SECTION 5 – CAPACITY MARKET

Each organization serving PJM load must meet its capacity obligations by acquiring capacity resources through the PJM Capacity Market, where load serving entities (LSEs) must pay the locational capacity price for their zone. LSEs can affect the financial consequences of purchasing capacity in the capacity market by constructing generation and offering it into the capacity market, by entering into bilateral contracts, by developing demand-side resources and Energy Efficiency (EE) resources and offering them into the capacity market, or by constructing transmission upgrades and offering them into the capacity market.

The Market Monitoring Unit (MMU) analyzed market structure, participant conduct and market performance in the PJM Capacity Market for calendar year 2010, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.

Table 5-1 The Capacity Market results were competitive

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Not Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior: Local Market	Competitive	
Market Performance	**Competitive**	**Mixed**

- The aggregate market structure was evaluated as not competitive. The entire PJM region failed the preliminary market structure screen (PMSS), which is conducted by the MMU prior to each Base Residual Auction, for every planning year for which it was completed. For all auctions held, the PJM region failed the Three Pivotal Supplier Test (TPS), which is conducted at the time of the auction.

- The local market structure was evaluated as not competitive. All modeled Locational Deliverability Areas (LDAs) failed the preliminary market structure screen (PMSS), which is conducted by the MMU prior to each Base Residual Auction, for every planning year for which it was completed. For almost every auction held, all LDAs failed the Three Pivotal Supplier Test (TPS), which is conducted at the time of the auction.

- Participant behavior was evaluated as competitive. Market power mitigation measures were applied when the capacity market seller failed the market power test for the auction and the submitted sell offer exceeded the defined offer cap.

- Market performance was evaluated as competitive. Although structural market power exists in the Capacity Market, a competitive outcome resulted from the application of market power mitigation rules.

- Market design was evaluated as mixed because while there are many positive features of the RPM design, there are several features of the RPM design which threaten competitive outcomes. These include the 2.5 percent reduction in demand in Base Residual Auctions, a definition of DR which permits an inferior product to substitute for capacity and inadequate rules to address buyer side market power.

Highlights and New Analysis

- The RTO resource clearing price in the 2010/2011 RPM Base Residual Auction increased \$72.25 per MW-day (70.8 percent) from the 2009/2010 RPM Base Residual Auction, and the RTO resource clearing price for the 2010/2011 RPM Third Incremental Auction increased \$10.00 per MW-day (25.0 percent) from the 2009/2010 RPM Third Incremental Auction.

- RPM has resulted in new resources. New generation capacity resources (5,986.1 MW), reactivated generation capacity resources (849.7 MW), uprates to existing generation capacity resources (4,905.3 MW), and the net increase in capacity imports (4,126.1 MW) totaled 15,867.2 MW since the implementation of RPM.

- The results of the 2011/2012 and 2012/2013 ATSI Integration Auctions are reported. The integration of the ATSI zone resources added 13,175.2 MW to total internal capacity. The net effect from June 1, 2010, to June 1, 2013, was an increase in total internal capacity of 25,647.3 MW (16.1 percent) from 159,030.9 MW to 184,678.2 MW.

- Capacity in the RPM load management programs increased by 1,783.3 MW from 6,899.7 MW on June 1, 2009 to 8,683.0 MW on June 1, 2010.

- 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 \$100.26 per MW-day in 2013.

- Average PJM equivalent demand forced outage rate (EFORd) decreased from 7.6 percent in 2009 to 7.2 percent in 2010.

- The PJM aggregate equivalent availability factor (EAF) decreased from 85.7 percent in 2009 to 84.8 percent in 2010. The equivalent maintenance outage factor (EMOF) increased from 2.8 percent in 2009 to 2.9 percent in 2010, the equivalent planned outage factor (EPOF) increased from 6.7 percent in 2009 to 7.4 percent in 2010, and the equivalent forced outage factor (EFOF) increased from 4.8 percent in 2009 to 4.9 percent in 2010.

Summary Recommendations

- The MMU recommends that the RPM market structure, definitions and rules be modified to improve the efficiency of market prices and to ensure that market prices reflect the forward locational marginal value of capacity.

- The MMU recommends that the obligations of capacity resources be more clearly defined in the market rules.

- The MMU recommends that the performance incentives in the RPM Capacity Market design be strengthened.

- The MMU recommends that the terms of Reliability Must Run (RMR) service be reviewed, refined and standardized.

Overview

RPM Capacity Market

Market Design

The Reliability Pricing Model (RPM) Capacity Market design was implemented in the PJM region on June 1, 2007.[1] The RPM is a forward-looking, annual, locational market, with a must offer requirement for capacity and mandatory participation by load, with performance incentives for generation, that includes clear, market power mitigation rules and that permits the direct participation of demand-side resources.

Under RPM, capacity obligations are annual. Base Residual Auctions (BRA) are held for delivery years that are three years in the future. Effective with the 2012/2013 delivery year, First, Second and Third Incremental Auctions (IA) are held for each delivery year.[2] Prior to the 2012/2013 delivery year, the Second Incremental Auction is conducted if PJM determines that an unforced capacity resource shortage exceeds 100 MW of unforced capacity due to a load forecast increase. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[3] Previously, First, Second, and Third Incremental Auctions were conducted 23, 13, and four months, respectively, prior to the delivery year. Also effective for the 2012/2013 delivery year, a conditional incremental auction may be held if there is a need to procure additional capacity resulting from a delay in a planned large transmission upgrade that was modeled in the BRA for the relevant delivery year.[4]

RPM prices are locational and may vary depending on transmission constraints.[5] Existing generation capable of qualifying as a capacity resource must be offered into RPM Auctions, except for resources owned by entities that elect the fixed resource requirement (FRR) option. Participation by LSEs is mandatory, except for those entities that elect the FRR option. There is an administratively determined demand curve that defines scarcity pricing levels and that, with the supply curve derived from capacity offers, determines market prices in each BRA. RPM rules provide performance incentives for generation, including the requirement to submit generator outage data and the linking of capacity payments to the level of unforced capacity. Under RPM there are explicit market power mitigation rules that define the must offer requirement, that define structural market power, that define offer caps based on the marginal cost of capacity and that have flexible criteria for competitive offers by new entrants or by entrants that have an incentive to exercise monopsony power. Demand-side resources and Energy Efficiency resources may be offered directly into RPM auctions and receive the clearing price without mitigation.

1 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in the *2010 State of the Market Report for PJM*, Section 5, "Capacity Market" and include all capacity within the PJM footprint.
2 See 126 FERC ¶ 61,275 (2009) at P 86.
3 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).
4 See 126 FERC ¶ 61,275 (2009) at P 88.
5 Transmission constraints are local capacity import capability limitations (low capacity emergency transfer limit (CETL) margin over capacity emergency transfer objective (CETO)) caused by transmission facility limitations, voltage limitations or stability limitations.

Market Structure

- **Supply.** Total internal capacity increased 1,712.7 MW from 157,318.2 MW on June 1, 2009, to 159,030.9 MW on June 1, 2010.[6] This increase was the result of 406.9 MW of new generation, 165.0 MW that came out of retirement, 1,085.8 MW of net generation capacity modifications (cap mods), 43.7 MW of demand resource (DR) modifications (mods), and an increase of 11.3 MW due to lower equivalent demand forced outage rates (EFORds).

  In the 2011/2012, 2012/2013, and 2013/2014 auctions, new generation increased 3,969.4 MW; 486.9 MW came out of retirement and net generation cap mods were -2043.5 MW, for a total of 2,412.8 MW. DR and Energy Efficiency (EE) modifications totaled 11,360.5 MW through June 1, 2013. A decrease of 1,481.8 MW was due to higher EFORds. The classification of the Duquesne resources as external reduced total internal capacity by 3,006.6 MW, and the reclassification of the Duquesne resources as internal added 3,187.2 MW to total internal capacity. The integration of the ATSI zone resources added 13,175.2 MW to total internal capacity. The net effect from June 1, 2010, to June 1, 2013, was an increase in total internal capacity of 25,647.3 MW (16.1 percent) from 159,030.9 MW to 184,678.2 MW.

  In the 2010/2011 auction, 11 more generation resources made offers than in the 2009/2010 RPM auction. The increase consisted of 15 new resources (406.9 MW), four reactivated resources (161.7 MW), three that were previously entirely FRR committed (10.9 MW), one less resource excused from offering (3.9 MW), and one less resource entirely exported (39.9 MW), offset by four deactivated resources (59.6 MW), four resources exported from PJM (554.0 MW), three retired resources (348.4 MW), and two resources excused from offering (108.8 MW). The new generation capacity resources consisted of seven new combustion turbine (CT) resources (270.5 MW), five new wind resources (120.0 MW), three new diesel resources (16.4 MW), and four reactivated resources (165.0 MW).

  In the 2011/2012 auction, 21 more generation resources made offers than in the 2010/2011 RPM auction. The increase consisted of 20 new resources (2,203.7 MW), four reactivated resources (486.9 MW), three fewer excused resources (126.3 MW), and one additional resource imported (663.2 MW), offset by five additional resources committed fully to FRR (1.0 MW) and two retired resources (87.3 MW). The new generation capacity resources consisted of 11 new CT resources (728.7 MW), four new wind resources (75.2 MW), two new steam resources (838.0 MW), one new combined cycle resource (556.5 MW), one new diesel resource (4.2 MW) and one new solar resource (1.1 MW).

  In the 2012/2013 auction, eight more generation resources made offers than in the 2011/2012 RPM auction. The net increase of eight 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).[7] In addition, there were the following retirements of resources

6 Unless otherwise specified, all volumes are in terms of unforced capacity (UCAP).

7 Disaggregation and aggregation of RPM resources reflect changes in how units are offered in RPM. For example, multiple units at a plant may be offered as a single unit or multiple units.

that were either exported or excused in the 2011/2012 BRA: two CT 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 resources (521.5 MW) in the RTO. The new generation capacity 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).

In the 2013/2014 auction, 37 more generation resources made offers than in the 2012/2013 auction. The increase in 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 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).

- **Demand.** There was a 3,156.7 MW increase in the RPM reliability requirement from 153,480.1 MW on June 1, 2009 to 156,636.8 MW on June 1, 2010. On June 1, 2010, PJM Electric Distribution Companies (EDCs) and their affiliates maintained a 77.7 percent market share of load obligations under RPM, down from 79.6 percent on June 1, 2009.

- **Market Concentration.** For the 2010/2011, 2011/2012, 2012/2013, and 2013/2014 RPM Auctions, all defined markets failed the preliminary market structure screen (PMSS). In the 2010/2011 BRA, 2010/2011 Third Incremental Auction, 2011/2012 BRA, 2011/2012 First Incremental Auction, 2011/2012 ATSI Integration Auction, 2012/2013 First Incremental Auction, 2012/2013 ATSI Integration Auction, and 2013/2014 BRA all participants in the total PJM market as well as the locational deliverability area (LDA) markets failed the three pivotal supplier (TPS) market structure test. 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. Six participants included in the incremental supply of EMAAC passed the TPS test. Offer caps were applied to all sell offers for resources which were subject to mitigation submitted by capacity market sellers that did not pass the test.[8,9,10]

- **Imports and Exports.** Net exchange decreased 707.2 MW from June 1, 2009 to June 1, 2010. Net exchange, which is imports less exports, decreased due to an increase in exports of 952.5 MW offset by an increase in imports of 245.3 MW.

8 OATT Attachment DD (Reliability Pricing Model) § 6.5.

9 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.

10 The definition of planned generation capacity resource and the rules regarding mitigation were redefined effective January 31, 2011. See 134 FERC ¶ 61,065 (2011).

- **Demand-Side and Energy Efficiency Resources.** Under RPM, demand-side resources in the Capacity Market increased by 1,783.3 MW from 6,899.7 MW on June 1, 2009 to 8,683.0 MW on June 1, 2010. Demand-side resources include demand resources and energy efficiency 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.[11]

- **RPM Net Excess.**[12] RPM net excess decreased 537.5 MW from 8,265.5 MW on June 1, 2009 to 7,728.0 MW on June 1, 2010.

Market Conduct

- **2010/2011 RPM Base Residual Auction.**[13] Of the 1,104 generation resources which submitted offers, unit-specific offer caps were calculated for 154 resources (13.9 percent). Offer caps of all kinds were calculated for 532 resources (48.1 percent), of which 370 were based on the technology specific default (proxy) ACR values.

- **2010/2011 Third Incremental Auction.**[14] Of the 303 generation resources which submitted offers, 193 resources elected the offer cap option of 1.1 times the BRA clearing price (63.7 percent). Unit-specific offer caps were calculated for one resource (0.3 percent). Offer caps of all kinds were calculated for nine resources (2.9 percent), of which seven were based on the technology specific default (proxy) ACR values.

- **2011/2012 RPM Base Residual Auction.**[15] Of the 1,125 generation resources which submitted offers, unit-specific offer caps were calculated for 145 resources (12.9 percent). Offer caps of all kinds were calculated for 470 resources (41.8 percent), of which 301 were based on the technology specific default (proxy) ACR values.

- **2011/2012 RPM First Incremental Auction.**[16] Of the 129 generation resources which submitted offers, unit-specific offer caps were calculated for 19 resources (14.7 percent). Offer caps of all kinds were calculated for 68 resources (52.8 percent), of which 47 were based on the technology specific default (proxy) ACR values.

