Capacity Market

Each organization serving PJM load must meet its capacity obligations through the PJM Capacity Market, where load serving entities (LSEs) must pay the locational capacity price for their zone. LSEs can also construct generation and offer it into the capacity market, enter into bilateral contracts, develop demand-side resources and Energy Efficiency (EE) resources and offer them into the capacity market, or construct transmission upgrades and offer them into the capacity market.

The Market Monitoring Unit (MMU) analyzed market structure, participant conduct and market performance in the PJM Capacity Market for 2012, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.[1]

Table 4-1 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. The entire PJM region failed the preliminary market structure screen (PMSS), which is conducted by the MMU prior to each Base Residual Auction (BRA), for every planning year for which a BRA has been run to date. 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. All modeled Locational Deliverability Areas (LDAs) failed the PMSS, which is conducted by the MMU prior to each Base Residual Auction, for every planning year for which a BRA has been run to date. For almost every auction held, all LDAs have failed the TPS test, which is conducted at the time of the auction.[3]
- Participant behavior was evaluated as competitive. Market power mitigation measures were applied when the Capacity Market Seller failed the market power test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price. Market power mitigation rules were also applied when the Capacity Market Seller submitted a sell offer for a new resource or uprate that was below the Minimum Offer Price Rule (MOPR) threshold.
- Market performance was evaluated as competitive. Although structural market power exists in the Capacity Market, a competitive outcome resulted from the application of market power mitigation rules.
- Market design was evaluated as mixed because while there are many positive features of the Reliability Pricing Model (RPM) design, there are several features of the RPM design which threaten competitive outcomes. These include the 2.5 percent reduction in demand in Base Residual Auctions and the definition of DR which permits inferior products to substitute for capacity.

Overview

RPM Capacity Market

Market Design

The Reliability Pricing Model (RPM) Capacity Market is a forward-looking, annual, locational market, with a must offer requirement for Existing Generation Capacity Resources and mandatory participation by load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand-side resources.[4]

Under RPM, capacity obligations are annual. Base Residual Auctions (BRA) are held for delivery years that are three years in the future. Effective with the 2012/2013 Delivery Year, First, Second and Third Incremental Auctions (IA) are held for each delivery year.[5] Prior to the 2012/2013 Delivery Year, the Second Incremental Auction was conducted if PJM determined that an unforced capacity resource shortage exceeded

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 *2011 State of the Market Report for PJM*, Section 4, "Capacity Market" and include all capacity within the PJM footprint.

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

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] Previously, First, Second, and Third Incremental Auctions were conducted 23, 13 and four months, prior to the delivery year. Also effective for the 2012/2013 Delivery Year, a conditional incremental auction may be held if there is a need to procure additional capacity resulting from a delay in a planned large transmission upgrade that was modeled in the BRA for the relevant delivery year.[7]

RPM prices are locational and may vary depending on transmission constraints.[8] Existing generation capable of qualifying as a capacity resource must be offered into RPM Auctions, except for resources owned by entities that elect the fixed resource requirement (FRR) option. Participation by LSEs is mandatory, except for those entities that elect the FRR option. There is an administratively determined demand curve that defines scarcity pricing levels and that, with the supply curve derived from capacity offers, determines market prices in each BRA. RPM rules provide performance incentives for generation, including the requirement to submit generator outage data and the linking of capacity payments to the level of unforced capacity. Under RPM there are explicit market power mitigation rules that define the must offer requirement, that define structural market power, that define offer caps based on the marginal cost of capacity, that define the minimum offer price, and that have flexible criteria for competitive offers by new entrants. Demand-side resources and Energy Efficiency resources may be offered directly into RPM Auctions and receive the clearing price without mitigation.

Market Structure

- **PJM Installed Capacity.** During 2012, PJM installed capacity resources increased from 178,854.1 MW on January 1 to 181,990.1 on December 31, primarily due to the integration of the Duke Energy Ohio and Kentucky (DEOK) Control Zone into PJM.
- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity at the end of 2012, 41.8 percent was coal; 28.6 percent was gas; 18.1 percent was nuclear; 6.3 percent was oil; 4.3 percent was hydroelectric; 0.4 percent was solid waste; 0.4 percent was wind, and 0.0 percent was solar.
- **Supply.** Total internal capacity increased 10,070.6 MW from 159,882.7 MW on June 1, 2011, to 169,953.3 MW on June 1, 2012. This increase was the result of the reclassification of the Duquesne resources as internal at the time of the 2012/2013 RPM Base Residual Auction (3,187.2 MW), new generation (785.5 MW), reactivated generation (0.0 MW), net generation capacity modifications (cap mods) (-1,637.3 MW), Demand Resource (DR) modifications (8,028.7 MW), Energy Efficiency (EE) modifications (652.5 MW), the EFORd effect due to lower sell offer EFORds (-944.1 MW), and lower Load Management UCAP conversion factor (-1.9 MW).
- **Demand.** There was a 3,237.4 MW increase in the RPM reliability requirement from 154,251.1 MW on June 1, 2011, to 157,488.5 MW on June 1, 2012. This increase was primarily due to the inclusion of the Duquesne Zone in the preliminary forecast peak load for the 2012/2013 RPM Base Residual Auction. On June 1, 2012, PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 71.9 percent, up slightly from 71.4 percent on June 1, 2011.
- **Market Concentration.** For the 2012/2013, 2013/2014, 2014/2015, and 2015/2016 RPM Auctions, all defined markets failed the preliminary market structure screen (PMSS). In the 2012/2013 RPM First Incremental Auction, 2012/2013 ATSI Integration Auction, 2012/2013 RPM Second Incremental Auction, 2012/2013 RPM Third Incremental Auction, 2013/2014 BRA, 2013/2014 RPM First Incremental Auction, 2013/2014 RPM Second Incremental Auction, and the 2015/2016 BRA failed the three pivotal supplier (TPS) market structure test.[9] In the 2012/2013 BRA, all participants in the RTO as well as MAAC, PSEG North, and DPL South RPM markets failed the TPS test, and six participants included in the incremental supply of EMAAC passed the TPS test. In the 2014/2015 BRA,

6 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).
7 See 126 FERC ¶ 61,275 (2009) at P 88.
8 Transmission constraints are local capacity import capability limitations (low capacity emergency transfer limit (CETL) margin over capacity emergency transfer objective (CETO)) caused by transmission facility limitations, voltage limitations or stability limitations.
9 There are 26 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).

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, would have increased the market clearing price.[10,11,12]

- **Imports and Exports.** Net exchange decreased 2,067.1 MW from June 1, 2011 to June 1, 2012. Net exchange, which is imports less exports, decreased due to a decrease in imports of 2,588.4 MW primarily due to the reclassification of the Duquesne resources to internal, offset by a decrease in exports of 521.3 MW.
- **Demand-Side and Energy Efficiency Resources.** Under RPM, demand-side resources in the Capacity Market decreased by 2,764.9 MW from 9,883.4 MW on June 1, 2011 to 7,118.5 MW on June 1, 2012. Demand-side resources include Demand Resources (DR) and Energy Efficiency (EE) resources cleared in RPM Auctions and certified/forecast interruptible load for reliability (ILR). Effective with the 2012/2013 Delivery Year, ILR was eliminated. Starting with the 2012/2013 Delivery Year and also for incremental auctions in the 2011/2012 Delivery Year, the Energy Efficiency Resource type is eligible to be offered in RPM Auctions.[13]

Market Conduct

- **2012/2013 RPM Base Residual Auction.**[14] Of the 1,133 generation resources which submitted offers, unit-specific offer caps were calculated for 120 resources (10.6 percent). The MMU calculated offer caps for 607 resources (53.6 percent), of which 479 were based on the technology specific default (proxy) ACR values.
- **2012/2013 ATSI Integration Auction.**[15] Of the 173 generation resources which submitted offers, 26 resources elected the offer cap option of 1.1 times the BRA clearing price (15.0 percent). Unit-specific offer caps were calculated for 12 resources (6.9 percent). The MMU calculated offer caps 131 resources (75.7 percent), of which 117 were based on the technology specific default (proxy) ACR values.
- **2012/2013 RPM First Incremental Auction.** Of the 162 generation resources which submitted offers, unit-specific offer caps were calculated for 14 resources (8.6 percent). The MMU calculated offer caps for 108 resources (66.6 percent), of which 92 were based on the technology specific default (proxy) ACR values.
- **2012/2013 RPM Second Incremental Auction.** Of the 188 generation resources which submitted offers, unit-specific offer caps were calculated for 8 resources (4.3 percent). The MMU calculated offer caps for 88 resources (46.8 percent), of which 80 were based on the technology specific default (proxy) ACR values.
- **2012/2013 RPM Third Incremental Auction.** Of the 298 generation resources which submitted offers, unit-specific offer caps were calculated for two generation resources (0.7 percent). The MMU calculated offer caps for 37 generation resources (12.4 percent), of which 35 were based on the technology specific default (proxy) ACR values.
- **2013/2014 RPM Base Residual Auction.**[16] Of the 1,170 generation resources which submitted offers, unit-specific offer caps were calculated for 107 resources (9.1 percent). The MMU calculated offer caps for 700 resources (59.9 percent), of which 587 were based on the technology specific default (proxy) ACR values.
- **2013/2014 RPM First Incremental Auction.** Of the 192 generation resources which submitted offers, unit-specific offer caps were calculated for 27 resources (14.1 percent). The MMU calculated offer caps for 101 resources (52.6 percent), of which

10 OATT Attachment DD (Reliability Pricing Model) § 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).

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

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

15 For a more detailed analysis of the 2012/2013 ATSI Integration Auction, see "Analysis of the 2011/2012 and 2012/2013 ATSI Integration Auctions," <http://www.monitoringanalytics.com/reports/Reports/2011/Analysis_of_2011_2012_and_2012_2013_ATSI_Integration_Auctions_20110114.pdf> (January 14, 2011).

16 For a more detailed analysis of the 2013/2014 RPM Base Residual Auction, 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).

74 were based on the technology specific default (proxy) ACR values.

- **2013/2014 RPM Second Incremental Auction.** Of the 163 generation resources which submitted offers, unit-specific offer caps were calculated for eight generation resources (4.9 percent). The MMU calculated offer caps for 77 generation resources (47.2 percent), of which 65 were based on the technology specific default (proxy) ACR values.
- **2014/2015 RPM Base Residual Auction.**[17] Of the 1,152 generation resources which submitted offers, unit-specific offer caps were calculated for 141 resources (12.2 percent). The MMU calculated offer caps for 698 resources (60.6 percent), of which 550 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 21 generation resources (11.1 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.
- **2015/2016 RPM Base Residual Auction.** Of the 1,168 generation resources which submitted offers, unit-specific offer caps were calculated for 188 generation resources (16.1 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.

Market Performance

- Annual weighted average capacity prices increased from a CCM weighted average price of $5.73 per MW-day in 2006 to an RPM weighted-average price of $164.71 per MW-day in 2010 and then declined to $148.33 per MW-day in 2015.
- RPM net excess decreased 4,661.9 MW from 10,638.4 MW on June 1, 2011, to 5,976.5 MW on June 1, 2012.
- For the 2012/2013 Delivery Year, RPM annual charges to load totaled approximately $3.9 billion.

Generator Performance

- **Forced Outage Rates.** Average PJM EFORd decreased from 7.9 percent in 2011 to 7.5 percent in 2012.18
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor increased from 83.7 percent in 2011 to 84.1 percent in 2012.
- **Outages Deemed Outside Management Control (OMC).** According to North American Electric Reliability Corporation (NERC) criteria, an outage may be classified as an OMC outage if the generating unit outage was caused by other than failure of the owning company's equipment or other than the failure of the practices, policies and procedures of the owning company. In 2012, 12.4 percent of forced outages were classified as OMC outages. OMC outages are excluded from the calculation of the forced outage rate, termed the XEFORd, used to calculate the unforced capacity that must be offered in the PJM Capacity Market.

Conclusion

The Capacity Market is, by design, always tight in the sense that total supply is generally only slightly larger than demand. The demand for capacity includes expected peak load plus a reserve margin. Thus, the reliability goal is to have total supply equal to, or slightly above, the demand for capacity. The market may be long at times, but that is not the equilibrium state. Capacity in excess of demand is not sold and, if it does not earn adequate revenues in other markets or does not have adequate optionality value, will retire. Demand is almost entirely inelastic, because the market rules require loads to purchase their share of the system capacity requirement. The result is that any supplier that owns more capacity than the difference between total supply and the defined demand is pivotal and has market power.

In other words, the market design for capacity leads, almost unavoidably, to structural market power. Given the basic features of market structure in the PJM Capacity Market, including significant market structure issues, inelastic demand, tight supply-demand conditions,

17 For a more detailed analysis of the 2014/2015 RPM Base Residual Auction, see "Analysis of the 2014/2015 RPM Base Residual Auction Report," < http://www.monitoringanalytics.com/reports/Reports/2012/Analysis_of_2014_2015_RPM_Base_Residual_Auction_20120409.pdf> (April 9, 2012).

