.7%	1.9%	1.9%
Diesel	1.8%	1.2%	1.1%	1.5%	1.9%	2.4%	1.4%	2.3%
Hydroelectric	1.6%	1.7%	2.3%	1.9%	1.9%	2.1%	1.9%	2.8%
Nuclear	0.3%	0.6%	0.6%	0.5%	1.2%	1.1%	0.7%	0.9%
Steam	2.5%	2.5%	3.7%	3.9%	4.2%	5.6%	4.3%	5.5%
Total	1.9%	1.9%	2.8%	2.8%	3.1%	3.6%	2.9%	3.5%

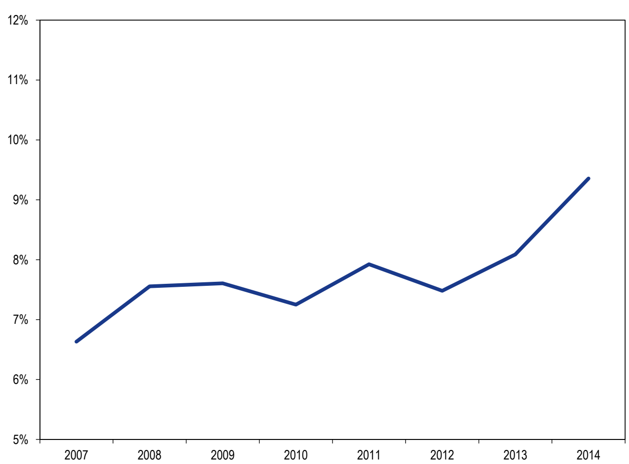
Table 5-28 EPOF by unit type: 2007 through 2014

	2007	2008	2009	2010	2011	2012	2013	2014
Combined Cycle	5.1%	5.0%	6.3%	8.5%	9.5%	8.3%	8.8%	10.4%
Combustion Turbine	2.1%	3.5%	2.8%	3.0%	3.8%	3.2%	4.0%	3.9%
Diesel	0.7%	1.2%	0.6%	0.5%	0.1%	0.7%	0.3%	0.4%
Hydroelectric	5.4%	6.8%	8.7%	8.6%	11.8%	6.3%	7.8%	9.0%
Nuclear	3.8%	5.2%	5.2%	5.4%	6.1%	6.4%	5.9%	5.8%
Steam	8.4%	7.1%	8.5%	9.3%	9.2%	8.7%	10.2%	10.3%
Total	6.0%	5.9%	6.7%	7.5%	7.9%	7.2%	8.1%	8.3%

Table 5-29 EFOF by unit type: 2007 through 2014

	2007	2008	2009	2010	2011	2012	2013	2014
Combined Cycle	2.1%	2.1%	2.7%	2.6%	2.5%	3.5%	2.5%	2.6%
Combustion Turbine	4.6%	2.8%	1.7%	1.9%	2.0%	2.8%	5.0%	5.9%
Diesel	10.9%	9.9%	6.6%	4.2%	3.1%	3.8%	5.9%	14.0%
Hydroelectric	1.3%	1.6%	2.3%	0.7%	1.7%	2.8%	2.3%	2.4%
Nuclear	1.1%	0.9%	4.1%	2.3%	2.6%	1.5%	1.1%	1.8%
Steam	7.0%	8.3%	6.8%	7.7%	8.3%	7.8%	8.3%	8.8%
Total	4.7%	5.1%	4.8%	4.9%	5.3%	5.1%	5.4%	5.9%

Figure 5-8 Trends in the PJM equivalent demand forced outage rate (EFORd): 2007 through 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.84 The EFORd metric includes all forced outages, regardless of the reason for those outages.

The average PJM EFORd for 2014 was 9.4 percent, an increase from the 8.1 percent average PJM EFORd for 2013. Figure 5-8 shows the average EFORd since 2007 for all units in PJM.

Table 5-30 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 2014.

84 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.

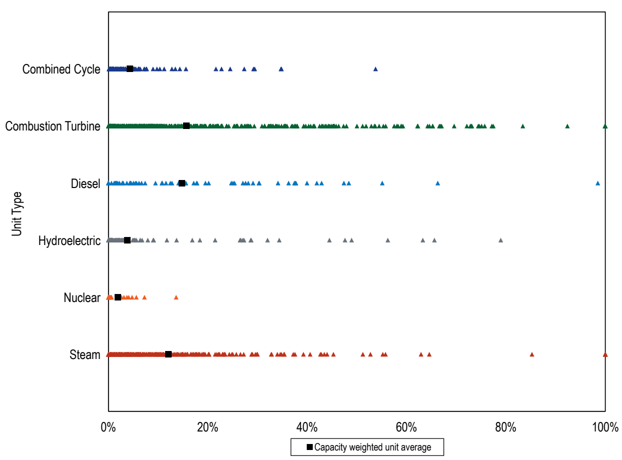
Table 5-30 PJM EFORd data for different unit types: 2007 through 2014