- **2011/2012 ATSI Integration Auction.**[17] Of the 141 generation resources which submitted offers, 52 resources elected the offer cap option of 1.1 times the BRA clearing price (36.9

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

12 Prior to the 2012/2013 delivery year, net excess under RPM was calculated as cleared capacity less the reliability requirement plus ILR. For 2007/2008 through 2010/2011, certified ILR was used in the calculation. Forecast ILR less FRR DR is used in the calculation when ILR was not certified and prior to 2011/2012 because PJM forecast ILR including FRR DR for the first four Base Residual Auctions. PJM forecast ILR excluding FRR DR for 2011/2012, so FRR DR is not subtracted in the calculation for 2011/2012. Net excess calculations for auctions prior to 2010/2011 were originally calculated as cleared capacity less the reliability requirement. For delivery years 2012/2013 and beyond, net excess under RPM is calculated as cleared capacity less the reliability requirement plus the Short-Term Resource Procurement Target.

13 For a more detailed analysis of the 2010/2011 RPM Base Residual Auction, see "Analysis of the 2010-2011 RPM Auction Revised" (July 3, 2008) <http://www.monitoringanalytics.com/reports/Reports/2008/20102011-rpm-review-final-revised.pdf>.

14 For a more detailed analysis of the 2010/2011 RPM Third Incremental Auction, see "Analysis of the 2010/2011 RPM Third Incremental Auction" (December 20, 2010) <http://www.monitoringanalytics.com/reports/Reports/2010/Analysis_of_2010_2011_RPM_Third_Incremental_Auction_20101220.pdf>.

15 For a more detailed analysis of the 2011/2012 RPM Base Residual Auction, see "Analysis of the 2011/2012 RPM Auction Revised" (October 1, 2008) <http://www.monitoringanalytics.com/reports/Reports/2008/20081002-review-of-2011-2012-rpm-auction-revised.pdf>.

16 For a more detailed analysis of the 2011/2012 RPM First Incremental Auction, see "Analysis of the 2011/2012 RPM First Incremental Auction" (January 6, 2011) <http://www.monitoringanalytics.com/reports/Reports/2011/Analysis_of_2011_2012_RPM_First_Incremental_Auction_20110106.pdf>.

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

percent). Unit-specific offer caps were calculated for four resources (2.8 percent). Offer caps of all kinds were calculated for 64 resources (45.3 percent), of which 57 were based on the technology specific default (proxy) ACR values.

- **2012/2013 RPM Base Residual Auction.**[18] Of the 1,133 generation resources which submitted offers, unit-specific offer caps were calculated for 120 resources (10.6 percent). Offer caps of all kinds were calculated for 607 resources (53.6 percent), of which 479 were based on the technology specific default (proxy) ACR values.

- **2012/2013 ATSI Integration Auction.**[19] 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). Offer caps of all kinds were calculated for 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). Offer caps of all kinds were calculated for 108 resources (66.6 percent), of which 92 were based on the technology specific default (proxy) ACR values.

- **2013/2014 RPM Base Residual Auction.**[20] Of the 1,170 generation resources which submitted offers, unit-specific offer caps were calculated for 107 resources (9.1 percent). Offer caps of all kinds were calculated for 700 resources (59.9 percent), of which 587 were based on the technology specific default (proxy) ACR values.

Market Performance

2010/2011 RPM Base Residual Auction

- **RTO.** Total internal RTO unforced capacity of 159,030.9 MW includes all generation resources and DR that qualified as a PJM capacity resource for the 2010/2011 RPM Base Residual Auction, excludes external units and reflects owners' modifications to installed capacity (ICAP) ratings. After accounting for FRR committed resources and imports, RPM capacity was 137,360.7 MW. The 132,190.4 MW of cleared resources for the entire RTO represented a reserve margin of 16.5 percent, resulted in net excess of 7,728.0 MW over the reliability requirement of 132,698.8 MW (Installed Reserve Margin (IRM) of 15.5 percent), and resulted in a clearing price of $174.29 per MW-day.

  Total cleared resources in the RTO were 132,190.4 MW which resulted in a net excess of 7,728.0 MW, a decrease of 537.5 MW from the net excess of 8,265.5 MW in the 2009/2010 RPM BRA. Certified interruptible load for reliability (ILR) was 8,236.4 MW.

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

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

20 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" (September 20, 2010) <http://www.monitoringanalytics.com/reports/Reports/2010/Analysis_of_2013_2014_RPM_Base_Residual_Auction_20090920.pdf>.

Cleared capacity resources across the entire RTO will receive a total of $8.4 billion based on the unforced MW cleared and the prices in the 2010/2011 RPM BRA, an increase of approximately $960.4 million from the 2009/2010 BRA.

- **DPL South.** Total internal DPL South unforced capacity of 1,546.1 MW includes all generation resources and DR that qualified as a PJM capacity resource, excludes external units and reflects owners' modifications to ICAP ratings. All imports offered into the auction are modeled in the RTO, so total DPL South RPM unforced capacity was 1,546.1 MW.[21] All of the 1,519.7 MW cleared in DPL South were cleared in the RTO before DPL South became constrained. Of the 26.4 MW of incremental supply, none cleared, because all 26.4 MW were priced above the demand curve. The DPL South resource clearing price of $186.12 per MW-day was determined by the intersection of the demand curve and a vertical section of the supply curve.

  Total resources in DPL South were 2,966.7 MW, which when combined with certified ILR of 97.2 MW resulted in a net excess of 14.5 MW (0.5 percent) greater than the reliability requirement of 3,049.4 MW.

2010/2011 RPM Third Incremental Auction

- **RTO.** There were 4,553.9 MW offered into the 2010/2011 Third Incremental Auction while buy bids totaled 5,221.0 MW. Cleared volumes in the RTO were 1,845.8 MW, resulting in an RTO clearing price of $50.00 per MW-day. The 2,708.1 MW of uncleared volumes can be used as replacement capacity or traded bilaterally.

  Cleared capacity resources across the entire RTO will receive a total of $33.7 million based on the unforced MW cleared and the prices in the 2010/2011 RPM Third Incremental Auction.

- **DPL South.** Although DPL South was a constrained LDA in the 2010/2011 BRA, supply and demand curves resulted in a price less than the RTO clearing price. The result was that all of DPL South supply which cleared received the RTO clearing price. Supply offers in the incremental auction in DPL South (56.8 MW) exceeded DPL South demand bids (25.9 MW).

Generator Performance

- **Forced Outage Rates.** Average PJM EFORd decreased from 7.6 percent in 2009 to 7.2 percent in 2010. PJM Peak-Period Equivalent Forced Outage Rate Peak (EFORp) increased from 4.0 percent in 2009 to 5.2 percent in 2010.[22]

- **Generator Performance Factors.** The PJM aggregate equivalent availability factor decreased from 85.7 percent in 2009 to 84.8 percent in 2010.

21 Rules for RPM auctions state that imports are modeled in the unconstrained region of the RTO. See PJM. "Manual 18: PJM Capacity Market," Revision 10 (June 1, 2010), p. 24.

22 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. Data is for the calendar year ending December 31, as downloaded from the PJM GADS database on January 21, 2011. Annual 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.

- **Outages Deemed Outside Management Control (OMC).** According to NERC criteria, an outage may be classified as an OMC outage only if the generating unit outage was caused by other than failure of the owning company's equipment or other than the failure of the practices, policies and procedures of the owning company. 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

Capacity Market Design and Scarcity Revenues

The wholesale power markets, in order to be viable, must be competitive and they must provide adequate revenues to ensure an incentive to invest in new capacity. A wholesale energy market will not consistently produce competitive results in the absence of local market power mitigation rules. This is the result, not of a fundamental flaw in the market design, but of the fact that transmission constraints in a network create local markets where there is structural market power. A wholesale energy market will not consistently result in adequate revenues in the absence of a carefully designed and comprehensive approach to scarcity pricing. This is a result, not of offer capping, but of the fundamentals of wholesale power markets which must carry excess capacity in order to meet externally imposed reliability rules.

Scarcity revenues to generation owners can come entirely from energy markets or they can come from a combination of energy and capacity markets. The RPM design reflects the recognition that the energy markets, by themselves and in the absence of a carefully designed expansion of scarcity pricing, will not result in adequate revenues. The RPM design provides an alternate method for collecting scarcity revenues. The revenues in the capacity market are scarcity revenues.

The Definition of Capacity

In order for capacity markets to work, it is essential that the product definition be correct.

The definition of the capacity product is central to refining the market rules governing the sale and purchase of capacity. The current definition of capacity includes several components: the obligation to offer the energy of the unit into the Day-Ahead Energy Market; the obligation to permit PJM to recall the energy from the unit under emergency procedures; the obligation to provide outage data to PJM; the obligation to provide energy during the defined high demand hours each year; the obligation that the energy output from the resource be deliverable to load in PJM; and the obligation to test generation net capability.

The most critical of these components of the definition of capacity is the obligation to offer the energy of the unit into the Day-Ahead Energy Market. If buyers are to pay the high prices associated with RPM, it must be clear what they are buying and what the obligations of the sellers are. The fundamental energy market design should assure all market participants that the outcomes are competitive. This works to the ultimate advantage of all market participants including existing and prospective load and existing and prospective generation. The market rules should explicitly require that offers into the Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units. The short run marginal cost should reflect opportunity cost when and where appropriate.

An offer that exceeds short run marginal cost is not a competitive offer in the Day-Ahead Energy Market. Such an offer assumes the need to exercise market power to ensure revenue adequacy. An offer to provide energy only in an emergency is not a competitive offer in the Day-Ahead Energy Market. A unit which is not capable of supplying energy consistent with its day-ahead offer should reflect an appropriate outage rather than indicating its availability to supply energy on an emergency basis.

The obligation to offer energy in the Day-Ahead Energy Market should be applied without exception to all capacity resources, including both generation and demand resources. This means that capacity resources must be available every hour of the year at a competitive price. Demand resources that agree to interrupt only 10 times per year for a maximum of six hours per interruption should not be considered capacity resources. Generation resources that agree to provide an energy offer only under PJM emergency conditions should not be considered capacity resources. Generation resources that agree to provide energy only when the price is extremely high (and greater than the short run marginal cost of such units) should not be considered capacity resources. The only exception, and it is not really an exception, is that units which have a legitimate short term emergency condition, may appropriately offer the relevant portion of the unit as an emergency resource.

Capacity resources are required to ensure the reliability of the system. Reliability is not defined as the operation of the system only during an emergency but the reliable operation of the system in every hour of the year. If the system reserve margin were comprised of demand resources that would only interrupt 10 times for a maximum of six hours or generation resources that would only perform during an emergency or generation that will only perform when the price is $999 per MWh, the probability of needing those resources would increase significantly and the number of hours during which those resources are needed would increase significantly. As a general matter, the probability of needing such resources increases with the level of such resources that are defined to be capacity and thus needed for reliability.

The actual dispatch of resources in the energy market should be a function of the marginal cost to produce energy for each resource and not based on the refusal of a resource to make a competitive offer. Net revenues from the energy market, the ancillary services markets and the capacity market are the market based compensation. Investment decisions result from this total compensation.

The sale of capacity is also the sale of recall rights to the energy from capacity resources during an emergency. Regardless of where the energy from a unit is sold, it must be recallable by PJM when PJM is in an emergency condition or a scarcity condition. PJM does not have clear protocols for recalling the energy output of capacity resources and has not recalled such energy since 1999, despite the fact that PJM has experienced emergency conditions since that time.

Capacity Prices and the Structure of Capacity Auctions

If capacity markets are to work to provide incentives for maintaining existing generation and building new generation, capacity market prices must reflect actual, local supply and demand conditions. For example, getting the price a little too low at the margin could result in undermining the incentives exactly where they need to be clear. If the prices are too low as a result of the market design, this would mean that the capacity market is a mechanism for transferring wealth rather than a functioning market providing market based incentives.

Capacity auctions must be mandatory for both load and generation, if they are to work. In PJM, load has a must bid requirement, which is enforced through the use of a system demand curve and the allocation of total capacity costs to all load. In PJM, generation capacity resources have a must offer requirement, which means that all existing generation capacity resources must offer into the capacity auctions unless they have a contract with an entity outside PJM or are physically unable to perform or are committed to an FRR entity.

The must bid and must offer requirements must extend to all resources. Thus, there should be no reduction of demand on the bid side. The current 2.5 percent reduction in the demand curve, to provide for short term resources, distorts the market price. The reduction in demand results in a price lower than the competitive level thus reducing the incentives to both new and existing generation. There should be no reductions in the demand for capacity, which should reflect all capacity needed to provide reliability. In addition, the limited definition of the DR product means that an inferior product is offered in the same auction as capacity and significantly affects the clearing prices. The DR product should be defined to require unlimited interruptions.

The three year forward auction was implemented in order to provide the potential for new resources to compete with existing resources and to provide an incentive for such new entry. The prior capacity credit structure did not provide for either. The three year forward structure creates both opportunity and risks. A new generation unit that offers into an auction for a delivery year three years in the future is taking the risk that the unit will not be completed, that its costs will exceed its estimates or that the clearing price will be lower than anticipated in the first or subsequent years. Demand resources also face both opportunities and risks in a three year forward auction. A demand resource that is offered into an auction for a delivery year three years in the future is taking the risk that the customer with the demand side resource will no longer exist, that its costs will exceed its estimates or that the clearing price will be lower than anticipated in the first or subsequent years. There is nothing unique about demand resources that requires a shorter lead time or that requires distorting the market design. The fact that some generation resources or demand resources can be developed in less than three years is not a reason to distort the market design. It would be possible to shorten the time frame of the auctions for all participants but at the cost of reducing competition from new generation projects.