18 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM Generator Availability Data Systems (GADS) database. This set of capacity resources may include generators in addition to those in the set of generators committed as resources in the RPM. Data is for the twelve months ending December 31, as downloaded from the PJM GADS database on January 25, 2013. EFORd data presented in state of the market reports may be revised based on data submitted after the publication of the reports as generation owners may submit corrections at any time with permission from PJM GADS administrators.

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

The analysis of PJM Capacity Markets begins with market structure, which provides the framework for the actual behavior or conduct of market participants. The analysis examines participant behavior within that market structure. In a competitive market structure, market participants are constrained to behave competitively. The analysis examines market performance, measured by price and the relationship between price and marginal cost, that results from the interaction of market structure and participant behavior.

The MMU found serious market structure issues, measured by the three pivotal supplier test results, by market shares and by the Herfindahl-Hirschman Index (HHI), but no exercise of market power in the PJM Capacity Market in 2012. 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 2012.

The MMU has also identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues. In 2011 and 2012, the MMU prepared a number of RPM-related reports and testimony, shown in Table 4-2.

Table 4-2 RPM Related MMU Reports

Date	Name
January 6, 2011	Analysis of the 2011/2012 RPM First Incremental Auction http://www.monitoringanalytics.com/reports/Reports/2011/Analysis_of_2011_2012_RPM_First_Incremental_Auction_20110106.pdf
January 6, 2011	Impact of New Jersey Assembly Bill 3442 on the PJM Capacity Market http://www.monitoringanalytics.com/reports/Reports/2011/NJ_Assembly_3442_Impact_on_PJM_Capacity_Market.pdf
January 14, 2011	Analysis of the 2011/2012 and 2012/2013 ATSI Integration Auctions http://www.monitoringanalytics.com/reports/Reports/2011/Analysis_of_2011_2012_and_2012_2013_ATSI_Integration_Auctions_20110114.pdf
January 28, 2011	Impact of Maryland PSC's Proposed RFP on the PJM Capacity Market http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Comments_to_MDPSC_Case_No_9214_20110128.pdf
February 1, 2011	Preliminary Market Structure Screen results for the 2014/2015 RPM Base Residual Auction http://www.monitoringanalytics.com/reports/Reports/2011/PMSS_Results_20142015_20110201.pdf
March 4, 2011	IMM Comments re MOPR Filing Nos. EL11-20, ER11-2875 http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Comments_EL11-20-000_ER11-2875-000_20110304.pdf
March 21, 2011	IMM Answer and Motion for Leave to Answer re: MOPR Filing Nos. EL11-20, ER11-2875 http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Answer_and_Motion_for_Leave_to_Answer_EL11-20-000_ER11-2875-000_20110321.pdf
June 2, 2011	IMM Protest re: PJM Filing in Response to FERC Order Regarding MOPR No. ER11-2875-002 http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Protest_ER11-2875-002.pdf
June 17, 2011	IMM Comments re: In the Matter of the Board's Investigation of Capacity Procurement and Transmission Planning No. EO11050309 http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Comments_NJ_EO_11050309_20110617.pdf
June 27, 2011	Units Subject to RPM Must Offer Obligation http://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Units_Subject_to_RPM_Must_Offer_Obligation_20110627.pdf
August 29, 2011	Post Technical Conference Comments re: PJM's Minimum Offer Price Rule Nos. ER11-2875-001, 002, and EL11-20-001 http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Post_Technical_Conference_Comments_ER11-2875_20110829.pdf
September 15, 2011	IMM Motion for Leave to Answer and Answer re: MMU Role in MOPR Review No. ER11-2875-002 http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Motion_for_Leave_to_Answer_and_Answer_ER11-2875-002_20110915.pdf
November 22, 2011	Generator Capacity Resources in PJM Region Subject to "Must Offer" Obligatrion for the 2012/2013, 2013/2014 and 2014/2015 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20111123.pdf
January 9, 2012	IMM Comments re:MOPR Compliance No. ER11-2875-003 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_ER11-2875-003_20120109.pdf
January 20, 2012	IMM Testimony re: Review of the Potential Impact of the Proposed Capacity Additions in the State of Maryland's Joint Petition for Approval of Settlement MD PSC Case No. 9271 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Testimony_MD_PSC_9271.pdf
January 20, 2012	IMM Comments re: Capacity Procurement RFP MD PSC Case No. 9214 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_MD_PSC_9214.pdf
February 7, 2012	Preliminary Market Structure Screen results for the 2015/2016 RPM Base Residual Auction http://www.monitoringanalytics.com/reports/Reports/2012/PMSS_Results_20152016_20120207.pdf
February 15, 2012	RPM-ACR and RPM Must Offer Obligation FAQs http://www.monitoringanalytics.com/Tools/docs/RPM-ACR_FAQ_RPM_Must_Offer_Obligation_20120215.pdf
February 17, 2012	IMM Motion for Clarification re: Minimum Offer Price Rule Revision Nos.ER11-2871-000, -001 and -002, EL11-20-000 and -001 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Motion_for_Clarification_ER11-2875_EL-20_20120217.pdf
April 9, 2012	Analysis of the 2014/2015 RPM Base Residual Auction www.monitoringanalytics.com/reports/Reports/2012/Analysis_of_2014_2015_RPM_Base_Residual_Auction_20120409.pdf
May 1, 2012	IMM Complaint and Request for Fast Track Treatment and Shortened Comment Period re Complaint v. Unnamed Participant No. EL12-63 www.monitoringanalytics.com/report/Report/2012/IMM_Complaint_and_Fast_Track_Treatment_and_Shortened_Comment_Period_EL12-63-000_20120501.pdf
May 17, 2012	IMM Notice of Withdrawal re Complaint v. Unnamed Participant No. EL12-63 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Notice_of_Withdrawal_EL12-63-000_20120517.pdf
July 3, 2012	Generator Capacity Resources in PJM Region Subject to "Must Offer" Obligatrion for the 2013/2014, 2014/2015 and 2015/2016 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20120703.pdf
August 10, 2012	IMM Comments re Capacity Portability AD12-16 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_AD12-16_20120810.pdf
August 20, 2012	IMM and PJM Capacity White Papers on OPSI Issues http://www.monitoringanalytics.com/reports/Reports/2012/IMM_And_PJM_Capacity_White_Papers_On_OPSI_Issues_20120820.pdf
August 29, 2012	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2013/2014, 2014/2015 and 2015/2016 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20120829.pdf
November 29, 2012	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2013/2014, 2014/2015 and 2015/2016 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20121129.pdf
December 11, 2012	Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2012 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Report_Replacement_Capacity_Activity_20121211.pdf

Installed Capacity

On January 1, 2012, PJM installed capacity was 178,854.1 MW (Table 4-3).[19] Over the next five months, unit retirements, facility reratings plus import and export shifts resulted in PJM installed capacity of 185,249.0 MW on May 31, 2012, an increase of 6,394.9 MW or 3.6 percent over the January 1 level.[20,21] The 6,394.9 MW increase was the result of the integration of the DEOK Zone (3,560.4 MW), a decrease in exports (2,122.2 MW), new generation (1,392.2 MW), an increase in imports (203.0 MW), and capacity modifications (140.0 MW), offset by deactivations (971.0 MW) and derates (51.9 MW).

At the beginning of the new planning year on June 1, 2012, PJM installed capacity was 185,732.9 MW, an increase of 489.6 MW or 0.3 percent over the May 31 level. On December 31, 2012, PJM installed capacity was 181,990.1 MW.

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. Prior to January 31, 2010, First, Second and Third Incremental RPM Auctions were conducted 23, 13 and four months prior to the delivery year. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[22] In 2012, a Third Incremental Auction was held in February for the 2012/2013 Delivery Year, the a Base Residual Auction was held in May for the 2015/2016 Delivery Year, a Second Incremental Auction was held in July for the 2013/2014 Delivery Year, and a First Incremental Auction was held in September for the 2014/2015 Delivery Year.

Table 4-3 PJM installed capacity (By fuel source): January 1, May 31, June 1, and December 31, 2012

	1-Jan-12		31-May-12		1-Jun-12		31-Dec-12	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	75,190.4	42.0%	79,311.0	42.8%	79,664.6	42.9%	75,989.2	41.8%
Gas	49,769.3	27.8%	51,180.1	27.6%	51,949.1	28.0%	52,003.2	28.6%
Hydroelectric	8,047.0	4.5%	8,047.0	4.3%	7,879.8	4.2%	7,879.8	4.3%
Nuclear	32,492.6	18.2%	33,085.0	17.9%	33,149.5	17.8%	33,024.0	18.1%
Oil	11,977.3	6.7%	12,260.4	6.6%	11,532.9	6.2%	11,531.2	6.3%
Solar	15.3	0.0%	16.3	0.0%	47.0	0.0%	47.0	0.0%
Solid waste	705.1	0.4%	689.1	0.4%	736.1	0.4%	736.1	0.4%
Wind	657.1	0.4%	660.1	0.4%	779.6	0.4%	779.6	0.4%
Total	178,854.1	100.0%	185,249.0	100.0%	185,738.6	100.0%	181,990.1	100.0%

19 Percent values shown in Table 4-3 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

20 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.

21 Wind resources accounted for 779.6 MW of installed capacity in PJM on December 31, 2012. 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.

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

Market Structure

Supply

As shown in Table 4-4, total internal capacity increased 10,070.6 MW from 159,882.7 MW on June 1, 2011, to 169,953.3 MW on June 1, 2012. This increase was the result of the reclassification of the Duquesne resources as internal at the time of the 2012/2013 RPM Base Residual Auction (3,187.2 MW), new generation (785.5 MW), reactivated generation (0.0 MW), net generation capacity modifications (cap mods) (-1,637.3 MW), Demand Resource (DR) modifications (8,028.7 MW), Energy Efficiency (EE) modifications (652.5 MW), the EFORd effect due to lower sell offer EFORds (-944.1 MW), and lower Load Management UCAP conversion factor (-1.9 MW). The EFORd effect is the measure of the net internal capacity change attributable to EFORd changes and not capacity modifications.

In the 2013/2014, 2014/2015, and 2015/2016 auctions, new generation were 8,929.0 MW; reactivated generation were 8.1 MW and net generation cap mods were -7,080.2 MW. DR and Energy Efficiency (EE) modifications totaled 14,645.8 MW through June 1, 2015. An increase of 77.4 MW was due to lower EFORds, and an increase of 63.1 MW was due to a higher Load Management UCAP conversion factor. The integration of the American Transmission Systems, Inc. (ATSI) Zone resources added 13,175.2 MW to total internal capacity, and the integration of the DEOK Zone resources added 4,816.8 MW to total internal capacity. A decrease of 31.2 MW was due to a correction in resource modeling. The net effect from June 1, 2012, through June 1, 2015, was an increase in total internal capacity of 36,604.0 MW (20.4 percent) from 169,953.3 MW to 204,557.3 MW.

As shown in Table 4-4 and Table 4-13, in the 2012/2013 auction, the increase of eight generation resources consisted of 16 new resources (772.5 MW), four resources that were previously entirely FRR committed (13.4 MW), three additional resources imported (276.8 MW), two additional resources resulting from disaggregation of RPM resources, and one resource formerly unoffered (1.9 MW), offset by nine retired resources (1,044.5 MW), four additional resources committed fully to FRR (39.5 MW), four less resources resulting from aggregation of RPM resources, and one less external resource that did not offer (663.2 MW). In addition, there were the following retirements of resources that were either exported or excused in the 2011/2012 BRA: two combustion turbine resources (5.3 MW) and three combined cycle resources (297.6 MW). Also, resources that are no longer PJM capacity resources consisted of three CT units (521.5 MW) in the RTO. The new resources consisted of six new diesel resources (13.9 MW), four new wind resources (57.9 MW), three new steam units (560.4 MW), and three new CT units (140.3 MW).

As shown in Table 4-4 and Table 4-14, in the 2013/2014 auction, the increase of 37 generation resources consisted of 63 ATSI resources that were not offered in the 2012/2013 BRA (11,325.4 MW), 31 new resources (1,038.2 MW), four resources that were previously entirely Fixed Resource Requirement (FRR) committed (234.3 MW), and four additional resources imported (460.1 MW). The reduction in generation resources consisted of seven retired resources (824.0 MW), two deactivated resources (66.6 MW), 49 additional resources committed fully to FRR (307.7 MW), four less planned generation resources that were not offered (249.3 MW), two additional resources excused from offering (4.2 MW), and one less external resource that was not offered (45.7 MW). In addition, there were the following retirements of resources that were either exported or excused in the 2012/2013 BRA: three steam units (125.9 MW). The new generation capacity resources consisted of 11 solar resources (9.5 MW), 11 wind resources (245.7 MW), four combined cycle units (671.5 MW), three diesel resources (5.4 MW), one steam unit (23.8 MW), and one CT unit (82.3 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 2013/2014 Delivery Year: four wind resources (66.2 MW).

As shown in Table 4-4 and Table 4-15, 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 4-4 and Table 4-16, 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).