	2007	2008	2009	2010	2011	2012	2013	2014
Combined Cycle	3.5%	3.4%	4.1%	3.8%	3.4%	4.2%	3.2%	4.3%
Combustion Turbine	10.6%	10.7%	9.8%	8.9%	8.0%	8.2%	10.7%	15.6%
Diesel	12.5%	11.0%	9.3%	6.1%	9.2%	5.1%	6.5%	14.8%
Hydroelectric	1.9%	2.5%	3.2%	1.2%	2.9%	4.4%	3.7%	3.8%
Nuclear	1.2%	1.0%	4.1%	2.5%	2.8%	1.6%	1.2%	1.9%
Steam	8.6%	10.4%	9.3%	9.8%	11.2%	10.6%	11.6%	12.1%
Total	6.6%	7.6%	7.6%	7.2%	7.9%	7.5%	8.1%	9.4%

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 2014.

Figure 5-9 PJM distribution of EFORd data by unit type



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).[85] 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.[86] 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.[87] That choice was made by PJM and can be modified without violating any NERC requirements.[88] 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.

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 5-31 shows OMC forced outages by cause code, as classified by PJM. OMC forced outages accounted for 7.7 percent of all forced outages in 2014. The largest contributor to OMC outages, flood, was the cause of 37.1 percent of OMC outages and 2.9 percent of all forced outages.

85 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*>.

86 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*>.

87 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.

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

Table 5-31 OMC Outages

OMC Cause Code	Percent of OMC Forced Outages	Percent of all Forced Outages
Flood	37.1%	2.9%
Hurricane	17.4%	1.3%
Other switchyard equipment	14.7%	1.1%
Transmission system problems other than catastrophes	9.6%	0.7%
Lack of fuel	6.8%	0.5%
Lightning	4.1%	0.3%
Transmission line	2.9%	0.2%
Switchyard transformers and associated cooling systems	1.5%	0.1%
Other miscellaneous external problems	1.4%	0.1%
Transmission equipment beyond the first substation	1.1%	0.1%
Switchyard circuit breakers	0.9%	0.1%
High sulfur content	0.8%	0.1%
Lack of water	0.7%	0.1%
Storms	0.4%	0.0%
Fire	0.2%	0.0%
Plant modifications	0.2%	0.0%
Switchyard system protection devices	0.1%	0.0%
Transmission equipment at the first substation	0.1%	0.0%
Other fuel quality problems	0.0%	0.0%
Tornado	0.0%	0.0%
Total	100.0%	7.7%

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.

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.[89]

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.

89 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).

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.[90] 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

The Peak-Hour Period Availability Charge is equal to the seller's weighted average resource clearing price for the delivery year for the LDA.[91]

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,[92] 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.[93]

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.[94]

There is a separate exception to the performance related incentives related to lack of gas during the winter period.

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

91 PJM. OATT Attachment DD § 10 (j).
92 PJM. "Manual 18: PJM Capacity Market," Revision 15 (June 28, 2012), p. 159
93 PJM. "Manual 18: PJM Capacity Market," Revision 15 (June 28, 2012), Section 8.4.5.
94 PJM. "Manual 18: PJM Capacity Market," Revision 15 (June 28, 2012), Section 8.4.5.1.

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.[95] The result is an exception, analogous to the lack of fuel exception, except much broader, which appears to have no logical basis.

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.[96]

There is a separate exception for wind and solar capacity resources which are exempt from this performance incentive.[97]

The peak hour availability charge does not apply if the unit unavailability resulted in another performance related charge or penalty.[98]

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.[99]

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.[100] On a systemwide basis, the resultant lost equivalent availability from the forced outages is equal to the equivalent forced outage factor.[101]

PJM EFOF was 5.9 percent in 2014. This means there was 5.9 percent lost availability because of forced outages. Table 5-32 shows that forced outages for boiler tube leaks, at 20.4 percent of the systemwide EFOF, were the largest single contributor to EFOF.

95 PJM. OATT Attachment DD § 7.10 (e).
96 PJM. OATT Attachment DD § 7.10 (e).
97 PJM. OATT Attachment DD § 7.10 (e).
98 PJM. OATT Attachment DD § 7.10 (e).
99 PJM. "Manual 18: PJM Capacity Market," Revision 15 (June 28, 2012) p. 98.
100 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.
101 EFOF incorporates all outages regardless of their designation as OMC.