The market design goal is to ensure that out of market payments do not permit offers at less than competitive prices, including zero, which suppress the market clearing prices. All generation should be offered in to the auctions at no less than and no more than competitive prices and receive capacity credit if cleared and not receive capacity credit if not cleared.

Locational Prices

Capacity prices must reflect local supply and demand conditions. If capacity cannot be delivered into an area as a result of transmission constraints, a local market exists and capacity market prices should reflect the local market conditions. The CETL/CETO analysis currently used by PJM to define local markets in combination with consideration of local supply and demand is not adequate to define local markets in RPM. For example, if a unit does not clear in an RPM auction and makes an economic decision to retire but is then informed by PJM that it is needed for reliability, this is evidence that the market is not working because the local market is not properly defined. PJM determinations that a unit is needed for reliability are based on a more detailed analysis than the CETL/CETO analysis. PJM should perform such a more detailed reliability analysis of all at risk units, including all units that do not clear in RPM auctions and units that face significant investment requirements due, for example, to environmental requirements. If such units are needed for reliability, this could result in the definition of additional LDAs to reflect the actual reliability requirements of the system. Accurate locational pricing also requires that generation owners make offers that reflect their legitimate investment requirements. For example, units that will be forced to retire by environmental regulators unless they make defined investments in new technology should reflect the costs of that investment in their capacity market offer. That is essential to the functioning of the forward looking capacity market.

Capacity Markets and Incentives

If the revenues collected in the RPM market are adequate, it is not essential that a scarcity pricing mechanism exist in the energy market. Nonetheless, it would be preferable to also have a scarcity pricing mechanism in the energy market because it provides direct, hourly market-based incentives to load and generation, as long as it is designed to ensure that scarcity revenues directly offset RPM revenues. This hybrid approach would include both a capacity market and scarcity pricing in the energy market.

Capacity market design should reflect the fact that the capacity market is a mechanism for the collection of scarcity revenues and thus reflect the incentive structure of energy markets to the maximum extent possible. For example, if a generation unit does not produce power during a high price hour, it receives no revenues from the energy market. It does not receive some revenues simply for existing; it receives zero revenues. The reason that the unit does not produce energy is not relevant. It does not receive revenues if it does not produce energy even if the reason for non performance is outside management's control. That is the basic performance incentive structure of energy markets. The same performance incentive structure should be replicated in capacity market design. If a unit that is a capacity resource does not produce energy during the 500 hours defined as critical in RPM, it will receive no energy revenues for those hours. If a unit defined as a capacity resource does not produce energy when called upon during any of the hours defined as critical, it should receive no capacity revenues. This approach to performance is also consistent with the reduction or elimination of administrative penalties associated with failure to meet capacity tests, for example.

A hybrid market design can provide scarcity revenues both via scarcity pricing in the energy market and via the capacity market. However, if there is scarcity pricing in the energy market, the market design must ensure that units receiving scarcity revenues in the capacity market do not also receive scarcity revenues in the energy market. This would be double payment of scarcity revenues. This offset must reflect the actual scarcity revenues and not those reflected in forward curves or forecasts, or those reflected in results from prior years. Scarcity revenues are episodic and unlikely to be fully reflected in historical data or in forward curves, even if such curves were based on a liquid market three years forward, which they are not, and reflected locational results, which they do not. The most straightforward way to ensure that such double payment does not occur would be to ensure that capacity resources do not receive scarcity revenues in the energy market in the first place. The settlements process can remove any scarcity revenues from payments to capacity resources and eliminate the need for a complex, uncertain, after the fact procedure for offsetting scarcity revenues in the capacity market.

Market Power

The RPM Capacity Market design explicitly addresses the underlying issues of ensuring that competitive prices can reflect local scarcity while not relying on the exercise of market power to achieve the design objective, and of explicitly limiting the exercise of market power.

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

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

RPM has explicit market power mitigation rules designed to permit competitive, locational capacity prices while limiting the exercise of market power. The RPM construct is consistent with the appropriate market design objectives of permitting competitive prices to reflect local scarcity conditions while explicitly limiting market power. The RPM Capacity Market design provides that competitive prices can reflect locational scarcity while not relying on the exercise of market power to achieve that design objective by limiting the exercise of market power via the application of the three pivotal supplier test.

Competitive prices are the lowest possible prices, consistent with the resource costs. But, competitive prices are not necessarily low prices. In the Capacity Market, it is essential that the cost of new entry (CONE) be based on the actual resource costs of bringing a new capacity resource into service, including realistic interconnection costs. If RPM is to provide appropriate incentives for new entry, the marginal price signal must reflect the actual cost of new entry.

The existence of a capacity market that links payments for capacity to the level of unforced capacity and therefore to the forced outage rate creates an incentive to improve forced outage rates. The performance incentives in the RPM Capacity Market design need to be strengthened. The energy market also provides incentives for improved performance with somewhat different characteristics. Generators want to maximize their sales of energy when prices are high and if they are successful, this will also result in lower forced outage rates. Well designed scarcity pricing could also provide strong, complementary incentives for reduced outages during high load periods. It would be preferable to rely on strong market-based incentives for capacity resource performance rather than the current structure of penalties, which has its own incentive effects.

Barriers to Entry

Competitive outcomes in the capacity market can be prevented by barriers to entry. There are a variety of possible barriers to entry into the capacity market that may affect the frequency and level of entry and thus market outcomes. Such potential barriers include control of sites based on historical utility and regulatory practices; environmental rules; the costs and uncertainty associated with the transmission interconnection process and control over the timing and details of the required studies; and the uncertainty created by the PJM transmission planning process.

These and other barriers to entry should be addressed in a timely manner in order to help ensure that the capacity market will result in the entry of new capacity to meet the needs of PJM market participants. The uncertainty and resultant risks should be reflected in the cost of new entry used to establish the capacity market demand curve in RPM.

Detailed Recommendations

- The MMU recommends that the RPM market structure, definitions and rules be modified to improve the efficiency of market prices and to ensure that market prices reflect the forward locational marginal value of capacity.
  - The MMU recommends that the Short-Term Resource Procurement Target (2.5 percent demand offset) be eliminated.
  - The MMU recommends that the definition of demand side capacity (Demand Response (DR)) resources be made comparable to generation capacity resources to ensure that all resources provide the same value in the capacity market. The DR product should be defined to require unlimited interruptions. FERC recently accepted PJM's proposal on this issue.
  - The MMU recommends that there be an explicit market power test for the RPM Incremental Auctions related to market power on the buyer side. PJM has made a filing with FERC to address this issue.
  - The MMU recommends that barriers to entry be addressed in a timely manner in order to help ensure that the capacity market will result in the entry of new capacity to meet the needs of PJM market participants and reflect the uncertainty and resultant risks in the cost of new entry used to establish the capacity market demand curve in RPM. PJM is addressing some of these barriers to entry.

- The MMU recommends that the test for determining modeled Locational Deliverability Areas in RPM be redefined. A detailed reliability analysis of all at risk units should be included in the redefined model.

- The MMU recommends that PJM use the most current Handy-Whitman Index value to recalculate the ACR for the applicable year and update the ten year annual average Handy-Whitman Index value to recalculate the subsequent default ACR values.

- The MMU recommends that the cap on the amount of FRR sales into the RPM market be eliminated as a non-competitive barrier to entry.

- The MMU recommends that the obligations of capacity resources be more clearly defined in the market rules.

  - The MMU recommends that there be an explicit requirement that capacity unit offers into the Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units.

  - The MMU recommends that protocols be defined for recalling the energy output of capacity resources when PJM is in an emergency condition. PJM is developing these protocols.

  - The MMU recommends that a unit which is not capable of supplying energy consistent with its day-ahead offer should reflect an appropriate outage rather than indicating its availability to supply energy on an emergency basis.

  - The MMU recommends that PJM review all requests for Out of Management Control (OMC) carefully, develop a transparent set of rules governing the designation of outages as OMC and post those guidelines. The MMU also recommends that PJM consider eliminating lack of fuel as an acceptable basis for an OMC outage.

- The MMU recommends that the performance incentives in the RPM Capacity Market design be strengthened. The MMU recommends that capacity resources be paid on the basis of whether they produce energy when called upon during any of the hours defined as critical.

- The MMU recommends that the terms of Reliability Must Run (RMR) service be reviewed, refined and standardized. The MMU recommends that RMR agreements should limit ratepayers' obligations to the costs that the unit owner would not have incurred if the unit owner had deactivated its unit as it proposed.

Results

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

The MMU found serious market structure issues, measured by the three pivotal supplier test results, by market shares and by Herfindahl-Hirschman Index (HHI), but no exercise of market power in the PJM Capacity Market in calendar year 2010. 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 calendar year 2010.

The MMU has also identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[23,24,25,26,27,28,29]

RPM Capacity Market

Market Design

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

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.[30] In calendar year 2010, the 2013/2014 BRA was held in May, a Third Incremental Auction was held in January for the delivery year 2010/2011, ATSI FRR Integration Auctions were held in March for the delivery years 2011/2012 and 2012/2013, and a First Incremental Auction was held in September for the delivery year 2012/2013.[31]

Market Structure

Supply

As shown in Table 5-2, total internal capacity increased 1,712.7 MW from 157,318.2 MW on June 1, 2009, to 159,030.9 MW on June 1, 2010. This increase was the result of 406.9 MW of new generation, 165.0 MW that came out of retirement, 1,085.8 MW of net generation capacity

23 See "Analysis of the 2010/2011 RPM Auction Revised" (July 3, 2008) <http://www.monitoringanalytics.com/reports/Reports/2008/20102011-rpm-review-final-revised.pdf>.
24 See "Analysis of the 2010/2011 RPM Third Incremental Auction" (December 20, 2010) <http://www.monitoringanalytics.com/reports/Reports/2010/Analysis_of_2010_2011_RPM_Third_Incremental_Auction_20101220.pdf>.
25 See "Analysis of the 2011/2012 RPM Auction Revised" (October 1, 2008) <http://www.monitoringanalytics.com/reports/Reports/2008/20081002-review-of-2011-2012-rpm-auction-revised.pdf>.
26 See "Analysis of the 2011/2012 RPM First Incremental Auction" (January 6, 2011) <http://www.monitoringanalytics.com/reports/Reports/2011/Analysis_of_2011_2012_RPM_First_Incremental_Auction_20110106.pdf>.
27 See "Analysis of the 2012/2013 RPM Base Residual Auction" (August 6, 2009) <http://www.monitoringanalytics.com/reports/Reports/2009/Analysis_of_2012_2013_RPM_Base_Residual_Auction_20090806.pdf>.
28 See "Analysis of the 2013/2014 RPM Base Residual Auction Revised and Updated" (September 20, 2010) <http://www.monitoringanalytics.com/reports/Reports/2010/Analysis_of_2013_2014_RPM_Base_Residual_Auction_20090920.pdf>.
29 See "IMM Response to Maryland PSC re: Reliability Pricing Model and the 2013/2014 Delivery Year Base Residual Auction Results" (October 4, 2010) <http://www.monitoringanalytics.com/reports/Reports/2010/IMM_Response_to_MDPSC_RPM_and_2013-2014_BRA_Results.pdf>.
30 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).
31 Delivery years are from June 1 through May 31. The 2010/2011 delivery year runs from June 1, 2010, through May 31, 2011.

modifications (cap mods), and 43.7 MW of demand resource (DR) modifications (mods). The net EFORd effect was 11.3 MW. The EFORd effect is the measure of the net internal capacity change attributable to EFORd changes and not capacity modifications.

In the 2011/2012, 2012/2013, and 2013/2014 auctions, new generation increased 3,969.4 MW; 486.9 MW came out of retirement and net generation cap mods were -2,043.5 MW, for a total of 2,412.8 MW. DR and Energy Efficiency (EE) modifications totaled 11,360.5 MW through June 1, 2013. A decrease of 1,481.8 MW was due to higher EFORds. The classification of the Duquesne resources as external reduced total internal capacity by 3,006.6 MW, and the reclassification of the Duquesne resources as internal added 3,187.2 MW to total internal capacity. The integration of the ATSI zone resources added 13,175.2 MW to total internal capacity. The net effect from June 1, 2010, through June 1, 2013, was an increase in total internal capacity of 25,647.3 MW (16.1 percent) from 159,030.9 MW to 184,678.2 MW.

As shown in Table 5-2 and Table 5-11, in the 2010/2011 auction, the increase of 11 RPM generation resources consisted of 15 new resources (406.9 MW), four reactivated resources (161.7 MW), three that were previously entirely FRR committed (10.9 MW), one less resource excused from offering (3.9 MW), and one less resource entirely exported (39.9 MW), offset by four deactivated resources (59.6 MW), four resources exported from PJM (554.0 MW), three retired resources (348.4 MW), and two resources excused from offering (108.8 MW). The new resources consisted of seven CT resources (270.5 MW), five new wind resources (120.0 MW), three new diesel resources (16.4 MW), and four reactivated resources (165.0 MW). There were 23 demand resources (DR) offered compared to 38 DR resources offered in the 2009/2010 RPM auction.