Table 4-5 shows generation capacity additions since the implementation of the Reliability Pricing Model. New generation capacity resources (13,809.3 MW), reactivated generation capacity resources (858.7 MW), uprates to existing generation capacity resources (5,957.0 MW), and the net increase in capacity imports (6,754.6 MW) totals 27,379.6 MW since the implementation of the Reliability Pricing Model.

Table 4-4 Internal capacity: June 1, 2011 to June 1, 2015[23]

	UCAP (MW)								
	RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI
Total internal capacity @ 01-Jun-11	159,882.7	66,329.7	32,733.0	11,684.2	1,460.3	7,425.8	4,167.5		
Reclassification of Duquesne resources to internal	3,187.2	0.0	0.0	0.0	0.0	0.0	0.0		
New generation	785.5	173.1	59.7	0.0	0.0	0.0	0.0		
Reactivated generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
Generation cap mods	(1,637.3)	(1,012.5)	(444.9)	(540.0)	(31.8)	(379.2)	(509.0)		
DR mods	8,028.7	3,829.7	1,480.9	1,076.9	64.6	423.3	67.6		
EE mods	652.5	186.9	24.4	162.3	0.0	4.1	0.9		
EFORd effect	(944.1)	(502.1)	(185.1)	47.3	5.8	(42.6)	18.3		
DR and EE effect	(1.9)	(0.9)	(0.5)	(0.4)	0.0	0.0	0.0		
Total internal capacity @ 01-Jun-12	169,953.3	69,003.9	33,667.5	12,430.3	1,498.9	7,431.4	3,745.3	5,416.0	
Correction in resource modeling	0.0	13.0	0.0	0.0	81.3	0.0	28.5	0.0	
Adjusted internal capacity @ 01-Jun-12	169,953.3	69,016.9	33,667.5	12,430.3	1,580.2	7,431.4	3,773.8	5,416.0	
Integration of existing ATSI resources	13,175.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
New generation	1,104.4	172.5	110.3	1.8	0.0	108.8	101.9	1.8	
Reactivated generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Generation cap mods	(969.4)	(1,007.7)	(884.9)	(113.8)	12.4	(180.2)	(180.2)	(11.0)	
DR mods	1,894.1	900.2	689.5	(207.4)	9.7	646.1	431.2	61.8	
EE mods	100.8	(34.9)	(0.3)	(51.9)	(8.1)	3.3	(0.3)	(20.7)	
EFORd effect	(589.3)	27.7	117.5	(292.5)	18.1	26.0	48.3	(159.4)	
DR and EE effect	9.1	4.2	1.0	1.8	0.1	0.2	0.1	0.4	
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	
Correction in resource modeling	(31.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Adjusted internal capacity @ 01-Jun-13	184,647.0	69,078.9	33,700.6	11,768.3	1,612.4	8,035.6	4,174.8	5,288.9	
Integration of existing DEOK resources	4,816.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
New generation	1,038.5	875.8	697.2	2.7	48.0	6.8	1.5	0.0	
Reactivated generation	8.1	8.1	8.1	0.0	0.0	8.1	0.0	0.0	
Generation cap mods	(991.9)	(175.2)	(102.3)	(242.8)	(161.9)	9.3	(0.5)	(2.8)	
DR mods	6,940.0	6,653.8	2,438.6	2,727.5	241.9	547.0	205.0	681.7	
EE mods	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

23 The RTO includes MAAC, EMAAC, SWMAAC, and ATSI. MAAC includes EMAAC and SWMAAC. EMAAC includes DPL South, PSEG and PSEG North. SWMAAC includes Pepco.

Table 4-5 RPM generation capacity additions: 2007/2008 through 2015/2016

	ICAP (MW)				
Delivery Year	New Generation Capacity Resources	Reactivated Generation Capacity Resources	Uprates to Existing Generation Capacity Resources	Net Increase in Capacity Imports	Total
2007/2008	19.0	47.0	536.0	1,576.6	2,178.6
2008/2009	145.1	131.0	438.1	107.7	821.9
2009/2010	476.3	0.0	793.3	105.0	1,374.6
2010/2011	1,031.5	170.7	876.3	24.1	2,102.6
2011/2012	2,332.5	501.0	896.8	672.6	4,402.9
2012/2013	901.5	0.0	946.6	676.8	2,524.9
2013/2014	1,080.2	0.0	418.2	963.3	2,461.7
2014/2015	1,102.8	9.0	482.5	818.9	2,413.2
2015/2016	6,720.4	0.0	569.2	1,809.6	9,099.2
Total	13,809.3	858.7	5,957.0	6,754.6	27,379.6

Demand

There was a 3,237.4 MW increase in the RPM reliability requirement from 154,251.1 MW on June 1, 2011, to 157,488.5 MW on June 1, 2012. This decrease was primarily due to the inclusion of the Duquesne Zone in the preliminary forecast peak load for the 2012/2013 RPM Base Residual Auction.

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, 2012, PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 71.9 percent (Table 4-6), up slightly from 71.4 percent on June 1, 2011. The combined market share of LSEs not affiliated with any EDC and of non-PJM EDC affiliates was 28.1 percent, down slightly from 28.6 percent on June 1, 2011. Prior to the 2012/2013 Delivery Year, obligation is 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.

Table 4-6 PJM Capacity Market load obligation served: June 1, 2012

	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	52,835.1	40,829.7	15,141.3	4,901.4	13,141.3	6,038.7	18,526.8	151,414.3
Percent of total obligation	34.9%	27.0%	10.0%	3.2%	8.7%	4.0%	12.2%	100.0%

Market Concentration

Preliminary Market Structure Screen

Under the terms of the PJM Open Access Transmission Tariff (OATT) effective prior to December 17, 2012, the MMU was required to apply the preliminary market structure screen (PMSS) prior to RPM Base Residual Auctions.[24] The results of the PMSS were applicable for all RPM Auctions for the given delivery year. The purpose of the PMSS was to determine whether additional data were needed from owners of capacity resources in the defined areas in order to permit the application of market structure tests defined in the Tariff.

An LDA or the RTO Region failed the PMSS if any one of the following three screens were failed: the market share of any capacity resource owner exceeded 20 percent; the HHI for all capacity resource owners was 1800 or higher; or there were not more than three jointly pivotal suppliers. As shown in Table 4-7, all defined markets failed the preliminary market structure screen (PMSS) for the 2015/2016 Delivery Year.[25] As a result, all capacity market sellers owning or controlling any generation capacity resource located in the entire PJM Region were required to provide the information specified in Section 6.7(b) of Attachment DD of the PJM Open Access Transmission Tariff (OATT).

Table 4-7 Preliminary market structure screen results: 2012/2013 through 2015/2016 RPM Auctions

RPM Markets	Highest Market Share	HHI	Pivotal Suppliers	Pass/Fail
2012/2013				
RTO	17.4%	853	1	Fail
MAAC	17.6%	1071	1	Fail
EMAAC	32.8%	2057	1	Fail
SWMAAC	50.7%	4338	1	Fail
PSEG	84.3%	7188	1	Fail
PSEG North	90.9%	8287	1	Fail
DPL South	55.0%	3828	1	Fail
2013/2014				
RTO	14.4%	812	1	Fail
MAAC	18.1%	1101	1	Fail
EMAAC	33.0%	1992	1	Fail
SWMAAC	50.9%	4790	1	Fail
PSEG	89.7%	8069	1	Fail
PSEG North	89.5%	8056	1	Fail
DPL South	55.8%	3887	1	Fail
JCPL	28.5%	1731	1	Fail
Pepco	94.5%	8947	1	Fail
2014/2015				
RTO	15.0%	800	1	Fail
MAAC	17.6%	1038	1	Fail
EMAAC	33.1%	1966	1	Fail
SWMAAC	49.4%	4733	1	Fail
PSEG	89.4%	8027	1	Fail
PSEG North	88.2%	7825	1	Fail
DPL South	56.5%	3796	1	Fail
Pepco	94.5%	8955	1	Fail
2015/2016				
RTO	14.3%	763	1	Fail
MAAC	17.5%	1114	1	Fail
EMAAC	32.6%	1904	1	Fail
SWMAAC	51.9%	4745	1	Fail
DPL South	49.2%	3257	1	Fail
PSEG	89.4%	8020	1	Fail
PSEG North	88.0%	7794	1	Fail
Pepco	94.1%	8876	1	Fail
ATSI	75.5%	5881	1	Fail

Auction Market Structure

As shown in Table 4-8, all participants in the total PJM market as well as the LDA RPM markets failed the Three Pivotal Supplier (TPS) test in the 2012/2013 RPM First Incremental Auction, the 2012/2013 ATSI FRR Integration Auction, the 2012/2013 RPM Second Incremental Auction, the 2012/2013 RPM Third Incremental Auction, the 2013/2014 BRA, the 2013/2014 RPM First Incremental Auction, the 2013/2014 RPM

24 OATT Attachment M (PJM Market Monitoring Plan)-Appendix § II.D.1. The rules for PMSS were eliminated, effective December 17, 2012, by letter order in FERC Docket No. ER13-149 (November 28, 2012).

25 See "Preliminary Market Structure Screen Results for 2015/2016 RPM Base Residual Auction" (February 7, 2012) <http://www.monitoringanalytics.com/reports/Reports/2012/PMSS_Results_20152016_20120207.pdf>.

Second Incremental Auction, and the 2015/2016 BRA.[26] The result was that offer caps were applied to all sell offers for resources which were subject to mitigation when the Capacity Market Seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[27,28,29] In the 2012/2013 BRA, all participants included in the incremental supply of EMAAC passed the test. In the 2014/2015 BRA, all participants included in the incremental supply in MAAC passed the test. 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.[30] 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 4-8 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 (RSI3). 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.

26 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.

27 See OATT Attachment DD § 6.5.

28 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.

29 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).

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

Table 4-8 RSI results: 2012/2013 through 2015/2016 RPM Auctions[31]

RPM Markets	$RSI_{1\ 1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
2012/2013 BRA				
RTO	0.84	0.63	98	98
MAAC/SWMAAC	0.77	0.54	15	15
EMAAC/PSEG	0.00	7.03	6	0
PSEG North	0.00	0.00	2	2
DPL South	0.00	0.00	3	3
2012/2013 ATSI FRR Integration Auction				
RTO	0.34	0.10	16	16
2012/2013 First Incremental Auction				
RTO/MAAC/SWMAAC/PSEG/PSEG North/DPL South	0.40	0.60	25	25
EMAAC	0.40	0.00	2	2
2012/2013 Second Incremental Auction				
RTO/MAAC/SWMAAC/PSEG/PSEG North/DPL South	0.62	0.64	33	33
EMAAC	0.00	0.00	2	2
2012/2013 Third Incremental Auction				
RTO/MAAC/EMAAC/SWMAAC/PSEG/PSEG North/DPL South	0.39	0.28	53	53
2013/2014 BRA				
RTO	0.80	0.59	87	87
MAAC/SWMAAC	0.42	0.23	9	9
EMAAC/PSEG/PSEG North/DPL South	0.25	0.00	2	2
Pepco	0.00	0.00	1	1
2013/2014 First Incremental Auction				
RTO/MAAC	0.24	0.28	33	33
EMAAC/PSEG/PSEG North/DPL South	0.34	0.00	3	3
SWMAAC/Pepco	0.00	0.00	0	0
2013/2014 Second Incremental Auction				
RTO	0.44	0.27	32	32
MAAC/SWMAAC/Pepco	0.00	0.00	0	0
EMAAC/PSEG/PSEG North/DPL South	0.00	0.00	0	0
2014/2015 BRA				
RTO	0.76	0.58	93	93
MAAC/SWMAAC/EMAAC/PSEG/DPL South/Pepco	1.40	1.03	7	0
PSEG North	0.00	0.00	1	1
2014/2015 First Incremental Auction				
RTO	0.45	0.14	36	36
MAAC/SWMAAC/EMAAC/PSEG/DPL South/Pepco	0.00	0.00	1	1
PSEG North	0.00	0.00	1	1
2015/2016 BRA				
RTO	0.75	0.57	99	99
MAAC/EMAAC/SWMAAC/PSEG/PSEG North/DPL South/Pepco	0.49	0.63	12	12
ATSI	0.01	0.00	3	3