Table 5-32 Contribution to EFOF by unit type by cause: 201

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	System
Boiler Tube Leaks	3.4%	0.0%	0.0%	0.0%	0.0%	28.8%	20.4%
Economic	8.2%	31.7%	2.3%	2.9%	0.0%	3.9%	8.4%
Electrical	1.6%	10.0%	5.4%	3.4%	14.2%	5.1%	6.2%
Boiler Air and Gas Systems	0.0%	0.0%	0.0%	0.0%	0.0%	7.8%	5.5%
Catastrophe	0.4%	26.3%	2.7%	15.6%	0.0%	0.0%	4.6%
Boiler Piping System	3.9%	0.0%	0.0%	0.0%	0.0%	4.5%	3.4%
Reserve Shutdown	5.2%	6.0%	9.8%	14.7%	4.5%	2.0%	3.3%
Boiler Fuel Supply from Bunkers to Boiler	0.2%	0.0%	0.0%	0.0%	0.0%	4.5%	3.2%
Feedwater System	2.5%	0.0%	0.0%	0.0%	2.7%	3.1%	2.5%
Precipitators	0.0%	0.0%	0.0%	0.0%	0.0%	3.6%	2.5%
Generator	16.3%	0.1%	3.7%	0.7%	1.3%	1.6%	2.2%
Miscellaneous (Boiler)	0.0%	0.0%	0.0%	0.0%	0.0%	3.0%	2.1%
Controls	5.1%	0.2%	0.2%	0.3%	5.3%	1.9%	2.0%
Miscellaneous (Balance of Plant)	1.6%	1.3%	0.0%	0.1%	3.2%	2.0%	1.9%
Miscellaneous (Generator)	10.2%	1.9%	45.1%	11.5%	0.0%	0.7%	1.9%
Fuel Quality	0.0%	0.1%	2.4%	0.0%	0.0%	2.3%	1.6%
Reactor Coolant System	0.0%	0.0%	0.0%	0.0%	28.9%	0.0%	1.6%
Exciter	0.4%	0.4%	0.3%	5.6%	0.0%	1.8%	1.5%
Condensing System	1.0%	0.0%	0.0%	0.0%	1.2%	1.9%	1.5%
All Other Causes	40.1%	22.1%	28.2%	45.2%	38.6%	21.4%	24.1%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Table 5-33 shows the categories which are included in the economic category.[102] Lack of fuel that is considered outside management control accounted for 6.3 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."[103] 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 5-33 Contributions to Economic Outages: 2014

	Contribution to Economic Reasons
Lack of fuel (Non-OMC)	84.5%
Other economic problems	6.3%
Lack of fuel (OMC)	6.3%
Fuel conservation	1.8%
Lack of water	0.6%
Problems with primary fuel for units with secondary fuel operation	0.4%
Ground water or other water supply problems	0.1%
Total	100.0%

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.[104] 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

102 The definitions of these outages are defined by NERC GADS.
103 The definitions of these outages are defined by NERC GADS.

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

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 5-34 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.

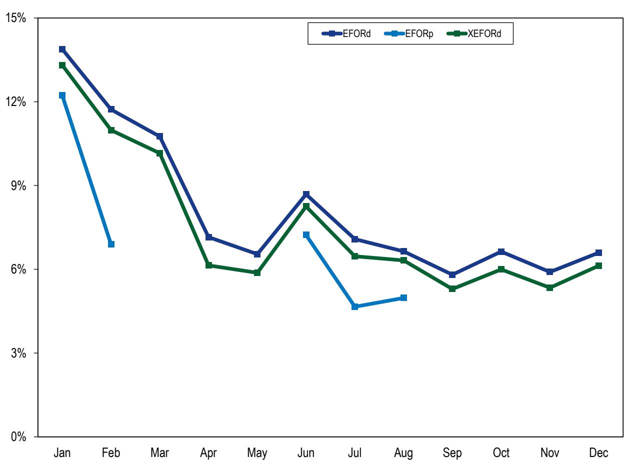
Table 5-34 PJM EFORd, XEFORd and EFORp data by unit type[105]

	EFORd	XEFORd	EFORp	Difference EFORd and XEFORd	Difference EFORd and EFORp
Combined Cycle	4.3%	4.1%	2.8%	0.2%	1.5%
Combustion Turbine	15.6%	13.1%	12.2%	2.5%	3.4%
Diesel	14.8%	14.6%	5.4%	0.2%	9.4%
Hydroelectric	3.8%	2.5%	1.3%	1.2%	2.5%
Nuclear	1.9%	1.9%	2.7%	0.1%	(0.8%)
Steam	12.1%	11.9%	10.1%	0.1%	2.0%
Total	9.4%	8.8%	7.7%	0.6%	1.6%

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: 2014



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

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

Figure 5-11 PJM monthly generator performance factors: 2014