As also shown in Table 5-2 and Table 5-11, in the 2011/2012 auction, the increase of 21 generation resources consisted of 20 new resources (2,203.7 MW), four reactivated resources (486.9 MW), three fewer excused resources (126.3 MW), and one additional resource imported (663.2 MW), offset by five additional resources committed fully to FRR (1.0 MW) and two retired resources (87.3 MW). The new resources consisted of 11 new CT resources (728.7 MW), four new wind resources (75.2 MW), two new steam resources (838.0 MW), one new combined cycle resource (556.5 MW), one new diesel resource (4.2 MW) and one new solar resource (1.1 MW). There were 37 demand resources (DR) offered compared to 23 DR resources offered in the 2010/2011 RPM auction.

As shown in Table 5-2 and Table 5-12, 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).[32] 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). There were 233 demand resources (DR) offered compared to 37 DR resources offered in the 2011/2012 RPM Base Residual

32 Disaggregation and aggregation of RPM resources reflect changes in how units are offered in RPM. For example, multiple units at a plant may be offered as a single unit or multiple units.

Auction. There were 53 Energy Efficiency (EE) resources offered as a new resource type for the 2012/2013 planning year.

As shown in Table 5-2 and Table 5-12, 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). There were 426 demand resources (DR) offered compared to 233 DR resources offered in the 2012/2013 RPM Base Residual Auction. There were 128 EE resources offered compared to 53 EE resources in the 2012/2013 RPM Base Residual Auction.

Table 5-3 shows generation capacity additions since the implementation of the Reliability Pricing Model. New generation capacity resources (5,986.1 MW), reactivated generation capacity resources (849.7 MW), uprates to existing generation capacity resources (4,905.3 MW), and the net increase in capacity imports (4,126.1 MW) totaled 15,867.2 MW since the implementation of the Reliability Pricing Model.

Table 5-2 Internal capacity: June 1, 2009 to June 1, 2013[33]

	UCAP (MW)					
	RTO	MAAC	EMAAC	DPL South	PSEG North	Pepco
Total internal capacity @ 01-Jun-09	157,318.2			1,587.0		
New generation	406.9			0.0		
Units out of retirement	165.0			0.0		
Generation cap mods	1,085.8			(85.5)		
DR mods	43.7			15.7		
Net EFORd effect	11.3			28.9		
Total internal capacity @ 01-Jun-10	159,030.9			1,546.1		
Classification of Duquesne resources to external	(3,006.6)					
New generation	2,203.7					
Units out of retirement	486.9					
Generation cap mods	439.0					
DR mods	684.4					
Net EFORd effect	44.4					
Total internal capacity @ 01-Jun-11	159,882.7	66,329.7	32,733.0	1,460.3	4,167.5	
Reclassification of Duquesne resources to internal	3,187.2	0.0	0.0	0.0	0.0	
New generation	661.3	61.9	59.7	0.0	0.0	
Units out of retirement	0.0	0.0	0.0	0.0	0.0	
Generation cap mods	(1,513.1)	(901.3)	(444.9)	(31.8)	(509.0)	
DR mods	8,028.7	3,829.7	1,480.9	64.6	67.6	
EE mods	652.5	186.9	24.4	0.0	0.9	
Net EFORd effect	(946.0)	(503.0)	(185.6)	5.8	18.3	
Total internal capacity @ 01-Jun-12	169,953.3	69,003.9	33,667.5	1,498.9	3,745.3	5,416.0
Correction in resource modeling	0.0	13.0	0.0			0.0
Adjusted internal capacity @ 01-Jun-12	169,953.3	69,016.9	33,667.5			5,416.0
Integration of existing ATSI resources	13,175.2	0.0	0.0			0.0
New generation	1,104.4	172.5	110.3			1.8
Units out of retirement	0.0	0.0	0.0			0.0
Generation cap mods	(969.4)	(1,007.7)	(884.9)			(11.0)
DR mods	1,894.1	900.2	689.5			61.8
EE mods	100.8	(34.9)	(0.3)			(20.7)
Net EFORd effect	(580.2)	31.9	118.5			(159.0)
Total internal capacity @ 01-Jun-13	184,678.2	69,078.9	33,700.6			5,288.9

33 The RTO includes MAAC, EMAAC and SWMAAC. MAAC includes EMAAC and SWMAAC. EMAAC includes DPL South and PSEG North. Results for only constrained LDAs are shown. Maps of the LDAs can be found in the *2010 State of the Market Report for PJM*, Appendix A, "PJM Geography."

Table 5-3 RPM generation capacity additions: 2007/2008 through 2013/2014

	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
Total	5,986.1	849.7	4,905.3	4,126.1	15,867.2

Demand

There was a 3,156.7 MW increase in the RPM reliability requirement from 153,480.1 MW on June 1, 2009, to 156,636.8 MW on June 1, 2010. This increase resulted from a higher peak-load forecast.

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, 2010, PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 77.7 percent (Table 5-4), down from 79.6 percent on June 1, 2009. The combined market share of LSEs not affiliated with any EDC and of non-PJM EDC affiliates was 22.3 percent, up from 20.4 percent on June 1, 2009. Prior to the 2009/2010 delivery year, obligation was defined as cleared and make-whole MW in the Base Residual Auction and the Second Incremental Auction plus ILR forecast obligations. Effective with the 2009/2010 through the 2011/2012 delivery year, obligation is defined as cleared and make-whole MW in the all RPM auctions for the delivery year plus ILR forecast obligations. Effective 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 5-4 PJM Capacity Market load obligation served: June 1, 2010

	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	66,223.4	12,774.7	24,974.3	1,144.4	12,755.6	567.1	15,408.6	133,848.1
Percent of total obligation	49.5%	9.5%	18.7%	0.9%	9.5%	0.4%	11.5%	100.0%

Market Concentration

Preliminary Market Structure Screen

Under the terms of the PJM Open Access Transmission Tariff (OATT), the MMU is required to apply the preliminary market structure screen (PMSS) prior to RPM Base Residual Auctions.[34] The results of the PMSS are applicable for the First, Second, Third, and Conditional Incremental Auctions for the given delivery year.[35] The purpose of the PMSS is to determine whether additional data are needed from owners of capacity resources in the defined areas in order to permit the MMU to apply the market structure tests defined in the Tariff.

An LDA or the RTO Region fails the PMSS if any one of the following three screens is failed: the market share of any capacity resource owner exceeds 20 percent; the HHI for all capacity resource owners is 1800 or higher; or there are not more than three jointly pivotal suppliers.[36]

As shown in Table 5-5, all defined markets failed the PMSS. As a result, capacity resource owners were required to submit avoidable cost rate (ACR) data or opportunity cost data to the MMU for resources for which they intended to submit non-zero sell offers unless certain other conditions were met.[37]

34 OATT Attachment M (PJM Market Monitoring Plan)-Appendix § II.D.1.
35 OATT Attachment DD § 5.11 (b).
36 OATT Attachment M-Appendix § II.D.2.
37 OATT Attachment DD § 6.7 (c).

Table 5-5 Preliminary market structure screen results: 2010/2011 through 2013/2014 RPM Auctions

RPM Markets	Highest Market Share	HHI	Pivotal Suppliers	Pass/Fail
2010/2011				
RTO	18.4%	853	1	Fail
EMAAC	31.3%	2053	1	Fail
SWMAAC	51.1%	4229	1	Fail
MAAC+APS	26.9%	1627	1	Fail
2011/2012				
RTO	18.0%	855	1	Fail
2012/2013				
RTO	17.4%	853	1	Fail
MAAC	17.6%	1071	1	Fail
EMAAC	32.8%	2057	1	Fail
SWMAAC	50.7%	4338	1	Fail
PSEG	84.3%	7188	1	Fail
PSEG North	90.9%	8287	1	Fail
DPL South	55.0%	3828	1	Fail
2013/2014				
RTO	14.4%	812	1	Fail
MAAC	18.1%	1101	1	Fail
EMAAC	33.0%	1992	1	Fail
SWMAAC	50.9%	4790	1	Fail
PSEG	89.7%	8069	1	Fail
PSEG North	89.5%	8056	1	Fail
DPL South	55.8%	3887	1	Fail
JCPL	28.5%	1731	1	Fail
Pepco	94.5%	8947	1	Fail

Auction Market Structure

As shown in Table 5-6, all participants in the total PJM market as well as the LDA RPM markets failed the TPS test in the 2010/2011 BRA, 2010/2011 Third Incremental Auction, the 2011/2012 BRA, the 2011/2012 First Incremental Auction, the 2011/2012 ATSI FRR Integration Auction, the 2012/2013 First Incremental Auction, the 2012/2013 ATSI FRR Integration Auction, and the 2013/2014 BRA.[38] The result was that offer caps were applied to all sell offers for resources which were subject to mitigation submitted by capacity market sellers that did not pass the test.[39,40,41] In the 2012/2013 BRA, all participants included in the incremental supply of EMAAC 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.[42] The relevant supply for the constrained LDA markets includes the incremental supply inside the constrained LDAs which was offered at a price higher than the unconstrained clearing price for the parent LDA market and less than or equal to 150 percent of the cost-based clearing price for the constrained LDA. The relevant demand consists of the MW needed inside the LDA to relieve the constraint.

Table 5-6 presents the results of the TPS test. A generation owner or owners are pivotal if the capacity of the owners' generation facilities is needed to meet the demand for capacity. The results of the TPS are measured by the Residual Supply Index (RSI_3). The RSI_x 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 RSI_x 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 RSI_x 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.

38 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 *Technical Reference for PJM Markets,* Section 8, "Three Pivotal Supplier Test" for additional discussion.

39 See OATT Attachment DD § 6.5.

40 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.

41 The definition of planned generation capacity resource and the rules regarding mitigation were redefined effective January 31, 2011. See 134 FERC ¶ 61,065 (2011).

42 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 5-6 RSI results: 2010/2011 through 2013/2014 RPM Auctions[43]

RPM Markets	RSI_3	Total Participants	Failed RSI_3 Participants
2010/2011 BRA			
RTO	0.60	68	68
DPL South	0.00	2	2
2010/2011 Third Incremental Auction			
RTO	0.53	47	47
2011/2012 BRA			
RTO	0.63	76	76
2011/2012 First Incremental Auction			
RTO	0.62	30	30
2011/2012 ATSI FRR Integration Auction			
RTO	0.07	21	21
2012/2013 BRA			
RTO	0.63	98	98
MAAC/SWMAAC	0.54	15	15
EMAAC/PSEG	7.03	6	0
PSEG North	0.00	2	2
DPL South	0.00	3	3
2012/2013 ATSI FRR Integration Auction			
RTO	0.10	16	16
2012/2013 First Incremental Auction			
RTO	0.60	25	25
EMAAC	0.00	2	2
2013/2014 BRA			
RTO	0.59	87	87
MAAC/SWMAAC	0.23	9	9
EMAAC/PSEG/PSEG North/DPL South	0.00	2	2
Pepco	0.00	1	1

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

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 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.[44]

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.[45,46] 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 to establish an EFORd; the net capability of each unit must be verified through winter and summer testing; a letter of non-recallability assuring 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.[47]

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 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.

44 See PJM Manual 18: PJM Capacity Market. See PJM. "Manual 18: PJM Capacity Market", Revision 10 (June 1, 2010).
45 See PJM. "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region", Schedule 9 & 10.
46 See PJM. "Manual 18: PJM Capacity Market", Revision 10 (June 1, 2010), pp. 22-23 & p.42.
47 See PJM. OATT, Schedule 1, Section 1.10.1A.

Planned External Generation Capacity Resource

Planned external generation capacity resources are eligible to be offered into an RPM auction if they meet specific requirements.[48,49] 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.[50] An external generation capacity resource becomes an existing external generation capacity resource as of the earlier of the date that interconnection service commences or the resource has cleared an RPM auction.[51]

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 market seller shows that the resource has a financially and physically firm commitment to an external sale of its capacity.[52] The capacity market seller must also identify the megawatt amount, export zone, and time period (in days) of the export.[53]

The MMU evaluates requests submitted by capacity market sellers to delist generation capacity resources, makes a determination as to whether the resource meets the applicable criteria to delist, and must inform both the capacity market seller and PJM of such determination.[54]

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 5-7, net exchange decreased 707.2 MW from June 1, 2009 to June 1, 2010. Net exchange, which is imports less exports, decreased due to an increase in exports of 952.5 MW offset by an increase in imports of 245.3 MW.

48 See PJM. "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region", Section 1.69A.
49 See PJM. "Manual 18: PJM Capacity Market", Revision 10 (June 1, 2010), pp. 25-26.
50 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).
51 The definition of planned generation capacity resource and the rules regarding mitigation were redefined effective January 31, 2011. See 134 FERC ¶ 61,065 (2011).
52 See OATT Attachment DD § 6.6.
53 *Id.*
54 OATT Attachment M-Appendix § II.C.2.

Table 5-7 PJM capacity summary (MW): June 1, 2007 to June 1, 2013[55]

	01-Jun-07	01-Jun-08	01-Jun-09	01-Jun-10	01-Jun-11	01-Jun-12	01-Jun-13
Installed capacity (ICAP)	163,721.1	164,444.1	166,916.0	168,061.5	172,666.6	181,159.7	197,775.0
Unforced capacity	154,076.7	155,590.2	157,628.7	158,634.2	163,144.3	171,147.8	186,588.0
Cleared capacity	129,409.2	129,597.6	132,231.8	132,190.4	132,221.5	136,143.5	152,743.3
Make-whole	0.0	0.0	0.0	0.0	43.0	222.1	14.0
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
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
RPM net excess	5,240.5	5,011.1	8,265.5	7,728.0	3,199.6	5,976.5	6,518.3
Imports	2,809.2	2,460.3	2,505.4	2,750.7	6,420.0	3,831.6	4,348.2
Exports	(3,938.5)	(3,838.1)	(2,194.9)	(3,147.4)	(3,158.4)	(2,637.1)	(2,438.4)
Net exchange	(1,129.3)	(1,377.8)	310.5	(396.7)	3,261.6	1,194.5	1,909.8
DR cleared	127.6	536.2	892.9	939.0	1,364.9	7,047.2	9,281.9
EE cleared						568.9	679.4
ILR	1,636.3	3,608.1	6,481.5	8,236.4	1,593.8		
FRR DR	445.6	452.8	423.6	452.9	452.9	488.1	488.6
Short-Term Resource Procurement Target						3,343.3	3,749.7

Demand-Side Resources

Under the PJM load management (LM) program, qualifying load management resources can be offered into RPM Auctions as capacity resources and receive the clearing price, or, prior to the 2012/2013 delivery year, they can be offered outside of the auction and receive the final, zonal ILR price.