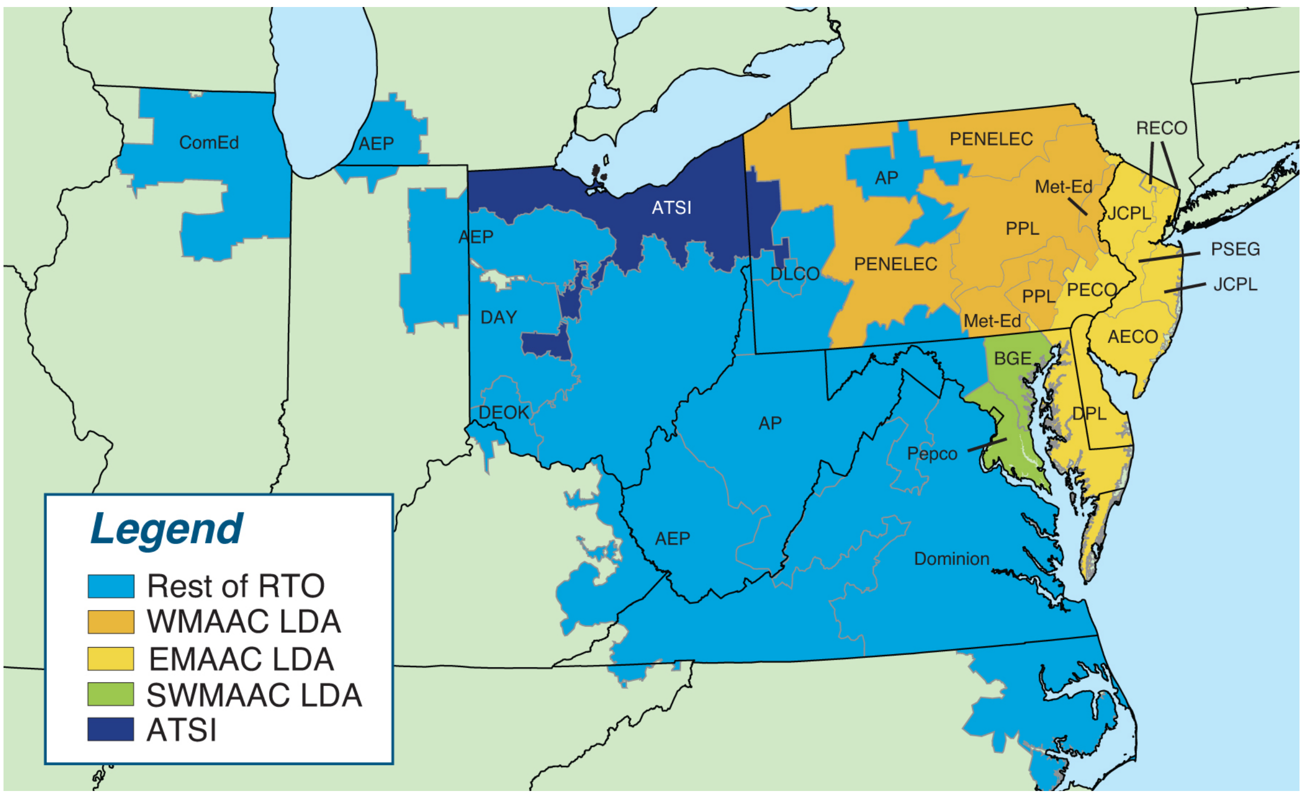
31 The RSI shown is the lowest RSI in the market.

Locational Deliverability Areas (LDAs)

Under the PJM Tariff, PJM determines, in advance of each BRA, whether defined Locational Deliverability Areas (LDAs) will be modeled in the auction. Effective with the 2012/2013 delivery year, an LDA will be modeled as a potentially constrained LDA for a delivery year if the Capacity Emergency Transfer Limit (CETL) is less than 1.15 times the Capacity Emergency Transfer Objective (CETO), such LDA had a locational price adder in one or more of the three immediately preceding BRAs, or such LDA is determined by PJM in a preliminary analysis to be likely to have a locational price adder based on historic offer price levels. The rules also provide that starting with the 2012/2013 delivery year, EMAAC, SWMAAC, and MAAC LDAs will be modeled as potentially constrained LDAs regardless of the results of the above three tests.[32] 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."[33] A reliability requirement, a Variable Resource Requirement (VRR) curve, a Minimum Annual Resource Requirement, and a Minimum Extended Summer Resource Requirement are established for each modeled LDA.

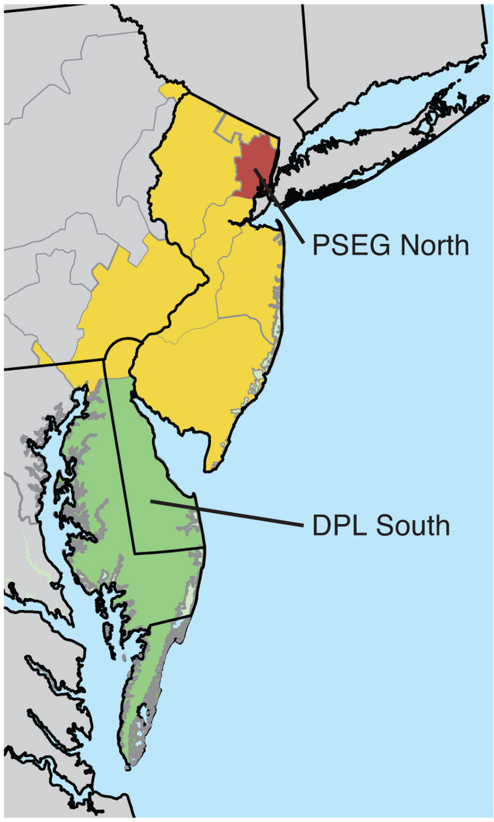
Locational Deliverability Areas are shown in Figure 4-1 and Figure 4-2.

Figure 4-1 PJM Locational Deliverability Areas



32 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.
33 OATT Attachment DD § 5.10 (a) (ii).

Figure 4-2 PJM RPM EMAAC subzonal LDAs



Imports and Exports

Units external to the metered boundaries of PJM can qualify as PJM 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 outside PJM.[34]

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 is assured by the requirements for firm transmission service. 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 requirements.[35, 36] 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 Market.[37]

To avoid balancing market deviations, any offer accepted in the Day-Ahead Market must be scheduled to physically flow in the Real-Time Market. When submitting the Real-Time Market transaction, a valid NERC Tag is required, with the appropriate transmission reservations associated. Additionally, external capacity

34 OATT Attachment DD § 5.6.6(b).

35 See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region", Schedule 9 & 10.

36 See PJM. "Manual 18: PJM Capacity Market", Revision 17 (December 20, 2012), pp. 39-41 & p. 58.

37 OATT, Schedule 1, Section 1.10.1A.

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 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.

Planned External Generation Capacity Resource

Planned External Generation Capacity Resources are eligible to be offered into an RPM Auction if they meet specific requirements.[38, 39] 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.[40] 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.[41]

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.[42] The Capacity Market Seller must also identify the megawatt amount, export zone, and time period (in days) of the export.[43]

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.[44]

When submitting a Real-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.

As shown in Table 4-9, net exchange decreased 2,067.1 MW from June 1, 2011 to June 1, 2012. Net exchange, which is imports less exports, decreased due to a decrease in imports of 2,588.4 MW primarily due to the reclassification of the Duquesne resources to internal, offset by a decrease in exports of 521.3 MW.

38 See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region", Section 1.69A.

39 See PJM. "Manual 18: PJM Capacity Market", Revision 17 (December 20, 2012), pp. 42-43.

40 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).

41 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).

42 OATT Attachment DD § 6.6(g).

43 *Id.*

44 OATT Attachment M-Appendix § II.C.2.

Table 4-9 PJM capacity summary (MW): June 1, 2007 to June 1, 2015[45]

	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
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
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
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
Make-whole	0.0	0.0	0.0	0.0	43.0	222.1	14.0	112.6	2.7
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
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
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
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
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)
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
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
EE cleared						568.9	679.4	822.1	922.5
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
Short-Term Resource Procurement Target						3,343.3	3,749.7	3,708.1	4,069.4

Demand-Side Resources

There are three basic demand side products incorporated in the RPM market design:[46]

- **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 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.[47] 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.[48]

Effective with the 2014/2015 Delivery Year, there are three types of Demand Resource products incorporated into the RPM market design:[49, 50]

- **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

45 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.

46 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.

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

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

49 134 FERC ¶ 61,066 (2011).

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

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 4-10 and Table 4-12, capacity in the RPM load management programs was 7,118.5 MW for June 1, 2012 as a result of cleared capacity for Demand Resources and Energy Efficiency Resources in RPM Auctions for the 2012/2013 Delivery Year (9,407.0 MW) less replacement capacity (2,288.5 MW). Table 4-11 shows RPM commitments for DR and EE resources as the result of RPM Auctions prior to adjustments for replacement capacity transactions and certified ILR.

Table 4-10 RPM load management statistics by LDA: June 1, 2011 to June 1, 2015[51,52]

	UCAP (MW)								
	RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI
DR cleared	1,826.6								
EE cleared	76.4								
DR net replacements	(1,052.4)								
EE net replacements	0.2								
ILR	9,032.6								
RPM load management @ 01-Jun-11	9,883.4								
DR cleared	8,740.9	5,193.6	1,971.8	1,794.4	71.0	517.8	97.9		
EE cleared	666.1	253.6	48.1	160.1	0.0	15.9	7.8		
DR net replacements	(2,253.6)	(1,848.6)	(761.5)	(645.5)	(30.6)	(182.9)	10.1		
EE net replacements	(34.9)	(32.4)	(16.2)	(16.5)	0.0	(3.0)	(1.0)		
RPM load management @ 01-Jun-12	7,118.5	3,566.2	1,242.2	1,292.5	40.4	347.8	114.8		
DR cleared	10,458.8	6,297.6	2,702.1	1,788.6	155.4	1,185.0	534.8	661.7	
EE cleared	870.9	269.6	61.3	133.1	6.8	26.2	9.4	56.3	
DR net replacements	(558.1)	(662.3)	(471.3)	(91.8)	(3.1)	(440.6)	(197.0)	(54.3)	
EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
RPM load management @ 01-Jun-13	10,771.6	5,904.9	2,292.1	1,829.9	159.1	770.6	347.2	663.7	
DR cleared	14,226.8	7,320.0	2,923.5	2,250.3	220.9	989.5	468.0	908.5	
EE cleared	956.4	276.9	35.2	169.8	8.1	14.9	7.6	51.4	
DR net replacements	(5.9)	(5.4)	(2.4)	(0.3)	0.0	(0.6)	0.0	0.0	
EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
RPM load management @ 01-Jun-14	15,177.3	7,591.5	2,956.3	2,419.8	229.0	1,003.8	475.6	959.9	
DR cleared	14,832.8	6,648.7	2,610.4	2,009.1	86.3	796.1	263.3	867.4	1,763.7
EE cleared	922.5	222.6	42.2	159.4	0.0	10.7	3.1	55.8	44.9
DR net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RPM load management @ 01-Jun-15	15,755.3	6,871.3	2,652.6	2,168.5	86.3	806.8	266.4	923.2	1,808.6

51 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.

52 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 4-11 RPM load management cleared capacity and ILR: 2007/2008 through 2015/2016[53,54,55]

	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	10,037.5	10,458.8	839.1	870.9	0.0	0.0
2014/2015	13,717.4	14,226.8	923.9	956.4	0.0	0.0
2015/2016	14,303.2	14,832.8	890.8	922.5	0.0	0.0

Table 4-12 RPM load management statistics: June 1, 2007 to June 1, 2015[56,57]

	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	10,876.6	11,329.7	(535.6)	(558.1)	0.0	0.0	10,341.0	10,771.6
01-Jun-14	14,641.3	15,183.2	(5.7)	(5.9)	0.0	0.0	14,635.6	15,177.3
01-Jun-15	15,194.0	15,755.3	0.0	0.0	0.0	0.0	15,194.0	15,755.3

53 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.

54 FRR committed load management resources are not included in this table.

55 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.

56 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.

57 FRR committed load management resources are not included in this table.

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.[58,59,60]

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.[61] In effect, avoidable costs are the costs that a generation owner would not incur if the generating unit were mothballed for the year. 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.[62]

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. 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. The 2015/2016 RPM Base Residual Auction was the second BRA conducted under the revised MOPR and the first conducted under the subsequent FERC Orders related to the MOPR, including clarification on the duration of mitigation, which resources are subject to MOPR, and the MOPR review process.

The MOPR provides for a unit specific review by the MMU and PJM of sell offers for new resources and uprates that fall below the MOPR reference value. The reference value is 90 percent of the net CONE value for a combustion turbine or combined cycle unit. The reference value sets a standard that applies except in specific cases where the facts and circumstances of a particular project support a value lower than the reference value. The MMU conducted unit specific reviews of requests for exceptions to the MOPR reference value. When conducting unit specific reviews, the MMU applied the analytical approach used in the calculation of the gross CONE, which is used as an input to the VRR curve, and reviewed unit specific net revenue projections which offset gross CONE values. A critical difference between the MOPR definition of cost and the definition of net CONE is that net CONE uses the three year historical average net revenue for the reference unit while the MOPR definition includes projected net revenues. At times when forward market prices are well above historical prices, this difference can have a very significant impact on the calculation of unit specific net costs. For example, the same unit used as the reference unit for gross CONE could have a net cost well below net CONE solely as a result of these differences in the net revenue offset. The impact on net CONE is larger for combined cycle units, which generally receive a larger share of gross CONE from net revenues than do combustion turbines, the gross CONE unit type used as an input parameter for the VRR curve.

58 See OATT Attachment DD § 6.5.

59 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.

60 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).