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

- **Demand resources.** Capacity load resources that are offered into an RPM Auction as capacity and receive the relevant LDA or RTO resource clearing price.
- **Interruptible load for reliability (ILR).** Capacity load resources that are not offered into the RPM Auction, but are certified outside the auction process and receive the final, zonal ILR price determined after the close of the second incremental auction. ILR was effectively a free option to offer a resource at the BRA clearing price up until three months prior to the start of the delivery year.
- **Energy efficiency resources.** Capacity 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

55 Prior to the 2012/2013 delivery year, net excess under RPM was calculated as cleared capacity less the reliability requirement plus ILR. For 2007/2008 through 2010/2011, certified ILR was used in the calculation. Forecast ILR less FRR DR is used in the calculation when ILR was not certified and prior to 2011/2012 because PJM forecast ILR including FRR DR for the first four Base Residual Auctions. PJM forecast ILR excluding FRR DR for 2011/2012, so FRR DR is not subtracted in the calculation for 2011/2012. Net excess calculations for auctions prior to 2010/2011 were originally calculated as cleared capacity less the reliability requirement. For delivery years 2012/2013 and beyond, net excess under RPM is calculated as cleared capacity less the reliability requirement plus the Short-Term Resource Procurement Target.

consumption that is not reflected in the peak load forecast prepared for the delivery year, and that is fully implemented at all times during such delivery year, without any requirement of notice, dispatch, or operator intervention.[56] The Energy Efficiency (EE) resource type is eligible to be offered in RPM auctions starting with the 2012/2013 delivery year and also for incremental auctions in the 2011/2012 delivery year.[57]

Under RPM, DR and EE resources must be offered into the auction for the delivery year during which they will participate while ILR resources must be certified by a published deadline which is after the Base Residual Auction for the delivery year but no later than three months prior to the delivery year during which they will participate. Beginning with the 2012/2013 delivery year, the load management product ILR was eliminated. ILR was replaced by the Short-Term Resource Procurement Target, which reduces the RTO reliability requirement by 2.5 percent with the intent of permitting short lead time resource procurement in later auctions for the delivery year, was implemented with the 2012/2013 delivery year.

As shown in Table 5-8 and Table 5-10, capacity in the RPM load management programs increased by 1,783.3 MW from 6,899.7 MW on June 1, 2009 to 8,683.0 MW on June 1, 2010. Final ILR is certified three months before the delivery year and it may differ from the ILR forecast. Table 5-9 shows RPM commitments for DR and EE resources as the result of RPM auctions prior to adjustments for replacement transactions along with certified/forecast ILR.

56 See "Reliability Assurance Agreement among Load-Serving Entities in the PJM Region," Section M.
57 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).

Table 5-8 RPM load management statistics by LDA: June 1, 2009 to June 1, 2013[58,59]

	UCAP (MW)							
	RTO	MAAC+APS	MAAC	EMAAC	SWMAAC	DPL South	PSEG North	Pepco
DR cleared	892.9	813.9			356.3			
DR net replacements	(474.7)	(466.9)			(102.1)			
ILR certified	6,481.5	3,081.0			519.3			
RPM load management @ 01-June-2009	6,899.7	3,428.0			773.5			
DR cleared	962.9					14.9		
DR net replacements	(516.3)					(14.9)		
ILR certified	8,236.4					97.2		
RPM load management @ 01-June-2010	8,683.0					97.2		
DR cleared	1,364.9							
DR net replacements	(150.1)							
ILR forecast	1,593.8							
RPM load management @ 01-June-2011	2,808.6							
DR cleared	7,524.7		4,897.5	1,807.4		66.1	72.2	
EE cleared	568.9		179.9	20.0		0.0	0.9	
DR net replacements	0.0		0.0	0.0		0.0	0.0	
EE net replacements	0.0		0.0	0.0		0.0	0.0	
RPM load management @ 01-June-2012	8,093.6		5,077.4	1,827.4		66.1	73.1	
DR cleared	9,281.9		5,871.1	2,461.3				547.3
EE cleared	679.4		152.0	23.9				35.8
DR net replacements	0.0		0.0	0.0				0.0
EE net replacements	0.0		0.0	0.0				0.0
RPM load management @ 01-June-2013	9,961.3		6,023.1	2,485.2				583.1

58 For delivery years through 2010/2011, 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.

59 For 2010/2011, DPL zonal ILR MW are allocated to the DPL South LDA using the sub-zonal load ratio share (57.72 percent for DPL South).

Table 5-9 RPM load management cleared capacity and ILR: 2007/2008 through 2013/2014[60,61]

	DR Cleared		EE Cleared		ILR	
Delivery Year	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)
2007/2008	123.5	127.6	0.0	0.0	1,584.6	1,636.3
2008/2009	540.9	559.4	0.0	0.0	3,488.5	3,608.1
2009/2010	864.5	892.9	0.0	0.0	6,273.8	6,481.5
2010/2011	930.9	962.9	0.0	0.0	7,961.3	8,236.4
2011/2012	1,319.5	1,364.9	0.0	0.0	1,540.6	1,593.8
2012/2013	7,286.5	7,524.7	551.3	568.9	0.0	0.0
2013/2014	8,977.8	9,281.9	658.5	679.4	0.0	0.0

Table 5-10 RPM load management statistics: June 1, 2007 to June 1, 2013[62,63]

	DR and EE Cleared Plus ILR		DR Net Replacements		EE Net Replacements		Total RPM LM	
	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)
01-Jun-07	1,708.1	1,763.9	0.0	0.0	0.0	0.0	1,708.1	1,763.9
01-Jun-08	4,029.4	4,167.5	(38.7)	(40.0)	0.0	0.0	3,990.7	4,127.5
01-Jun-09	7,138.3	7,374.4	(459.5)	(474.7)	0.0	0.0	6,678.8	6,899.7
01-Jun-10	8,892.2	9,199.3	(499.1)	(516.3)	0.0	0.0	8,393.1	8,683.0
01-Jun-11	2,860.1	2,958.7	(145.1)	(150.1)	0.0	0.0	2,715.0	2,808.6
01-Jun-12	7,837.8	8,093.6	0.0	0.0	0.0	0.0	7,837.8	8,093.6
01-Jun-13	9,636.3	9,961.3	0.0	0.0	0.0	0.0	9,636.3	9,961.3

Market Conduct

Offer Caps

If a capacity resource owner failed the market power test for the auction and the submitted sell offer exceeded the defined offer cap, market power mitigation measures were applied such that the sell offer was set equal to the defined offer cap.

The opportunity cost option allows resource owners to input a documented export opportunity cost as the offer for the unit, subject to export limits. If the relevant RPM market clears above the opportunity cost, the unit's capacity is sold in the RPM market. If the opportunity cost is greater than the clearing price, the unit's capacity does not clear in the RPM market and it is available for export.

60 For delivery years through 2010/2011, certified ILR data is shown, because the certified ILR data are now available. Effective the 2012/2013 delivery year, ILR was eliminated. Starting with the 2012/2013 delivery year and also for incremental auctions in the 2011/2012 delivery year, the Energy Efficiency (EE) resource type is eligible to be offered in RPM auctions.

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

62 For delivery years through 2010/2011, certified ILR data were used in the calculation, because the certified ILR data are now available. Effective the 2012/2013 delivery year, ILR was eliminated. Starting with the 2012/2013 delivery year and also for incremental auctions in the 2011/2012 delivery year, the Energy Efficiency (EE) resource type is eligible to be offered in RPM auctions.

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

Avoidable costs are the costs that a generation owner would not incur if the generating unit did not operate for the delivery year.[64] 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 also include annual capital recovery associated with investments required to maintain a unit as a capacity resource. This component of avoidable costs is termed the avoidable project investment recovery rate (APIR). Avoidable cost based offer caps are defined to be the avoidable cost rate (ACR) less net revenues from all other PJM markets and from 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.

Table 5-11 ACR statistics: 2010/2011 through 2011/2012 RPM Auctions

	2010/2011 BRA		2010/2011 Third Incremental Auction		2011/2012 BRA		2011/2012 First Incremental Auction		2011/2012 ATSI Integration Auction	
Calculation Type	Number of Resources	Percent of Generation Resources Offered	Number of Resources	Percent of Generation Resources Offered	Number of Resources	Percent of Generation Resources Offered	Number of Resources	Percent of Generation Resources Offered	Number of Resources	Percent of Generation Resources Offered
Default ACR selected	370	33.5%	7	2.3%	299	26.6%	44	34.1%	57	40.4%
ACR data input (APIR)	134	12.1%	1	0.3%	133	11.8%	18	14.0%	4	2.8%
ACR data input (non-APIR)	20	1.8%	0	0.0%	12	1.1%	1	0.8%	0	0.0%
Opportunity cost input	8	0.7%	1	0.3%	24	2.1%	2	1.6%	3	2.1%
Default ACR and opportunity cost input	0	0.0%	0	0.0%	2	0.2%	3	2.3%	0	0.0%
Generation resources with offer caps	532	48.1%	9	2.9%	470	41.8%	68	52.8%	64	45.3%
Uncapped planned generation resources	15	1.4%	0	0.0%	20	1.8%	1	0.8%	5	3.5%
Generators with 1.1 times BRA clearing price offer cap	NA	NA	193	63.7%	NA	NA	NA	NA	52	36.9%
Generation price takers	557	50.5%	101	33.4%	635	56.4%	60	46.4%	20	14.3%
Generation resources offered	1,104	100.0%	303	100.0%	1,125	100.0%	129	100.0%	141	100.0%
Demand resources offered	23		34		37		0		46	
Energy efficiency resources offered	0		0		0		0		1	
Total capacity resources offered	1,127		337		1,162		129		188	

64 See OATT Attachment DD § 6.8 (b).

Table 5-12 ACR statistics: 2012/2013 through 2013/2014 RPM Auctions

	2012/2013 BRA		2012/2013 ATSI Integration Auction		2012/2013 First Incremental Auction		2013/2014 BRA	
Calculation Type	Number of Resources	Percent of Generation Resources Offered	Number of Resources	Percent of Generation Resources Offered	Number of Resources	Percent of Generation Resources Offered	Number of Resources	Percent of Generation Resources Offered
Default ACR selected	465	41.0%	117	67.6%	92	56.8%	580	49.6%
ACR data input (APIR)	118	10.4%	12	6.9%	14	8.6%	92	7.9%
ACR data input (non-APIR)	2	0.2%	0	0.0%	0	0.0%	15	1.3%
Opportunity cost input	8	0.7%	2	1.2%	2	1.2%	6	0.5%
Default ACR and opportunity cost input	14	1.2%	0	0.0%	0	0.0%	7	0.6%
Generation resources with offer caps	607	53.5%	131	75.7%	108	66.6%	700	59.9%
Uncapped planned generation resources	11	1.0%	0	0.0%	17	10.5%	20	1.7%
Generators with 1.1 times BRA clearing price offer cap	NA	NA	26	15.0%	NA	NA	NA	NA
Generation price takers	515	45.5%	16	9.3%	37	22.9%	450	38.4%
Generation resources offered	1,133	100.0%	173	100.0%	162	100.0%	1,170	100.0%
Demand resources offered	233		46		77		426	
Energy efficiency resources offered	53		2		3		128	
Total capacity resources offered	1,419		221		242		1,724	

Table 5-13 APIR statistics: 2010/2011 through 2013/2014 RPM Auctions[65,66,67,68]

		Weighted-Average ($ per MW-day UCAP)					
		Combined Cycle	Combustion Turbine	Oil or Gas Steam	Subcritical/ Supercritical Coal	Other	Total
2010/2011 BRA							
Non-APIR units	ACR	$34.39	$27.10	$67.57	$167.08	$82.55	$80.86
	Net revenues	$96.75	$18.81	$15.19	$302.79	$391.00	$151.31
	Offer caps	$10.13	$14.12	$52.38	$9.67	$4.53	$11.94
APIR units	ACR	$61.61	$49.26	$152.09	$654.18	$34.62	$360.27
	Net revenues	$26.84	$10.32	$20.94	$525.48	$2.07	$263.27
	Offer caps	$37.30	$39.41	$131.15	$155.39	$32.55	$110.25
	APIR	$9.87	$30.93	$60.54	$521.16	$22.42	$272.18
	Maximum APIR effect						$577.03
2011/2012 BRA							
Non-APIR units	ACR	$39.52	$30.17	$72.20	$181.52	$62.54	$75.61
	Net revenues	$69.04	$20.16	$17.27	$466.41	$322.78	$169.93
	Offer caps	$11.76	$16.42	$62.13	$7.88	$11.50	$17.64
APIR units	ACR	$61.66	$56.28	$184.34	$723.65	$36.03	$424.49
	Net revenues	$78.17	$10.35	$19.81	$531.93	$2.06	$286.80
	Offer caps	$34.69	$46.18	$164.54	$203.41	$33.97	$147.77
	APIR	$11.82	$37.28	$91.30	$578.47	$24.68	$324.58
	Maximum APIR effect						$523.26
2011/2012 First IA							
Non-APIR units	ACR	$54.15	$29.43	NA	$284.63	$30.04	$169.77
	Net revenues	$220.31	$44.98	NA	$298.96	$0.07	$195.83
	Offer caps	$2.66	$2.64	NA	$150.63	$29.97	$83.01
APIR units	ACR	$220.20	$152.28	$194.25	$583.59	NA	$326.57
	Net revenues	$81.72	$6.94	$23.64	$328.71	NA	$128.90
	Offer caps	$138.48	$145.34	$170.62	$254.88	NA	$197.67
	APIR	$220.19	$120.84	$82.87	$324.31	NA	$170.61
	Maximum APIR effect						$468.26
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

65 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.