61 OATT Attachment DD § 6.8 (b).

62 OATT Attachment DD § 6.8 (a).

Table 4-13 ACR statistics: 2012/2013 RPM Auctions

	2012/2013 Base Residual Auction		2012/2013 ATSI Integration Auction		2012/2013 First Incremental Auction		2012/2013 Second Incremental Auction		2012/2013 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	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	465	41.0%	117	67.6%	92	56.8%	80	42.6%	35	11.7%
ACR data input (APIR)	118	10.4%	12	6.9%	14	8.6%	8	4.3%	2	0.7%
ACR data input (non-APIR)	2	0.2%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Opportunity cost input	8	0.7%	2	1.2%	2	1.2%	0	0.0%	0	0.0%
Default ACR and opportunity cost	14	1.2%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Offer cap of 1.1 times BRA clearing price elected	NA	NA	26	15.0%	NA	NA	NA	NA	130	43.6%
Uncapped planned uprate and default ACR	NA	NA	NA	NA	NA	NA	3	1.6%	0	0.0%
Uncapped planned uprate and opportunity cost	NA	NA	NA	NA	NA	NA	0	0.0%	0	0.0%
Uncapped planned uprate and price taker	NA	NA	NA	NA	NA	NA	2	1.1%	2	0.7%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	NA	NA	NA	NA	NA	NA	1	0.3%
Uncapped planned generation resources	11	1.0%	0	0.0%	17	10.5%	12	6.4%	10	3.4%
Price takers	515	45.5%	16	9.2%	37	22.8%	83	44.1%	118	39.6%
Total Generation Capacity Resources offered	1,133	100.0%	173	100.0%	162	100.0%	188	100.0%	298	100.0%

Table 4-14 ACR statistics: 2013/2014 RPM Auctions

	2013/2014 Base Residual Auction		2013/2014 First Incremental Auction		2013/2014 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	580	49.6%	70	36.5%	55	33.7%
ACR data input (APIR)	92	7.9%	27	14.1%	8	4.9%
ACR data input (non-APIR)	15	1.3%	0	0.0%	0	0.0%
Opportunity cost input	6	0.5%	0	0.0%	4	2.5%
Default ACR and opportunity cost	7	0.6%	4	2.1%	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	NA	NA	3	1.6%	10	6.1%
Uncapped planned uprate and opportunity cost	NA	NA	0	0.0%	0	0.0%
Uncapped planned uprate and price taker	NA	NA	1	0.5%	5	3.1%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	NA	NA	NA	NA
Uncapped planned generation resources	20	1.7%	1	0.5%	11	6.7%
Price takers	450	38.5%	86	44.8%	70	42.9%
Total Generation Capacity Resources offered	1,170	100.0%	192	100.0%	163	100.0%

Table 4-15 ACR statistics: 2014/2015 RPM Auctions

	2014/2015 Base Residual Auction		2014/2015 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	544	47.2%	59	31.1%
ACR data input (APIR)	138	12.0%	21	11.1%
ACR data input (non-APIR)	3	0.3%	0	0.0%
Opportunity cost input	7	0.6%	4	2.1%
Default ACR and opportunity cost	6	0.5%	1	0.5%
Offer cap of 1.1 times BRA clearing price elected	NA	NA	NA	NA
Uncapped planned uprate and default ACR	11	1.0%	11	5.8%
Uncapped planned uprate and opportunity cost	0	0.0%	0	0.0%
Uncapped planned uprate and price taker	6	0.5%	4	2.1%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	NA	NA
Uncapped planned generation resources	22	1.9%	5	2.6%
Price takers	415	36.0%	85	44.7%
Total Generation Capacity Resources offered	1,152	100.0%	190	100.0%

Table 4-16 ACR statistics: 2015/2016 RPM Auctions

	2015/2016 Base Residual Auction	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	449	38.4%
ACR data input (APIR)	171	14.6%
ACR data input (non-APIR)	17	1.5%
Opportunity cost input	4	0.3%
Default ACR and opportunity cost	4	0.3%
Offer cap of 1.1 times BRA clearing price elected	NA	NA
Uncapped planned uprate and default ACR	25	2.1%
Uncapped planned uprate and opportunity cost	0	0.0%
Uncapped planned uprate and price taker	7	0.6%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA
Uncapped planned generation resources	32	2.7%
Price takers	459	39.3%
Total Generation Capacity Resources offered	1,168	100.0%

Table 4-17 APIR statistics: 2012/2013 RPM Auctions[63, 64]

		Weighted-Average ($ per MW-day UCAP)					
		Combined Cycle	Combustion Turbine	Oil or Gas Steam	Subcritical/ Supercritical Coal	Other	Total
2012/2013 BRA							
Non-APIR units	ACR	$41.84	$32.61	$75.47	$207.54	$57.18	$110.84
	Net revenues	$91.67	$35.29	$7.51	$396.82	$257.96	$208.65
	Offer caps	$5.28	$14.40	$67.96	$11.31	$15.63	$13.74
APIR units	ACR	$218.10	$49.83	$177.52	$715.10	NA	$464.65
	Net revenues	$98.97	$15.62	$3.62	$508.00	NA	$302.04
	Offer caps	$119.12	$34.96	$173.89	$215.38	NA	$167.62
	APIR	$218.10	$26.59	$89.08	$559.97	NA	$351.74
	Maximum APIR effect						$1,155.57
2012/2013 First IA							
Non-APIR units	ACR	$69.71	$30.49	$86.40	$229.86	$32.75	$67.26
	Net revenues	$136.19	$5.75	$12.73	$156.50	$33.52	$30.71
	Offer caps	$32.88	$24.75	$73.67	$75.99	$27.72	$37.81
APIR units	ACR	NA	$50.56	$289.38	$660.56	NA	$367.75
	Net revenues	NA	$9.15	$50.16	$434.48	NA	$138.16
	Offer caps	NA	$41.40	$239.21	$226.09	NA	$229.59
	APIR	NA	$7.70	$156.87	$459.80	NA	$222.35
	Maximum APIR effect						$549.57

Table 4-18 APIR statistics: 2013/2014 RPM Auctions[65]

		Weighted-Average ($ per MW-day UCAP)					
		Combined Cycle	Combustion Turbine	Oil or Gas Steam	Subcritical/ Supercritical Coal	Other	Total
2013/2014 BRA							
Non-APIR units	ACR	$44.51	$33.30	$79.91	$212.68	$52.57	$115.83
	Net revenues	$110.63	$30.53	$12.72	$364.90	$259.34	$199.44
	Offer caps	$6.84	$16.36	$68.15	$9.29	$14.30	$14.09
APIR units	ACR	NA	$49.42	$341.77	$509.95	$305.48	$390.05
	Net revenues	NA	$9.18	$63.80	$459.41	$187.40	$292.92
	Offer caps	NA	$40.73	$277.96	$112.30	$118.09	$134.44
	APIR	NA	$25.28	$243.47	$352.55	$1.69	$268.59
	Maximum APIR effect						$1,304.36
2013/2014 First IA							
Non-APIR units	ACR	$38.49	$61.44	$151.08	$229.06	$51.00	$146.81
	Net revenues	$13.95	$13.45	$2.05	$132.63	$352.30	$79.75
	Offer caps	$27.94	$48.02	$149.04	$96.88	$21.59	$71.30
APIR units	ACR	NA	$44.20	$445.02	$528.57	NA	$426.53
	Net revenues	NA	$0.84	$74.60	$380.16	NA	$266.48
	Offer caps	NA	$43.36	$370.40	$148.41	NA	$160.05
	APIR	NA	$12.56	$295.56	$329.36	NA	$265.55
	Maximum APIR effect						$593.49

63 The weighted-average offer cap can be positive even when the weighted-average net revenues are higher than the weighted-average ACR, because the unit-specific offer caps are never less than zero. On a unit basis, if net revenues are greater than ACR, the offer cap is zero.

64 For reasons of confidentiality, the APIR statistics do not include opportunity cost based offer cap data or results from the 2012/2013 RPM Second Incremental Auction or the 2012/2013 RPM Third Incremental Auction.

65 For reasons of confidentiality, the APIR statistics do not include opportunity cost based offer cap data or results from the 2013/2014 RPM Second Incremental Auction.

Table 4-19 APIR statistics: 2014/2015 RPM Auction

		Weighted-Average ($ per MW-day UCAP)					
		Combined Cycle	Combustion Turbine	Oil or Gas Steam	Subcritical/ Supercritical Coal	Other	Total
2014/2015 BRA							
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
2014/2015 First IA							
Non-APIR units	ACR	$37.22	$29.94	$77.94	$223.40	$41.44	$197.18
	Net revenues	$139.02	$12.59	$18.66	$156.75	$82.18	$136.68
	Offer caps	$1.13	$17.35	$59.28	$93.14	$33.01	$83.55
APIR units	ACR	NA	$440.52	$328.42	$329.08	NA	$331.18
	Net revenues	NA	$41.67	$8.28	$245.05	NA	$229.92
	Offer caps	NA	$398.85	$320.14	$110.70	NA	$126.15
	APIR	NA	$417.50	$70.39	$119.70	NA	$123.05
	Maximum APIR effect						$761.69

Table 4-20 APIR statistics: 2015/2016 RPM Auction

		Weighted-Average ($ per MW-day UCAP)					
		Combined Cycle	Combustion Turbine	Oil or Gas Steam	Subcritical/ Supercritical Coal	Other	Total
2015/2016 BRA							
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

2012/2013 RPM Base Residual Auction

As shown in Table 4-13, 1,133 generation resources submitted offers in the 2012/2013 RPM Auction as compared to 1,125 generation resources offered in the 2011/2012 RPM Auction. Unit-specific offer caps were calculated for 120 generation resources (10.6 percent of all generation resources offered) including 118 generation resources (10.4 percent) with an APIR component and 2 resources (0.2 percent) without an APIR component. The MMU calculated offer caps for 607 generation resources (53.6 percent), of which 479 (42.3 percent) were based on the technology specific default (proxy) ACR values. Of the 1,125 generation resources, 11 planned generation resources had uncapped offers (1.0 percent), while the remaining 515 generation resources were price takers (45.5 percent), of which the offers for 512 generation resources were zero and the offers for three generation resources were set to zero because no data were submitted.

Of the 1,133 generation resources which submitted offers, 118 (10.4 percent) included an APIR component. As shown in Table 4-17, the weighted-average gross ACR for resources with APIR ($464.65 per MW-day) and the weighted-average offer caps, net of net revenues, for resources with APIR ($167.62 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 $351.74 per MW-day to the ACR value of the APIR resources. The default ACR values included an average APIR of $1.31 per MW-day. The highest APIR for a technology ($559.97 per MW-day) was for subcritical/supercritical coal resources. The maximum APIR effect ($1,155.57 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

2012/2013 ATSI Integration Auction

As shown in Table 4-13, 173 generation resources submitted offers in the 2012/2013 ATSI Integration Auction. Unit-specific offer caps were calculated for 12 generation resources (6.9 percent of all generation resources), all of which included an APIR component. The MMU calculated offer caps for 131 generation resources (75.7 percent), of which 117 were based on the technology specific default (proxy) ACR values. Of the 173 generation resources, 26 generation resources elected offer cap option of 1.1 times the BRA clearing price (15.0 percent), while the remaining 16 generation resources were price takers (9.3 percent), of which the offers for 13 resources were zero and the offers for three resources were set to zero because no data were submitted.

2012/2013 RPM First Incremental Auction

As shown in Table 4-13, 162 generation resources submitted offers in the 2012/2013 RPM First Incremental Auction. Unit-specific offer caps were calculated for 14 generation resources (8.6 percent of all generation resources), all of which included an APIR component. The MMU calculated offer caps for 108 generation resources (66.6 percent), of which 92 were based on the technology specific default (proxy) ACR values. Of the 162 generation resources, 17 planned generation resources had uncapped offers (10.5 percent), while the remaining 37 generation resources were price takers (22.9 percent), of which the offers for 24 generation resources were zero and the offers for 13 generation resources were set to zero because no data were submitted.

Of the 162 generation resources which submitted offers, 14 resources (8.6 percent) included an APIR component. As shown in Table 4-17, the weighted-average gross ACR for resources with APIR ($367.75 per MW-day) and the weighted-average offer caps, net of net revenues, for resources with APIR ($229.59 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 $222.35 per MW-day to the ACR value of the APIR resources. The default ACR values included an average APIR of $1.31 per MW-day. The highest APIR for a technology ($459.80 per MW-day) was for subcritical/supercritical coal units. The maximum APIR effect ($549.57 per MW-day) was the maximum amount by which an offer cap was increased by APIR.

2012/2013 RPM Second Incremental Auction

As shown in Table 4-13, 188 generation resources submitted offers in the 2012/2013 RPM Second Incremental Auction. Unit-specific offer caps were calculated for eight generation resources (4.3 percent of all generation resources), all of which included an APIR component. The MMU calculated offer caps for 91 generation resources (48.4 percent), of which 83 were based on the technology specific default (proxy) ACR values. Of the 188 generation resources, 12 Planned Generation Capacity Resources had uncapped offers (6.4 percent), three generation resources had uncapped planned uprates along with default ACR based offer caps calculated for the existing portion (1.6 percent), two generation resources had uncapped planned uprates along with price taker status for the existing portion (1.1 percent), while the remaining 83 generation resources were price takers (44.1 percent), of which the offers for 78 generation resources were zero and the offers for five generation resources were set to zero because no data were submitted.