66 This table has been updated since the MMU RPM Auction reports were posted. The 2010/2011 and 2011/2012 BRA values for Oil and Gas Steam and Sub Critical/Super Critical Coal for resources with an APIR component were updated due to a prior misclassification.

67 For reasons of confidentiality, the APIR statistics do not include opportunity cost based offer cap data.

68 Statistics for the 2010/2011 Third IA are not included as the majority of the resources elected the offer cap option of 1.1 times the BRA clearing price.

Table 5-13 APIR statistics: 2010/2011 through 2013/2014 RPM Auctions (continued)

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

2010/2011 RPM Base Residual Auction

As shown in Table 5-11, 1,104 generation resources submitted offers in the 2010/2011 RPM Base Residual Auction as compared to 1,093 generation resources offered in the 2009/2010 RPM Auction. Unit-specific offer caps were calculated for 154 resources (13.9 percent of all generation resources offered) including 134 resources (12.1 percent) with an APIR component and 20 resources (1.8 percent) without an APIR component. The MMU calculated offer caps for 532 resources (48.1 percent), of which 370 (33.5 percent) were based on the technology specific default (proxy) ACR values. Of the 557 generation resources, 15 planned generation resources had uncapped offers (1.4 percent), while the remaining 557 generation resources were price takers (50.5 percent), of which the offers for 546 resources were zero and the offers for 11 resources were set to zero because no data were submitted.[69]

Of the 1,104 generation resources which submitted offers, 134 (12.1 percent) included an APIR component (Table 5-11). As shown in Table 5-13, the weighted-average gross ACR for resources with APIR ($360.27 per MW-day) and the weighted-average offer caps, net of net revenues, for resources with APIR ($110.25 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 $272.18 per MW-day to the ACR value of the APIR resources.[70] The default

69 Planned units are subject to mitigation under specific circumstances defined in the tariff. Some of the uncapped planned units submitted zero price offers.

70 The 134 units which had an APIR component submitted $1.5 billion for capital projects associated with 12,645.3 MW UCAP.

ACR values included an average APIR of $0.91 per MW-day. The highest APIR for a technology ($521.16 per MW-day) was for subcritical/supercritical coal resources. The maximum APIR effect ($577.03 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

2010/2011 RPM Third Incremental Auction

As shown in Table 5-11, 303 generation resources submitted offers in the 2010/2011 RPM Third Incremental Auction. Unit specific offer caps were calculated for one resource (0.3 percent of all generation resources offered). The MMU calculated offer caps for nine resources (2.9 percent), of which seven were based on the technology specific default (proxy) ACR values. Of the 303 generation resources, 193 resources elected the offer cap option of 1.1 times the BRA clearing price (63.7 percent), while the remaining 101 resources were price takers (33.4 percent).

2011/2012 RPM Base Residual Auction

As shown in Table 5-11, 1,125 generation resources submitted offers in the 2011/2012 RPM Base Residual Auction as compared to 1,104 generation resources offered in the 2010/2011 RPM Base Residual Auction. Unit-specific offer caps were calculated for 145 resources (12.9 percent of all generation resources offered) including 133 resources (11.8 percent) with an APIR component and 12 resources (1.1 percent) without an APIR component. The MMU calculated offer caps for 470 resources (41.8 percent), of which 301 (26.8 percent) were based on the technology specific default (proxy) ACR values. Of the 1,125 generation resources, 20 planned generation resources had uncapped offers (1.8 percent), while the remaining 635 generation resources were price takers (56.4 percent), of which the offers for 578 resources were zero and the offers for 55 resources were set to zero because no data were submitted.[71]

Of the 1,125 generation resources which submitted offers, 133 (11.8 percent) included an APIR component (Table 5-11). As shown in Table 5-13, the weighted-average gross ACR for resources with APIR ($424.49 per MW-day) and the weighted-average offer caps, net of net revenues, for resources with APIR ($147.77 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 $324.58 per MW-day to the ACR value of the APIR resources.[72] The default ACR values included an average APIR of $0.91 per MW-day. The highest APIR for a technology ($578.47 per MW-day) was for subcritical/supercritical coal resources. The maximum APIR effect ($523.26 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

2011/2012 RPM First Incremental Auction

As shown in Table 5-11, 129 generation resources submitted offers in the 2011/2012 RPM First Incremental Auction. Unit-specific offer caps were calculated for 19 resources (14.7 percent of all generation resources offered) including 18 resources (14.0 percent) with an APIR component and one resource (0.8 percent) without an APIR component. The MMU calculated offer caps for 68 resources (52.8 percent), of which 47 (36.4 percent) were based on the technology specific default

71 Planned units are subject to mitigation under specific circumstances defined in the tariff. Some of the 20 uncapped planned units submitted zero price offers.

72 The 133 units which had an APIR component submitted $613.8 million for capital projects associated with 8,813.7 MW UCAP.

(proxy) ACR values. Of the 129 generation resources, one planned generation resource had an uncapped offer (0.8 percent) while the remaining 60 generation resources were price takers (46.4 percent), of which the offers for 36 resources were zero and the offers for 24 resources were set to zero because no data were submitted.

Of the 129 generation resources which submitted offers, 18 resources (14.0 percent) included an APIR component (Table 5-11). As shown in Table 5-13, the weighted-average gross ACR for resources with APIR ($326.57 per MW-day) and the weighted-average offer caps, net of net revenues, for resources with APIR ($197.67 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 $170.61per 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 ($324.31 per MW-day) was for subcritical/supercritical coal units. The maximum APIR effect ($468.26 per MW-day) was the maximum amount by which an offer cap was increased by APIR.

2011/2012 ATSI Integration Auction

As shown in Table 5-11, 141 generation resources submitted offers in the 2011/2012 ATSI Integration Auction. Unit-specific offer caps were calculated for four resources (2.8 percent of all generation resources), all of which included an APIR component. The MMU calculated offer caps for 64 resources (45.3 percent), of which 57 were based on the technology specific default (proxy) ACR values. Of the 141 generation resources, 52 resources elected offer cap option of 1.1 times the BRA clearing price (36.9 percent), 5 planned generation resources had uncapped offers (3.5 percent), while the remaining 20 resources were price takers (14.3 percent), of which the offers for 18 resources were zero and the offers for two resources were set to zero because no data were submitted.

2012/2013 RPM Base Residual Auction

As shown in Table 5-12, 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 resources (10.6 percent of all generation resources offered) including 118 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 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 resources were zero and the offers for three resources were set to zero because no data were submitted.[73]

Of the 1,133 generation resources which submitted offers, 118 (10.4 percent) included an APIR component (Table 5-12). As shown in Table 5-13, 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

73 Planned units are subject to mitigation under specific circumstances defined in the tariff. Some of the 11 uncapped planned units submitted zero price offers.

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.[74] 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 5-12, 173 generation resources submitted offers in the 2012/2013 ATSI Integration Auction. Unit-specific offer caps were calculated for 12 resources (6.9 percent of all generation resources), all of which included an APIR component. The MMU calculated offer caps for 131 resources (75.7 percent), of which 117 were based on the technology specific default (proxy) ACR values. Of the 173 generation resources, 26 resources elected offer cap option of 1.1 times the BRA clearing price (15.0 percent), while the remaining 16 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 5-12, 162 generation resources submitted offers in the 2012/2013 RPM First Incremental Auction. Unit-specific offer caps were calculated for 14 resources (8.6 percent of all generation resources), all of which included an APIR component. The MMU calculated offer caps for 108 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 resources were price takers (22.9 percent), of which the offers for 24 resources were zero and the offers for 13 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 (Table 5-12). As shown in Table 5-13, 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.

2013/2014 RPM Base Residual Auction

As shown in Table 5-12, 1,170 generation resources submitted offers compared to 1,133 generation resources offered in the 2012/2013 RPM Base Residual Auction. Unit-specific offer

74 The 118 units which had an APIR component submitted $567.2 million for capital projects associated with 11,124.8 MW of UCAP.

caps were calculated for 107 resources (9.1 percent of all generation resources offered) including 92 resources (7.9 percent) with an Avoidable Project Investment Recovery Rate (APIR) component and 15 resources (1.3 percent) without an APIR component. The MMU calculated offer caps for 700 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 resources were zero and the offers for nine resources were set to zero because no data were submitted.[75]

Of the 1,170 generation resources which submitted offers, 92 (7.9 percent) included an APIR component (Table 5-12). As shown in Table 5-13, 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.[76] 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.

Market Performance

The RTO resource clearing price increased $72.25 per MW-day (70.8 percent) from $102.04 per MW-day for the 2009/2010 BRA to $174.29 per MW-day for the 2010/2011 BRA (Table 5-14).

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 $100.26 per MW-day in 2013. Figure 5-1 presents cleared MW weighted average capacity market prices on a calendar year basis for the entire history of the PJM capacity markets.

As Table 5-7 shows, RPM net excess decreased 537.5 MW from 8,265.5 MW on June 1, 2009, to 7,728.0 MW on June 1, 2010, because of a 2,251.0 MW increase in the reliability requirement and a 41.4 MW decrease in cleared capacity, offset by a 1,754.9 MW increase in ILR.[77] The increase in unforced capacity of 1,005.5 MW was the result of an increase in total internal capacity of 1,712.7 MW plus an increase in imports of 245.3 MW, offset by an increase in exports of 952.5 MW[78] (Table 5-2).

75 Planned units are subject to mitigation under specific conditions defined in the tariff. Some of the 20 uncapped planned units submitted zero price offers.

76 The 92 units which had an APIR component submitted $326.7 million for capital projects associated with 10,328.3 MW of UCAP.

77 Prior to the 2012/2013 delivery year, net excess under RPM was calculated as cleared capacity less the reliability requirement plus ILR. For 2007/2008 through 2010/2011, certified ILR was used in the calculation. Forecast ILR less FRR DR is used in the calculation when ILR was not certified and prior to 2011/2012 because PJM forecast ILR including FRR DR for the first four Base Residual Auctions. PJM forecast ILR excluding FRR DR for 2011/2012, so FRR DR is not subtracted in the calculation for 2011/2012. Net excess calculations for auctions prior to 2010/2011 were originally calculated as cleared capacity less the reliability requirement. For delivery years 2012/2013 and beyond, net excess under RPM is calculated as cleared capacity less the reliability requirement plus the Short-Term Resource Procurement Target.

78 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 5-15 shows RPM revenue by resource type for all RPM auctions held to date with over $500 million for new/reactivated resources based on the unforced MW cleared and the resource clearing prices.