2012/2013 RPM Third Incremental Auction

As shown in Table 4-13, 298 generation resources submitted offers in the 2012/2013 RPM Third Incremental Auction. Unit-specific offer caps were calculated for two generation resources (0.7 percent of all generation resources), all of which included an APIR component. The MMU calculated offer caps for 37 generation resources (12.4 percent), of which 35 were based on the technology specific default (proxy) ACR values. Of the 298 generation resources, 130 generation resources elected offer cap option of 1.1 times the BRA clearing price (43.6 percent), 10 Planned Generation Capacity Resources had uncapped offers (3.4 percent), two generation resources had uncapped planned uprates along with price taker status for the existing portion (0.7 percent), one generation resource had an uncapped planned uprate along with the 1.1 times the BRA clearing price option for the existing portion (0.3 percent), while the remaining 118 generation resources were price takers (39.6 percent), of which the offers for 111 generation resources were zero and the offers for 7 generation resources were set to zero because no data were submitted.

2013/2014 RPM Base Residual Auction

As shown in Table 4-14, 1,170 generation resources submitted offers in the 2013/2014 RPM Base Residual Auction. Unit-specific offer caps were calculated for 107 generation resources (9.1 percent of all generation resources offered) including 92 generation resources (7.9 percent) with an Avoidable Project Investment Recovery Rate (APIR) component and 15 generation resources (1.3 percent) without an APIR component. The MMU calculated offer caps for 700 generation resources (59.9 percent), of which 587 (50.2 percent) were based on the technology specific default (proxy) ACR values. Of the 1,170 generation resources, 20 planned generation resources had uncapped offers (1.7 percent), while the remaining 450 generation resources were price takers (38.4 percent), of which the offers for 441 generation resources were zero and the offers for nine generation resources were set to zero because no data were submitted.

Of the 1,170 generation resources which submitted offers, 92 (7.9 percent) included an APIR component. As shown in Table 4-18, the weighted-average gross ACR for resources with APIR ($390.05 per MW-day) and the weighted-average offer caps, net of net revenues, for resources with APIR ($134.44 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 $268.59 per MW-day to the ACR value of the APIR resources. The default ACR values included an average APIR of $1.37 per MW-day, which is the average APIR ($1.31 per MW-day) for the previously estimated default ACR values in the 2012/2013 BRA escalated using the most recent Handy-Whitman Index value. The highest APIR for a technology ($352.55 per MW-day) was for subcritical/supercritical coal units. The maximum APIR effect ($1,304.36 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

2013/2014 RPM First Incremental Auction

As shown in Table 4-14, 192 generation resources submitted offers in the 2013/2014 RPM First Incremental Auction. Unit-specific offer caps were calculated for 27 generation resources (14.1 percent of all generation resources), all of which included an APIR component. The MMU calculated offer caps for 104 generation resources (54.2 percent), of which 77 were based on the technology specific default (proxy) ACR values. Of the 192 generation resources, one Planned Generation Capacity Resource had an uncapped offer (0.5 percent), three generation resources had uncapped planned uprates along with default ACR based offer caps calculated for the existing portion (1.6 percent), one generation resource had an uncapped planned uprate along with price taker status for the existing portion (0.5 percent), while the remaining 86 generation resources were price takers (44.8 percent), of which the offers for 86 generation resources were zero and the offers for no generation resources were set to zero because no data were submitted.

Of the 192 generation resources which submitted offers, 27 resources (14.1 percent) included an APIR component. As shown in Table 4-18, the weighted-average gross ACR for resources with APIR ($426.53 per MW-day) and the weighted-average offer caps, net of net revenues, for resources with APIR ($160.05 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 $265.55 per MW-day to the ACR value of the APIR resources. The default ACR values included an average APIR of $1.37 per MW-day. The highest APIR for a technology ($329.36 per MW-day) was for subcritical/supercritical coal units. The maximum APIR effect ($593.49 per MW-day) was the maximum amount by which an offer cap was increased by APIR.

2013/2014 RPM Second Incremental Auction

As shown in Table 4-14, 163 generation resources submitted offers in the 2013/2014 RPM Second Incremental Auction. Unit-specific offer caps were calculated for 8 generation resources (4.9 percent of all generation resources), all of which included an APIR component. The MMU calculated offer caps for 77 generation resources (47.2 percent), of which 65 were based on the technology specific default (proxy) ACR values. Of the 163 generation resources, 11 Planned Generation Capacity Resources had uncapped offers (6.7 percent), ten generation resources had uncapped planned uprates along with default ACR based offer caps calculated for the existing portion (6.1 percent), five generation resources had uncapped planned uprates along with price taker status for the existing portion (3.1 percent), while the remaining 70 generation resources were price takers (42.9 percent), of which the offers for 69 generation resources were zero and the offers for one generation resource was set to zero because no data were submitted.

2014/2015 RPM Base Residual Auction

As shown in Table 4-15, 1,152 generation resources submitted offers in the 2014/2015 RPM Base Residual Auction. Unit-specific offer caps were calculated for 141 generation resources (12.2 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. The MOPR was applied and the MOPR exception process was applied to two units.

Of the 1,152 generation resources which submitted offers, 138 (12.0 percent) included an APIR component. As shown in Table 4-19, 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 4-19, 190 generation resources submitted offers in the 2014/2015 RPM First Incremental Auction. Unit-specific offer caps were calculated for 21 generation resources (11.1 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.

Of the 190 generation resources which submitted offers, 21 (11.1 percent) included an APIR component. As shown in Table 4-19, the weighted-average gross ACR for resources with APIR ($331.18 per MW-day) and the weighted-average offer caps, net of net revenues, for resources with APIR ($126.15 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 $123.05 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. The highest APIR for a technology ($417.50 per MW-day) was for combustion turbine (CT) units. The maximum APIR effect ($761.69 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

2015/2016 RPM Base Residual Auction

As shown in Table 4-20, 1,168 generation resources submitted offers in the 2015/2016 RPM Base Residual Auction. Unit-specific offer caps were calculated for 188 generation resources (16.1 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, of which 478 were based on the technology specific default (proxy) ACR values. Of the 1,168 generation resources, 32 Planned Generation Capacity Resources had uncapped offers, 25 generation resources had uncapped planned uprates along with default ACR based offer caps calculated for the existing portion, seven generation resources had uncapped planned uprates along with price taker status for the existing portion, while the remaining 459 generation resources 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 4-20, 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.

Market Performance[66]

Annual weighted average capacity prices increased from a CCM weighted average price of $5.73 per MW-day in 2006 to an RPM weighted-average price of $164.71 per MW-day in 2010 and then declined to $148.33 per MW-day in 2015. Figure 4-3 presents cleared MW weighted average capacity market prices on a calendar year basis for the entire history of the PJM capacity markets. Table 4-21 shows RPM clearing prices for all RPM Auctions held through the end of calendar year 2012.

As Table 4-9 shows, RPM net excess decreased 4,661.9 MW from 10,638.4 MW on June 1, 2011, to 5,976.5 MW on June 1, 2012, because of a 3,073.7 MW increase in the reliability requirement and a 5,689.3 MW net decrease considering the elimination of ILR and the implementation of the Short-Term Resource Procurement Target, offset by an 4,101.1 MW increase in cleared capacity.[67] The increase in unforced capacity of 8,003.5 MW was the result of an increase in total internal capacity of 10,070.6 MW and a decrease in exports of 521.3 MW, offset by a decrease in imports of 2,588.4 MW, primarily due to the reclassification of the Duquesne resources as internal (Table 4-4).[68]

Table 4-22 shows RPM revenue by resource type for all RPM Auctions held to date with $1.5 billion for new/reactivated generation resources based on the unforced MW cleared and the resource clearing prices.

Table 4-23 shows RPM revenue by calendar year for all RPM Auctions held to date.

66 The MMU provides detailed analyses of market performance in reports for each RPM Auction. See <http://www.monitoringanalytics.com/reports/Reports/2012.shtml>.

67 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.

68 Unforced capacity is defined as the UCAP value of iron in the ground plus the UCAP value of imports less the UCAP value of exports.

Table 4-21 Capacity prices: 2007/2008 through 2015/2016 RPM Auctions

		RPM Clearing Price ($ per MW-day)								
	Product Type	RTO	MAAC	APS	EMAAC	SWMAAC	DPL South	PSEG North	Pepco	ATSI
2007/2008 BRA		$40.80	$40.80	$40.80	$197.67	$188.54	$197.67	$197.67	$188.54	
2008/2009 BRA		$111.92	$111.92	$111.92	$148.80	$210.11	$148.80	$148.80	$210.11	
2008/2009 Third Incremental Auction		$10.00	$10.00	$10.00	$10.00	$223.85	$10.00	$10.00	$223.85	
2009/2010 BRA		$102.04	$191.32	$191.32	$191.32	$237.33	$191.32	$191.32	$237.33	
2009/2010 Third Incremental Auction		$40.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00	
2010/2011 BRA		$174.29	$174.29	$174.29	$174.29	$174.29	$186.12	$174.29	$174.29	
2010/2011 Third Incremental Auction		$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	
2011/2012 BRA		$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	
2011/2012 First Incremental Auction		$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	
2011/2012 ATSI FRR Integration Auction		$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$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
2012/2013 BRA		$16.46	$133.37	$16.46	$139.73	$133.37	$222.30	$185.00	$133.37	
2012/2013 ATSI FRR Integration Auction		$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46
2012/2013 First Incremental Auction		$16.46	$16.46	$16.46	$153.67	$16.46	$153.67	$153.67	$16.46	$16.46
2012/2013 Second Incremental Auction		$13.01	$13.01	$13.01	$48.91	$13.01	$48.91	$48.91	$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
2013/2014 BRA		$27.73	$226.15	$27.73	$245.00	$226.15	$245.00	$245.00	$247.14	$27.73
2013/2014 First Incremental Auction		$20.00	$20.00	$20.00	$178.85	$54.82	$178.85	$178.85	$54.82	$20.00
2013/2014 Second Incremental Auction		$7.01	$10.00	$7.01	$40.00	$10.00	$40.00	$40.00	$10.00	$7.01
2014/2015 BRA	Limited	$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	$225.00	$136.50	$125.99
2014/2015 BRA	Annual	$125.99	$136.50	$125.99	$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	$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	$410.95	$16.56	$5.54
2014/2015 First Incremental Auction	Annual	$5.54	$16.56	$5.54	$16.56	$16.56	$16.56	$410.95	$16.56	$5.54
2015/2016 BRA	Limited	$118.54	$150.00	$118.54	$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	$322.08
2015/2016 BRA	Annual	$136.00	$167.46	$136.00	$167.46	$167.46	$167.46	$167.46	$167.46	$357.00

Table 4-22 RPM revenue by type: 2007/2008 through 2015/2016[69,70]

Type	2007/2008	2008/2009	2009/2010	2010/2011	2011/2012	2012/2013	2013/2014	2014/2015	2015/2016	Total
Demand Resources	$5,537,085	$35,349,116	$65,762,003	$60,235,796	$55,795,785	$264,387,897	$554,697,058	$670,147,703	$880,020,384	$2,591,932,826
Energy Efficiency Resources	$0	$0	$0	$0	$139,812	$11,408,552	$21,131,133	$40,247,604	$52,113,238	$125,040,339
Imports	$22,225,980	$60,918,903	$56,517,793	$106,046,871	$185,421,273	$13,260,822	$31,738,568	$178,473,828	$186,311,568	$840,915,605
Coal existing	$1,022,372,301	$1,844,120,476	$2,417,576,805	$2,662,434,386	$1,595,707,479	$1,016,194,603	$1,738,281,395	$1,853,342,698	$2,656,149,396	$16,806,179,541
Coal new/ reactivated	$0	$0	$1,854,781	$3,168,069	$28,330,047	$7,568,127	$12,946,883	$56,917,305	$62,882,021	$173,667,234
Gas existing	$1,460,544,471	$1,911,518,321	$2,276,961,764	$2,586,971,699	$1,607,317,731	$1,079,413,451	$1,830,451,475	$1,969,632,253	$2,473,484,871	$17,196,296,036
Gas new/ reactivated	$3,472,667	$9,751,112	$30,168,831	$58,065,964	$98,448,693	$76,633,409	$167,340,901	$184,293,676	$527,114,537	$1,155,289,790
Hydroelectric existing	$209,490,444	$287,850,403	$364,742,517	$442,429,815	$278,529,660	$179,117,975	$308,773,557	$328,974,881	$384,329,997	$2,784,239,249
Hydroelectric new/reactivated	$0	$0	$0	$0	$0	$11,397	$25,708	$6,591,114	$14,880,302	$21,508,521
Nuclear existing	$996,085,233	$1,322,601,837	$1,517,723,628	$1,799,258,125	$1,079,386,338	$762,719,550	$1,346,210,480	$1,460,152,259	$1,846,030,461	$12,130,167,912
Nuclear new/ reactivated	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Oil existing	$502,172,373	$572,259,505	$715,618,319	$668,505,533	$368,084,004	$423,957,756	$685,582,719	$469,738,966	$562,402,530	$4,968,321,705
Oil new/ reactivated	$0	$4,837,523	$5,676,582	$4,339,539	$967,887	$2,772,987	$5,669,955	$3,896,120	$5,166,777	$33,327,370
Solid waste existing	$29,956,764	$33,843,188	$41,243,412	$40,731,606	$25,636,836	$26,840,670	$43,613,120	$34,529,651	$35,405,293	$311,800,540
Solid waste new/reactivated	$0	$0	$523,739	$413,503	$261,690	$316,420	$1,964,565	$1,190,758	$3,324,459	$7,995,134
Solar existing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Solar new/ reactivated	$0	$0	$0	$0	$66,978	$1,246,337	$2,720,170	$3,152,447	$3,403,067	$10,588,999
Wind existing	$430,065	$1,180,153	$2,011,156	$1,819,413	$1,072,929	$812,644	$1,373,205	$1,493,377	$1,768,330	$11,961,271
Wind new/ reactivated	$0	$2,917,048	$6,836,827	$15,232,177	$9,919,881	$5,052,036	$13,064,541	$31,173,865	$39,549,396	$123,745,769
Total	$4,252,287,381	$6,087,147,586	$7,503,218,157	$8,449,652,496	$5,335,087,023	$3,871,714,635	$6,765,585,432	$7,293,948,503	$9,734,336,627	$59,292,977,841

Table 4-23 RPM revenue by calendar year: 2007 through 2016[71]

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	$100.22	152,226.6	365	$5,568,395,048
2014	$124.72	155,428.1	365	$7,075,365,425
2015	$148.33	160,866.8	365	$8,709,157,810
2016	$161.62	164,563.9	152	$4,042,675,320

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

Figure 4-3 History of capacity prices: Calendar year 1999 through 2015[72]

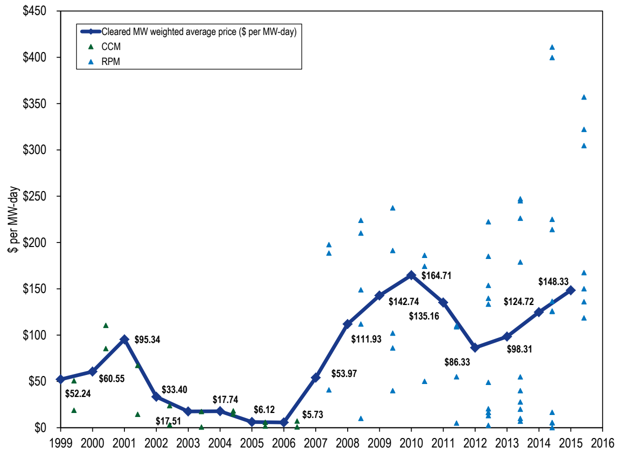


Table 4-24 shows the RPM annual charges to load. For the 2012/2013 planning year, RPM annual charges to load total approximately $3.9 billion.

Table 4-24 RPM cost to load: 2012/2013 through 2015/2016 RPM Auctions[73,74,75]

	Net Load Price ($ per MW-day)	UCAP Obligation (MW)	Annual Charges
2012/2013			
Rest of RTO	$16.74	65,495.4	$400,296,161
Rest of MAAC	$133.42	30,107.9	$1,466,181,230
Rest of EMAAC	$143.06	19,954.6	$1,041,932,095
DPL	$171.27	4,523.9	$282,806,394
PSEG	$157.73	11,645.3	$670,441,158
Total		131,727.1	$3,861,657,038
2013/2014			
Rest of RTO	$28.37	81,517.7	$844,133,053
Rest of MAAC	$232.07	14,930.2	$1,264,667,275
EMAAC	$250.12	36,738.0	$3,353,903,318
Rest of SWMAAC	$231.08	8,057.0	$679,559,435
Pepco	$244.74	7,653.2	$683,667,039
Total		148,896.1	$6,825,930,120
2014/2015			
Rest of RTO	$128.17	82,577.4	$3,863,199,144
Rest of MAAC	$137.60	30,833.8	$1,548,586,169
Rest of EMAAC	$137.61	20,460.8	$1,027,667,647
DPL	$145.32	4,625.7	$245,357,435
PSEG	$170.24	11,833.5	$735,288,837
Total		150,331.2	$7,420,099,231
2015/2016			
Rest of RTO	$134.62	84,948.0	$4,185,534,909
MAAC	$165.78	68,742.2	$4,170,968,816
ATSI	$294.03	14,940.4	$1,607,805,047
Total		168,630.6	$9,964,308,771

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 can be measured using indices calculated from historical data. Generator performance indices include those based on total hours in a period (generator performance factors) and those based on

72 1999-2006 capacity prices are CCM combined market, weighted average prices. The 2007 capacity price is a combined CCM/RPM weighted average price. The 2008-2015 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.

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

74 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.

75 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 2013/2014, 2014/2015, and 2015/2016 Net Load Prices are not finalized. The 2013/2014, 2014/2015, and 2015/2016 Obligation MW are not finalized.

hours when units are needed to operate by the system operator (generator forced outage rates).[76]

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. Nuclear units typically run at a greater than 90 percent capacity factor. In 2012, nuclear units had a capacity factor of 92.4 percent. Combined cycle units ran more often in 2012 than in the same period in 2011, increasing from a 46.0 percent capacity factor in 2011 to a 60.4 percent capacity factor in 2012. In contrast, the capacity factor for steam units decreased from 51.0 percent in 2011 to 45.5 percent in 2012.

Table 4-25 PJM capacity factor (By unit type (GWh)): 2011 and 2012[77]

	2011		2012	
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor
Battery	0.2	0.3%	0.3	0.1%
Combined Cycle	98,409.3	46.0%	136,595.3	60.4%
Combustion Turbine	5,760.3	2.3%	8,023.8	3.0%
Diesel	621.8	16.7%	592.5	15.5%
Diesel (Landfill gas)	853.5	32.9%	1,221.0	40.5%
Fuel Cell	0.0	0.0%	13.2	57.1%
Nuclear	262,968.3	91.5%	273,372.2	92.4%
Pumped Storage Hydro	6,885.7	14.3%	6,544.5	13.6%
Run of River Hydro	7,843.5	38.3%	6,105.3	28.8%
Solar	56.0	10.7%	233.5	14.3%
Steam	368,090.5	51.0%	344,755.1	45.5%
Wind	11,037.0	27.6%	12,633.6	25.7%
Total	762,526.0	48.0%	790,090.3	47.2%

Generator Performance Factors

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.

76 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.

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

The PJM aggregate EAF increased from 83.7 percent in 2011 to 84.1 percent in 2012. The EMOF increased from 3.1 percent to 3.6 percent, the EPOF decreased from 7.9 percent to 7.2 percent, and the EFOF decreased from 5.3 percent to 5.1 percent (Figure 4-4). EAF, EMOF, EPOF, and EFOF by unit type are shown in Table 4-26 through Table 4-29.

Figure 4-4 PJM equivalent outage and availability factors: 2007 to 2012

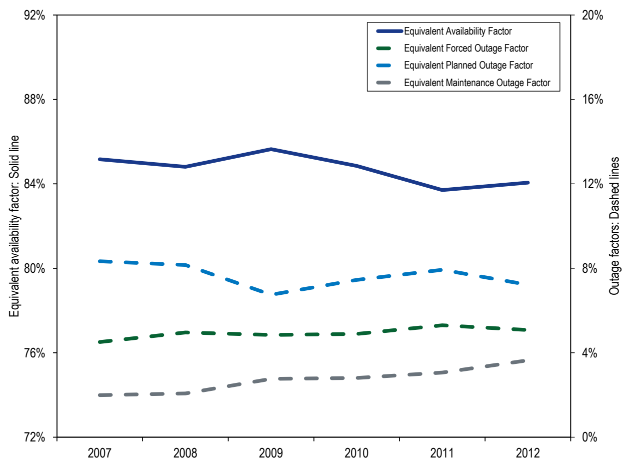


Table 4-26 EAF by unit type: 2007 through 2012

	2007	2008	2009	2010	2011	2012
Combined Cycle	88.8%	89.1%	87.8%	85.9%	85.4%	85.4%
Combustion Turbine	88.9%	89.4%	93.2%	93.1%	91.8%	92.4%
Diesel	86.5%	86.5%	91.2%	94.1%	94.8%	92.4%
Hydroelectric	90.7%	89.7%	86.9%	88.8%	84.6%	88.8%
Nuclear	93.9%	91.4%	90.1%	91.8%	90.1%	91.1%
Steam	79.2%	79.4%	80.9%	79.0%	78.2%	77.8%
Total	85.2%	84.8%	85.6%	84.8%	83.7%	84.1%

Table 4-27 EMOF by unit type: 2007 through 2012

	2007	2008	2009	2010	2011	2012
Combined Cycle	2.2%	1.7%	3.0%	3.1%	2.4%	2.9%
Combustion Turbine	2.7%	2.5%	2.3%	2.0%	2.4%	1.7%
Diesel	2.6%	1.5%	1.2%	1.5%	2.0%	2.6%
Hydroelectric	2.0%	2.3%	2.3%	1.9%	1.9%	2.1%
Nuclear	0.3%	0.5%	0.6%	0.5%	1.2%	1.1%
Steam	2.4%	2.6%	3.7%	3.9%	4.2%	5.6%
Total	2.0%	2.1%	2.8%	2.8%	3.1%	3.6%

Table 4-28 EPOF by unit type: 2007 through 2012

	2007	2008	2009	2010	2011	2012
Combined Cycle	7.3%	7.6%	6.3%	8.2%	9.7%	8.2%
Combustion Turbine	3.1%	5.1%	2.8%	3.0%	3.8%	3.2%
Diesel	0.9%	2.0%	0.6%	0.5%	0.1%	0.7%
Hydroelectric	5.7%	6.7%	8.6%	8.6%	11.8%	6.3%
Nuclear	4.7%	7.1%	5.2%	5.4%	6.1%	6.4%
Steam	11.9%	9.8%	8.6%	9.4%	9.2%	8.8%
Total	8.3%	8.2%	6.7%	7.5%	7.9%	7.2%

Table 4-29 EFOF by unit type: 2007 through 2012

	2007	2008	2009	2010	2011	2012
Combined Cycle	1.7%	1.6%	2.9%	2.7%	2.6%	3.5%
Combustion Turbine	5.3%	3.0%	1.6%	1.9%	2.0%	2.8%
Diesel	10.0%	10.0%	7.0%	3.8%	3.2%	4.2%
Hydroelectric	1.6%	1.4%	2.3%	0.7%	1.7%	2.8%
Nuclear	1.1%	1.0%	4.1%	2.3%	2.6%	1.5%
Steam	6.5%	8.2%	6.8%	7.7%	8.3%	7.8%
Total	4.5%	5.0%	4.8%	4.9%	5.3%	5.1%

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,78 service hours, average forced outage duration, average run time, average time between unit starts, available hours and period hours. The EFORd metric includes all forced outages, regardless of the reason for those outages.

Figure 4-5 shows the average EFORd since 2007 for all units in PJM.

Figure 4-5 Trends in the PJM equivalent demand forced outage rate (EFORd): 2007 through 2012

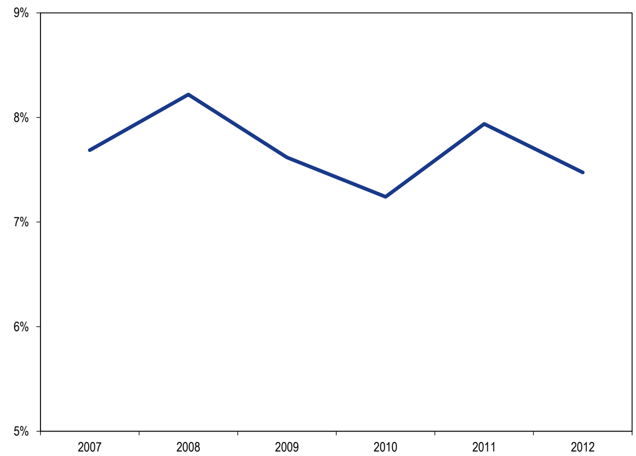


Table 4-30 shows the class average EFORd by unit type.