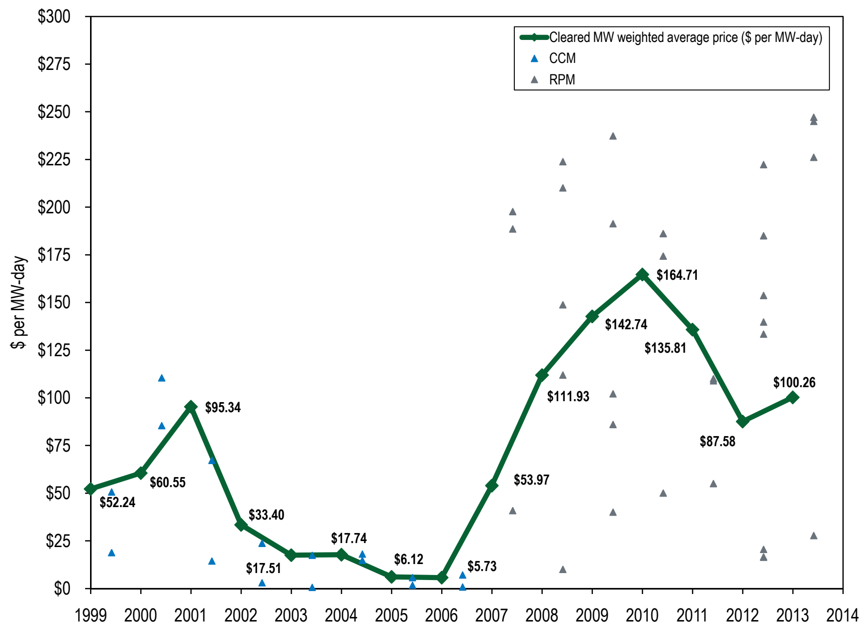
Table 5-14 Capacity prices: 2007/2008 through 2013/2014 RPM Auctions

	RPM Clearing Price ($ per MW-day)							
	RTO	MAAC	APS	EMAAC	SWMAAC	DPL South	PSEG North	Pepco
2007/2008 BRA	$40.80	$40.80	$40.80	$197.67	$188.54	$197.67	$197.67	$188.54
2008/2009 BRA	$111.92	$111.92	$111.92	$148.80	$210.11	$148.80	$148.80	$210.11
2008/2009 Third IA	$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 IA	$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 IA	$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 IA	$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
2012/2013 BRA	$16.46	$133.37	$16.46	$139.73	$133.37	$222.30	$185.00	$133.37
2012/2013 ATSI FRR Integration Auction	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46
2012/2013 First IA	$16.46	$16.46	$16.46	$153.67	$16.46	$153.67	$153.67	$16.46
2013/2014 BRA	$27.73	$226.15	$27.73	$245.00	$226.15	$245.00	$245.00	$247.14

Table 5-15 RPM revenue by type: 2007/2008 through 2013/2014[79,80]

Type	2007/2008	2008/2009	2009/2010	2010/2011	2011/2012	2012/2013	2013/2014	Total
Demand Resources	$5,537,085	$35,349,116	$65,762,003	$60,235,796	$54,950,874	$262,109,171	$540,278,140	$1,024,222,184
Energy Efficiency Resources	$0	$0	$0	$0	$0	$11,155,913	$18,323,569	$29,479,482
Imports	$22,225,980	$60,918,903	$56,517,793	$106,046,871	$185,361,066	$13,115,246	$31,191,272	$475,377,131
Coal existing	$1,022,993,505	$1,845,819,870	$2,420,481,808	$2,662,434,386	$1,595,479,644	$1,015,782,743	$1,720,750,315	$12,283,742,271
Coal new/reactivated	$0	$0	$1,854,781	$3,168,069	$28,326,936	$7,413,749	$12,493,918	$53,257,453
Gas existing	$1,476,347,853	$1,970,649,854	$2,379,139,654	$2,684,798,328	$1,658,450,310	$1,148,404,128	$1,944,548,260	$13,262,338,388
Gas new/reactivated	$3,472,667	$9,751,112	$30,168,831	$58,065,964	$98,115,633	$75,945,518	$165,431,441	$440,951,166
Hydroelectric existing	$209,490,444	$287,850,403	$364,742,517	$442,429,815	$278,438,160	$178,866,339	$308,348,743	$2,070,166,420
Hydroelectric new/reactivated	$0	$0	$0	$0	$0	$0	$0	$0
Nuclear existing	$996,085,233	$1,322,601,837	$1,517,723,628	$1,799,258,125	$1,079,384,691	$761,838,276	$1,341,583,669	$8,818,475,460
Nuclear new/reactivated	$0	$0	$0	$0	$0	$0	$0	$0
Oil existing	$485,747,786	$511,428,579	$610,535,427	$570,678,904	$316,085,286	$353,422,286	$559,796,082	$3,407,694,349
Oil new/reactivated	$0	$4,837,523	$5,676,582	$4,339,539	$930,006	$2,772,987	$5,669,955	$24,226,592
Solid waste existing	$29,956,764	$33,843,188	$41,243,412	$40,731,606	$25,605,360	$26,835,364	$43,611,119	$241,826,814
Solid waste new/reactivated	$0	$0	$523,739	$413,503	$261,690	$469,425	$2,411,690	$4,080,046
Solar existing	$0	$0	$0	$0	$0	$0	$0	$0
Solar new/reactivated	$0	$0	$0	$0	$44,286	$944,720	$947,905	$1,936,911
Wind existing	$430,065	$1,180,153	$2,011,156	$1,819,413	$1,072,929	$779,404	$1,321,010	$8,614,130
Wind new/reactivated	$0	$2,917,048	$6,836,827	$15,232,177	$9,730,842	$3,771,957	$11,859,958	$50,348,808
Total	$4,252,287,381	$6,087,147,586	$7,503,218,157	$8,449,652,496	$5,332,237,713	$3,863,627,224	$6,708,567,045	$42,196,737,603

Figure 5-1 History of capacity prices: Calendar year 1999 through 2013[81,82]



79 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.

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

81 1999-2006 capacity prices are CCM combined market, weighted average prices. The 2007 capacity price is a combined CCM/RPM weighted average price. The 2008-2013 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.

82 The RPM weighted average prices were updated since the *2010 Quarterly State of the Market Report for PJM: January through September* to account for Make-Whole MW.

Table 5-16 RPM cost to load: 2010/2011 through 2013/2014 RPM Auctions[83,84,85]

	Net Load Price ($ per MW-day)	UCAP Obligation (MW)	Annual Charges
2010/2011 BRA			
RTO	$182.85	129,332.6	$8,631,690,057
DPL	$187.04	4,515.5	$308,271,379
2011/2012 BRA			
RTO	$110.04	133,815.3	$5,389,363,034
2012/2013 BRA			
RTO	$16.46	69,648.3	$418,440,022
MAAC	$129.63	31,338.7	$1,482,789,024
EMAAC	$135.18	21,171.5	$1,044,616,630
DPL	$162.99	4,685.6	$278,752,670
PSEG	$149.65	12,642.7	$690,572,720
2013/2014 BRA			
RTO	$27.73	85,918.0	$869,614,741
MAAC	$223.85	23,944.0	$1,956,350,506
EMAAC	$240.41	38,634.3	$3,390,146,303
Pepco	$236.93	7,996.7	$691,550,218

Table 5-16 shows the RPM annual charges to load. For the 2010/2011 planning year, annual charges totaled approximately $8.9 billion.

2010/2011 RPM Base Residual Auction

Cleared capacity resources across the entire RTO will receive a total of $8.4 billion based on the unforced MW cleared and the prices in the 2010/2011 BRA.

RTO

Table 5-17 shows total RTO offer data for the 2010/2011 RPM Base Residual Auction, including the DPL South LDA. Total internal RTO unforced capacity of 159,030.9 MW includes all generation resources and DR that qualified as a PJM capacity resource for the 2010/2011 RPM Base Residual Auction, excluding external units, and also includes owners' modifications to installed capacity

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

84 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.

85 Prior to the 2009/2010 delivery year, the Final UCAP Obligation is determined after the clearing of the Second IA. For the 2009/2010 through 2011/2012 delivery years, the Final UCAP Obligations are determined after the clearing of the Third IA. 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 2011/2012, 2012/2013, and 2013/2014 Net Load Prices and Obligation MW are not finalized.

ratings which are permitted under the PJM Reliability Assurance Agreement (RAA) and associated manuals.[86,87]

After accounting for FRR committed resources and for imports, RPM capacity was 137,360.7 MW.[88] This amount was reduced by exports of 3,147.4 MW and 490.1 MW which were excused from the RPM must-offer requirement as a result of planned capacity retirements (275.9 MW), non-utility generator (NUG) ownership questions (166.2 MW), planned reductions due to environmental regulations (33.0 MW), and other factors (15.0 MW). Subtracting 630.5 MW of FRR optional volumes not offered, resulted in 133,092.7 MW that were available to be offered into the auction.[89] After accounting for the above, all capacity resources were offered into the RPM Auction. There were seven new CT units (270.5 MW), three new diesel resources (16.4 MW), and five new wind resources (120.0 MW) offered into the auction. Offered volumes included 1,034.9 MW of EFORd offer segments.[90]

The downward sloping demand curve resulted in more capacity cleared in the market than would have cleared with a vertical demand curve equal to the reliability requirement. The 132,190.4 MW of cleared resources for the entire RTO represented a reserve margin of 16.5 percent, resulted in net excess of 1,149.2 MW greater than the reliability requirement of 132,698.8 MW (IRM of 15.5 percent).[91,92,93] As shown in Figure 5-2, the downward sloping demand curve resulted in a resource clearing price of $174.29 per MW-day. Net excess decreased 537.5 MW from the net excess of 8,265.5 MW in the 2009/2010 RPM Base Residual Auction, because of a 2,251.0 MW increase in the reliability requirement and a 41.4 MW decrease in cleared capacity, offset by a 1,754.9 MW increase in ILR (Table 5-7). Certified ILR was 8,236.4 MW.

As shown in Table 5-17, the net load price that LSEs will pay is $182.85 per MW-day in the RTO area not included in the constrained LDAs. This value is the final zonal capacity price. Prior to the 2012/2013 delivery year, the final zonal capacity price is the resource-clearing price adjusted for differences between the certified ILR for the delivery year and the forecasted RTO ILR obligation.

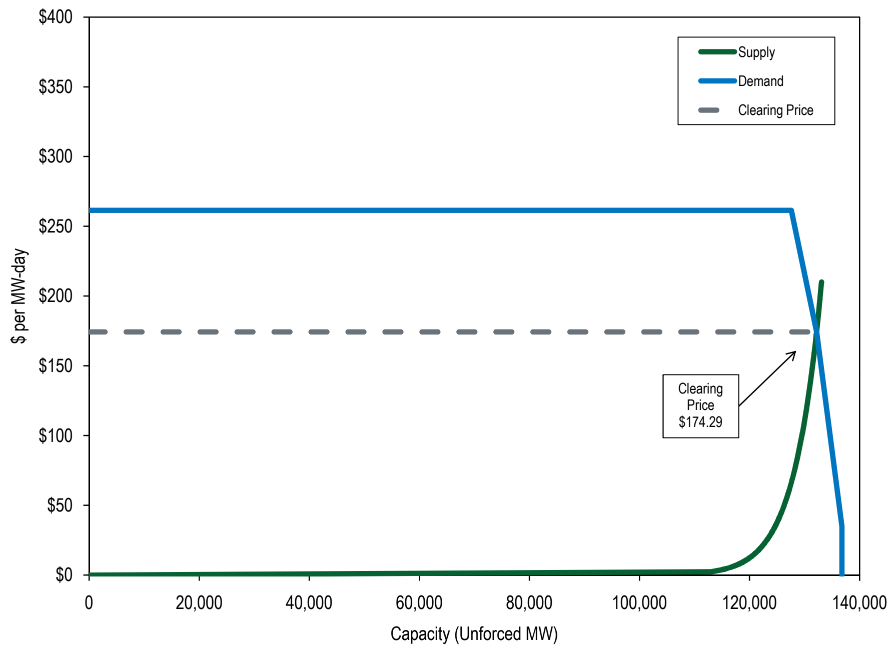
86 See "Reliability Assurance Agreement among Load-Serving Entities in the PJM Region" (June 1, 2007), Schedule 9.
87 See PJM. "Manual 21: Rules and Procedures for Determination of Generating Capability," Revision 09 (May 1, 2010).
88 The FRR alternative allows an LSE, subject to certain conditions, to avoid direct participation in the RPM Auctions. The LSE is required to submit an FRR capacity plan to satisfy the unforced capacity obligation for all load in its service area.
89 FRR entities are allowed to offer into the RPM Auction excess volumes above their FRR quantities, subject to a sales cap amount. The 630.5 MW are a combination of excess volumes included in the sales cap amount which were not offered into the auction and volumes above the sales cap amount which were not permitted to be offered into the auction.
90 The EFORd offer segment was eliminated on March 27, 2009. See 126 FERC ¶ 61,275 (2009) at P 170.
91 Prior to the 2012/2013 delivery year, net excess under RPM was calculated as cleared capacity less the reliability requirement plus ILR. For delivery years 2012/2013 and beyond, net excess under RPM is calculated as cleared capacity less the reliability requirement plus the Short-Term Resource Procurement Target.
92 The IRM increased from 15.0 percent to 15.5 percent for the 2010/2011 delivery year.
93 The demand curve UCAP quantities are based on three points, which are ratios of the installed reserve margin (IRM = 15.5 percent) times the reliability requirement, less the forecast RTO ILR obligation. For the three points, the ratios are 1.12/1.15, 1.16/1.15 and 1.20/1.15. For these three points the UCAP prices are based on factors multiplied by net Cost of New Entry (CONE) divided by one minus the pool-wide EFORd. Net CONE is defined as CONE minus the energy and ancillary service revenue offset (E&AS). For the three points, the factors are 1.5, 1.0 and 0.2. For 2010/2011, CONE was $197.83 per MW-day and E&AS was $34.36 MW-day.

Table 5-17 RTO offer statistics: 2010/2011 RPM Base Residual Auction[94]

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Total internal RTO capacity (gen and DR)	168,457.3	159,030.9		
FRR	(26,305.7)	(24,420.9)		
Imports	2,982.4	2,750.7		
RPM capacity	145,134.0	137,360.7		
Exports	(3,378.2)	(3,147.4)		
FRR optional	(744.5)	(630.5)		
Excused	(546.2)	(490.1)		
Available	140,465.1	133,092.7	100.0%	100.0%
Generation offered	139,529.5	132,124.8	99.3%	99.3%
DR offered	935.6	967.9	0.7%	0.7%
Total offered	140,465.1	133,092.7	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO	139,253.9	132,190.4	99.1%	99.3%
Cleared in LDAs	0.0	0.0	0.0%	0.0%
Total cleared	139,253.9	132,190.4	99.1%	99.3%
Make-whole	0.0	0.0	0.0%	0.0%
Uncleared in RTO	1,184.5	875.9	0.9%	0.7%
Uncleared in LDAs	26.7	26.4	0.0%	0.0%
Total uncleared	1,211.2	902.3	0.9%	0.7%
Reliability requirement		132,698.8		
Total cleared plus make-whole		132,190.4		
ILR certified		8,236.4		
Net excess/(deficit)		7,728.0		
Resource clearing price ($ per MW-day)		$174.29	A	
Final zonal capacity price ($ per MW-day)		$182.85	B	
Final zonal CTR credit rate ($ per MW-day)		$0.00	C	
Final zonal ILR price ($ per MW-day)		$174.29	A-C	
Net load price ($ per MW-day)		$182.85	B-C	

94 Prices are only for those capacity resources outside of DPL South.

Figure 5-2 RTO market supply/demand curves: 2010/2011 RPM Base Residual Auction[95]



DPL South

Table 5-18 shows total DPL South offer data for the 2010/2011 RPM Base Residual Auction. Total internal DPL South unforced capacity of 1,546.1 MW includes all generation resources and DR that qualified as a PJM capacity resource, excluding external units, and also includes owners' modifications to ICAP ratings. All imports offered into the auction are modeled in the RTO, so total DPL South RPM unforced capacity was 1,546.1 MW.[96] All DPL South capacity resources were offered into the RPM Auction.