Table 4-30 PJM EFORd data for different unit types: 2007 through 2012

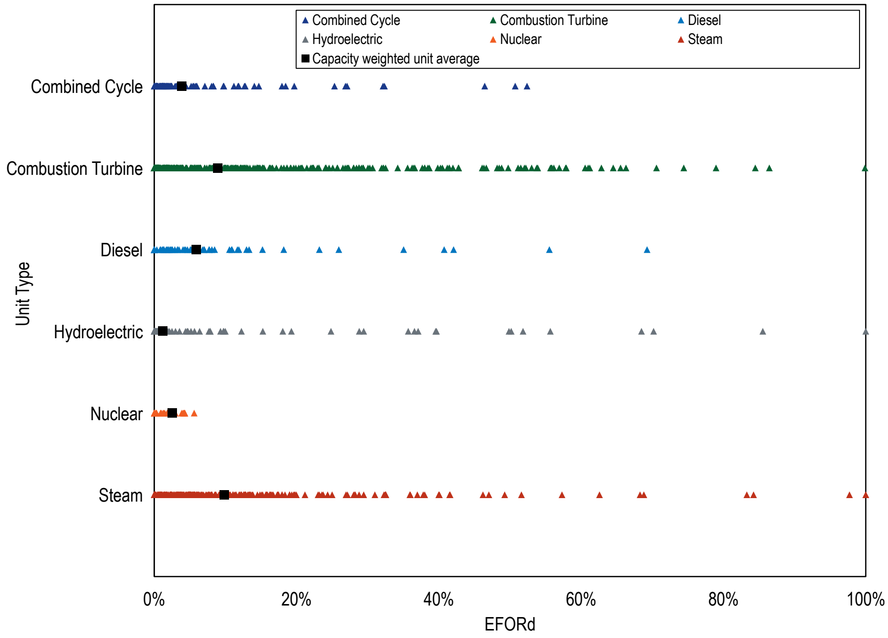
	2007	2008	2009	2010	2011	2012	NERC EFORd 2007 to 2011 Average
Combined Cycle	3.7%	3.4%	4.3%	3.8%	3.5%	4.2%	4.4%
Combustion Turbine	17.0%	14.2%	9.8%	8.9%	8.0%	8.2%	9.4%/9.7%
Diesel	11.7%	11.0%	9.9%	5.9%	9.6%	5.6%	12.5%
Hydroelectric	2.2%	2.1%	3.2%	1.2%	2.9%	4.4%	5.3%
Nuclear	1.2%	1.1%	4.1%	2.5%	2.8%	1.6%	3.1%
Steam	8.7%	10.7%	9.4%	9.8%	11.3%	10.6%	7.6%
Total	7.7%	8.2%	7.6%	7.2%	7.9%	7.5%	NA

Distribution of EFORd

The average EFORd results do not show the underlying pattern of EFORd rates by unit type. The distribution of EFORd by unit type is shown in Figure 4-6. Each generating unit is represented by a single point, and the capacity weighted unit average is represented by a solid square. Hydroelectric units had the greatest variance of EFORd, while nuclear and combined cycle units had the lowest variance in EFORd values.

78 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.

Figure 4-6 PJM 2012 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

In 2006, NERC created specifications for certain types of outages to be deemed Outside Management Control (OMC).79 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.[80] Not all outages caused

79 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>.

80 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>.

by the factors in these specific OMC cause codes are OMC outages. For example, according to the NERC specifications, fuel quality issues (codes 9200 to 9299) may be within the control of the owner or outside management control. Each outage must be considered separately per the NERC directive.

However, nothing in NERC's classification of outages requires that PJM exclude OMC outages from the forced outage rate metric used in the Capacity Market. That choice was made by PJM and can be modified without violating any NERC requirements.[81] It is possible to have an OMC outage under the NERC definition, which PJM does not define as OMC for purposes of calculating XEFORd. That is the current PJM practice. The actual implementation of the OMC outages and their impact on XEFORd is and has been within the control of PJM. PJM has chosen to exclude only some of the OMC outages from the XEFORd metric.

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

All outages, including OMC outages, are included in the EFORd that is used for PJM planning studies that determine the reserve requirement. However, OMC outages are excluded from the calculations used to determine the level of unforced capacity for specific units that must be offered in PJM's Capacity Market. This modified EFORd is termed the XEFORd. Table 4-31 shows OMC forced outages by cause code, as classified by PJM. OMC forced outages account for 12.4 percent of all forced outages. The second-largest contributor to OMC outages, lack of fuel, was the cause in 2012 of 36.9 percent of OMC outages and 4.6 percent of all forced outages. The NERC GADS guidelines in Appendix K describe OMC lack of fuel as "lack of fuel where the operator is not in control of contracts, supply lines, or delivery of fuels."

Table 4-31 OMC Outages: 2012

OMC Cause Code	Percent of OMC Forced Outages	Percent of all Forced Outages
Hurricane	42.4%	5.2%
Lack of fuel	36.9%	4.6%
Flood	6.2%	0.8%
Transmission system problems	3.7%	0.5%
Switchyard circuit breakers external	2.9%	0.4%
Other switchyard equipment external	1.9%	0.2%
Transmission line	1.2%	0.1%
Transmission equipment beyond the 1st substation	1.1%	0.1%
Storms	0.9%	0.1%
Lack of water	0.9%	0.1%
Lightning	0.8%	0.1%
Transmission equipment at the 1st substation	0.3%	0.0%
Switchyard system protection devices external	0.3%	0.0%
Other fuel quality problems	0.1%	0.0%
Other miscellaneous external problems	0.1%	0.0%
Switchyard transformers and associated cooling systems	0.1%	0.0%
Tornados	0.1%	0.0%
Poor quality natural gas fuel, low heat content	0.0%	0.0%
Total	100.0%	12.4%

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

81 It is unclear whether there were member votes taken on this issue.

distorts market outcomes. That is exactly the result of using OMC outages to reduce EFORd.[82]

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

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

The NYISO does not classify any fuel related outages or derates as OMC under its capacity market rules.[83]

It is clear that OMC outages defined as lack of fuel should not be identified as OMC and should not be excluded from the calculation of XEFORd and EFORp.

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, that 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.

Table 4-32 shows the impact of OMC outages on EFORd. The difference is especially noticeable for steam units and combustion turbine units.

Table 4-32 PJM EFORd vs. XEFORd: 2012

	EFORd	XEFORd	Difference
Combined Cycle	4.2%	3.3%	0.9%
Combustion Turbine	8.2%	5.7%	2.5%
Diesel	5.6%	5.0%	0.6%
Hydroelectric	4.4%	4.2%	0.2%
Nuclear	1.6%	1.5%	0.1%
Steam	10.6%	9.7%	0.9%
Total	7.5%	6.5%	1.0%

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

PJM EFOF was 5.1 percent in 2012. This means there was 5.1 percent lost availability because of forced outages. Table 4-33 shows that forced outages for boiler tube leaks, at 17.8 percent of the systemwide EFOF, were the largest single contributor to EFOF.

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

83 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.

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

Table 4-33 Contribution to EFOF by unit type by cause: 2012

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	System
Boiler Tube Leaks	1.8%	0.0%	0.0%	0.0%	0.0%	23.5%	17.8%
Catastrophe	25.2%	29.7%	9.7%	1.1%	2.9%	1.7%	6.2%
Boiler Piping System	2.7%	0.0%	0.0%	0.0%	0.0%	7.3%	5.7%
Feedwater System	3.8%	0.0%	0.0%	0.0%	3.9%	6.4%	5.3%
Boiler Air and Gas Systems	0.0%	0.0%	0.0%	0.0%	0.0%	6.6%	4.9%
Economic	0.2%	0.8%	0.7%	4.8%	0.0%	6.1%	4.7%
Electrical	4.0%	9.4%	3.5%	8.7%	8.3%	3.9%	4.7%
High Pressure Turbine	0.0%	0.0%	0.0%	0.0%	0.0%	5.3%	4.0%
Miscellaneous (Generator)	5.3%	4.6%	1.5%	55.7%	0.0%	2.1%	3.7%
Reserve Shutdown	2.9%	15.0%	16.2%	2.1%	1.4%	2.6%	3.6%
Boiler Fuel Supply from Bunkers to Boiler	1.2%	0.0%	0.0%	0.0%	0.0%	3.4%	2.6%
Valves	3.9%	0.0%	0.0%	0.0%	3.8%	2.6%	2.5%
Controls	2.9%	0.6%	0.7%	0.2%	4.8%	1.7%	1.8%
Reactor Coolant System	0.0%	0.0%	0.0%	0.0%	36.1%	0.0%	1.8%
Miscellaneous (Steam Turbine)	1.0%	0.0%	0.0%	0.0%	0.2%	2.2%	1.7%
Circulating Water Systems	0.8%	0.0%	0.0%	0.0%	7.6%	1.6%	1.7%
Condensing System	1.7%	0.0%	0.0%	0.0%	3.5%	1.6%	1.5%
Miscellaneous (Gas Turbine)	6.2%	9.6%	0.0%	0.0%	0.0%	0.0%	1.4%
Other Operating Environmental Limitations	0.9%	0.0%	0.0%	0.2%	3.9%	1.4%	1.3%
All Other Causes	35.5%	30.4%	67.7%	27.3%	23.6%	20.3%	22.9%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Table 4-34 shows the categories which are included in the economic category.[85] Lack of fuel that is considered Outside Management Control accounted for 96.2 percent of all economic reasons while lack of fuel that was not Outside Management Control accounted for only 1.3 percent.

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."[86] 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 4-34 Contributions to Economic Outages: 2012

	Contribution to Economic Reasons
Lack of fuel (OMC)	96.2%
Lack of water (Hydro)	2.3%
Lack of fuel (Non-OMC)	1.3%
Fuel conservation	0.2%
Other economic problems	0.0%
Ground water or other water supply problems	0.0%
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.[87] It is reasonable to expect that units have some degree of control over when to take a forced outage, depending on the underlying cause of the forced outage. If units had no control over the timing of forced outages, outages during peak hours of the peak months would be expected to occur at roughly the same rate as outages during periods of demand throughout the rest of the year. With the exception of nuclear units, EFORp is lower than EFORd, suggesting that units elect to take forced outages during off-peak hours, as much as it is

85 The classification and definitions of these outages are defined by NERC GADS.
86 The classification and definitions of these outages are defined by NERC GADS.
87 See "Manual 22: Generator Resource Performance Indices," Revision 16 (November 16, 2011), Definitions.

within their control to do so. That is consistent with the incentives created by the PJM Capacity Market.

Table 4-35 shows the capacity-weighted class average of EFORd, XEFORd and EFORp. The impact of OMC outages is especially noticeable in the difference between EFORd and XEFORd for steam units and combustion turbine units.

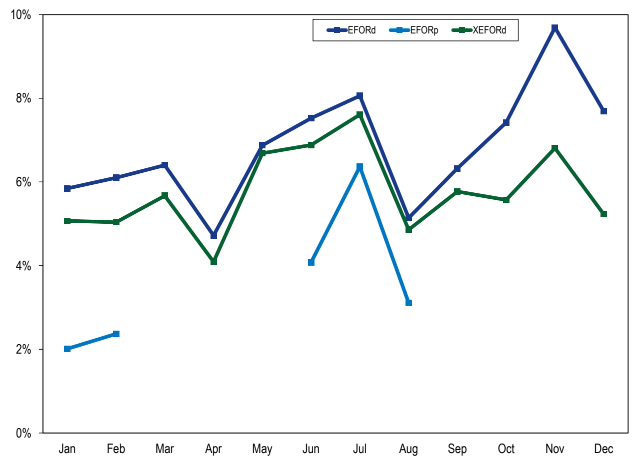
Table 4-35 PJM EFORd, XEFORd and EFORp data by unit type: 2012[88]

	EFORd	XEFORd	EFORp	Difference EFORd and XEFORd	Difference EFORd and EFORp
Combined Cycle	4.2%	3.3%	2.0%	0.9%	2.2%
Combustion Turbine	8.2%	5.7%	2.9%	2.5%	5.3%
Diesel	5.6%	5.0%	2.8%	0.6%	2.8%
Hydroelectric	4.4%	4.2%	4.9%	0.2%	(0.5%)
Nuclear	1.6%	1.5%	1.8%	0.1%	(0.2%)
Steam	10.6%	9.7%	5.7%	0.9%	4.9%
Total	7.5%	6.5%	4.0%	1.0%	3.5%

Performance By Month

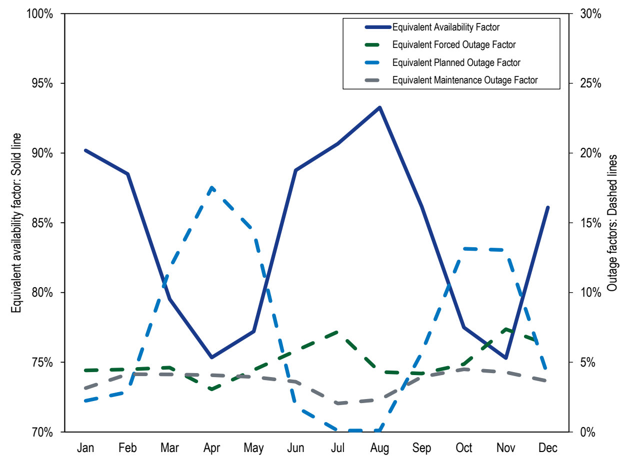
On a monthly basis, EFORp values were significantly less than EFORd and XEFORd values as shown in Figure 4-7, demonstrating that units had fewer outages during peak hours than would have been expected based on EFORd.

Figure 4-7 PJM EFORd, XEFORd and EFORp: 2012



On a monthly basis, unit availability as measured by the equivalent availability factor increased during the summer months of June, July and August, primarily due to decreasing planned and maintenance outages, as illustrated in Figure 4-8.

Figure 4-8 PJM monthly generator performance factors: 2012



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