All of the 1,519.7 MW cleared in DPL South were cleared in the RTO before DPL South became constrained. Of the 26.4 MW of incremental supply, none cleared, because all 26.4 MW were priced above the demand curve. The DPL South resource clearing price was $186.12 per MW-day, as shown in Figure 5-3. The price was determined by the intersection of the demand curve and a vertical section of the supply curve.

Total resources in DPL South were 2,966.7 MW, which when combined with certified ILR of 97.2 MW resulted in a net excess of 14.5 MW (0.5 percent) greater than the reliability requirement of 3,049.4 MW.

95 The supply curve has been smoothed using a statistical technique that fits a smooth curve to the underlying supply curve data while ensuring that the point of intersection between supply and demand curves is at the market clearing price. The supply curve includes all offered MW while the prices on the supply curve reflect the smoothing method. The demand curve excludes incremental demand which cleared in DPL South.

96 Rules for RPM auctions state that imports are modeled in the unconstrained region of the RTO. See PJM. "Manual 18: PJM Capacity Market," Revision 09 (June 1, 2010), p. 24.

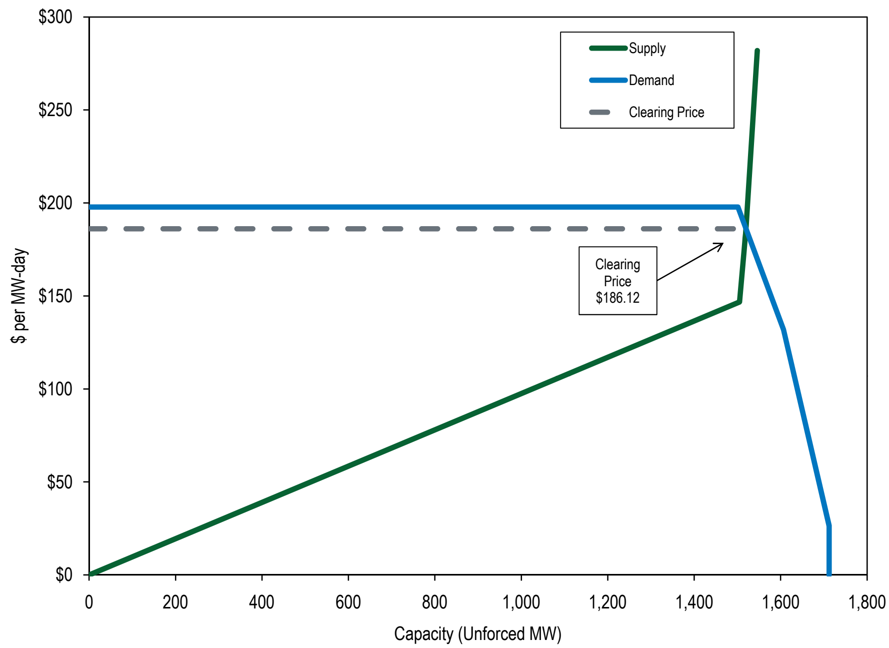
As shown in Table 5-18, the DPL zone net load price that LSEs will pay is $187.04 per MW-day. This value is the final zonal capacity price ($187.34 per MW-day) less the final CTR credit rate ($0.30 per MW-day). Prior to the 2012/2013 delivery year, the CTR MW value allocated to load in an LDA with a binding locational constraint is the Base Unforced Capacity imported into an LDA in the BRA for the delivery year less the import capability increase into the LDA attributable to Quality Transmission Upgrades (QTU) for the delivery year less the Incremental Capacity Transfer Rights that are allocated into the LDA for the delivery year, where the Base Unforced Capacity imported into an LDA is equal to the Base LDA UCAP obligation less the cleared unforced capacity in the BRA internal to the LDA less the ILR forecast for the LDA. This MW value is multiplied by the locational price adder for the LDA to arrive at the economic value of the CTRs allocated to the load in the LDA. This value is then divided by the LDA UCAP obligation to arrive at the final CTR credit rate for the LDA. The final CTR credit rate is an allocation of the economic value of transmission import capability that exists in constrained LDAs and serves to offset a portion of the locational price adder charged to load in constrained LDAs.

Table 5-18 DPL South offer statistics: 2010/2011 RPM Base Residual Auction[97]

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Total internal DPL South capacity (gen and DR)	1,652.3	1,546.1		
Imports	0.0	0.0		
RPM capacity	1,652.3	1,546.1		
Exports	0.0	0.0		
Excused	0.0	0.0		
Available	1,652.3	1,546.1	100.0%	100.0%
Generation offered	1,637.1	1,530.4	99.1%	99.0%
DR offered	15.2	15.7	0.9%	1.0%
Total offered	1,652.3	1,546.1	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO	1,625.6	1,519.7	98.4%	98.3%
Cleared in LDA	0.0	0.0	0.0%	0.0%
Total cleared	1,625.6	1,519.7	98.4%	98.3%
Make-whole	0.0	0.0	0.0%	0.0%
Uncleared	26.7	26.4	1.6%	1.7%
Reliability requirement		3,049.4		
Total cleared plus make-whole		1,519.7		
CETL		1,447.0		
Total resources		2,966.7		
ILR certified		97.2		
Net excess/(deficit)		14.5		
Resource clearing price ($ per MW-day)		$186.12		
DPL zone weighted average resource clearing price ($ per MW-day)		$178.57	A	
Final zonal capacity price ($ per MW-day)		$187.34	B	
Final zonal CTR credit rate ($ per MW-day)		$0.30	C	
Final zonal ILR price ($ per MW-day)		$178.27	A-C	
Net load price ($ per MW-day)		$187.04	B-C	

97 There is no separate zonal capacity price or CTR credit rate for DPL South as the DPL South LDA is completely contained within the DPL Zone.

Figure 5-3 DPL South supply/demand curves: 2010/2011 RPM Base Residual Auction[98]



2010/2011 RPM Third Incremental Auction

Under RPM, prior to January 31, 2010, the Third Incremental Auction was held in January prior to the start of the delivery year, and effective January 31, 2010, the Third Incremental Auction is held in February prior to the start of the delivery year.

RTO

Table 5-19 shows total RTO offer and bid data for the 2010/2011 RPM Third Incremental Auction. There were 4,553.9 MW offered into the incremental auction while buy bids totaled 5,221.0 MW. The offered volumes came from uncleared internal generation offers from the 2010/2011 BRA (598.2 MW), new generation (176.2 MW), reactivated generation (127.7 MW), capacity modifications (cap mods) to existing generation resources (534.5 MW), additional UCAP due to improved EFORds since the BRA (1,425.5 MW), replacements (-264.0 MW), locational UCAP transactions (-135.6 MW), imports (395.2 MW), DR offers (1,451.6 MW) less a net change in FRR commitments (-401.4 MW), a net change in exports (-114.4 MW), a net change in unoffered MW in the 2010/2011 BRA (270.2 MW), and excused generation (1.0 MW). Buy bids were submitted to cover short positions due to deratings and EFORd increases or because participants wished to purchase additional capacity. Cleared volumes in the RTO were 1,845.8 MW, resulting in an RTO clearing price of $50.00 per MW-day. The RTO clearing price in the 2010/2011 BRA was $174.29 per MW-day. The 2,708.1 MW of uncleared volumes can be used as replacement volumes or traded bilaterally.

98 The supply curve has been smoothed using a statistical technique that fits a smooth curve to the underlying supply curve data while ensuring that the point of intersection between supply and demand curves is at the market clearing price. The supply curve includes all offered MW while the prices on the supply curve reflect the smoothing method. The demand curve is reduced by the CETL.

Although DPL South was constrained in the 2010/2011 BRA, supply offers in the incremental auction in DPL South (56.8 MW) exceeded DPL South demand bids (25.9 MW). The offered volumes came from uncleared internal generation offers from the 2010/2011 BRA (25.6 MW), capacity modifications (cap mods) to existing generation resources (-2.2 MW), additional UCAP due to improved EFORds since the BRA (34.0 MW), and replacements (-0.6 MW). Supply and demand curves resulted in a price less than the RTO clearing price. The result was that all of DPL South supply which cleared received the RTO clearing price.

Cleared capacity resources across the entire RTO will receive a total of $33.7 million based on the unforced MW cleared and the prices in the 2010/2011 RPM Third Incremental Auction.

Table 5-19 RTO offer statistics: 2010/2011 RPM Third Incremental Auction

	Offered (Supply)		Bid (Demand)
	ICAP (MW)	UCAP (MW)	UCAP (MW)
Generation	3,274.3	3,102.3	
DR	1,402.9	1,451.6	
Total	4,677.2	4,553.9	5,221.0
Cleared in RTO	1,947.6	1,845.8	1,845.8
Cleared in LDAs	0.0	0.0	0.0
Total cleared	1,947.6	1,845.8	1,845.8
Uncleared in RTO	2,729.6	2,708.1	3,375.2
Uncleared in LDAs	0.0	0.0	0.0
Total uncleared	2,729.6	2,708.1	3,375.2
Resource clearing price ($ per MW-day)		$50.00	

Incremental Auction Design

Prior to the 2012/2013 delivery year, the First and Third Incremental Auctions are conducted to allow capacity resource providers to buy and sell capacity to accommodate adjustments to resource positions as a result of capacity and DR modifications to existing capacity resources, new capacity resources, resource retirements, resource cancellations or delays, changes in a generation resource's equivalent demand forced outage rate (EFORd), or cancellations or delays of a Qualifying Transmission Upgrade. For the 2012/2013 delivery year and beyond, Incremental Auctions are conducted to allow for replacement resource procurement, procurement or release of capacity due to reliability requirement adjustments, and deferred Short-Term Resource Procurement. Prior to the 2012/2013 delivery year, the demand curve in the Third Incremental Auction is entirely a function of resource provider demand bids, and there is no administrative market demand curve. Effective with the 2012/2013 delivery year, the demand curves in the First, Second, and Third Incremental Auctions may be comprised of

- buy bids submitted by participants;

- a portion of the Updated VRR Curve Increment to procure capacity equal to the Short-Term Resource Procurement Applicable Share (STRPTAS) plus the increase in the reliability requirement, if the PJM or LDA reliability requirement increases from the most recent prior auction conducted for the delivery year by more than the lesser of 500 MW or one percent of the applicable prior reliability requirement for First and Second Incremental Auctions and by a threshold of zero for Third Incremental Auctions;

- a portion of the Updated VRR Curve Increment to procure capacity equal to the STRPTAS plus the decrease in the reliability requirement if the PJM or LDA reliability requirement decreases by more than the lesser of 500 MW or one percent of the applicable prior reliability requirement for First and Second Incremental Auctions and by a threshold of zero for Third Incremental Auctions and the decrease in the reliability requirement exceeds the STRPTAS; or

- the entire Updated VRR Curve Increment if the updated PJM or LDA reliability requirement less the Short-Term Resource Procurement Target used in the most recent auction conducted for the delivery year exceeds the total capacity committed in all prior auctions for the delivery year by an amount greater than or equal to the lesser of 500 MW or one percent of the applicable prior reliability requirement.[99,100]

The STRPTAS is equal to 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction for First and Second Incremental Auctions and 0.6 times the Short-Term Resource Procurement Target used in the Base Residual Auction for Third Incremental Auctions. The Updated VRR Curve Increment is the portion of the Updated VRR Curve, updated to reflect the Short-term Resource Procurement Target applicable to the relevant Incremental Auction and any change in the Reliability Requirement, to the right of the vertical line at the level of unforced capacity (UCAP) commitments for the delivery year. Prior to the 2012/2013 delivery year, supply curves in RPM Incremental Auctions are entirely a function of participant sell offers. Effective with the 2012/2013 delivery year, the supply curves in the First, Second, and Third Incremental Auction may be comprised of

- sell offers submitted by participants;

- or a portion of the Updated VRR Curve Decrement to procure capacity equal to the STRPTAS plus the decrease in the reliability requirement if the PJM or LDA reliability requirement decreases from the most recent prior auction conducted for the delivery year by more than the lesser of 500 MW or one percent of the applicable prior reliability requirement or First and Second Incremental Auctions and a threshold of zero for Third Incremental Auctions and the decrease in the reliability requirement exceeds the STRPTAS.

The Updated VRR Curve Decrement is the portion of the Updated VRR Curve, updated to reflect the Short-term Resource Procurement Target applicable to the relevant Incremental Auction and any change in the Reliability Requirement, to the left of the vertical line at the level of unforced capacity commitments for the delivery year.

99 For the rules relating to the tests used to determine if PJM must procure or release capacity, see OATT Attachment DD: Reliability Pricing Model, § 5.4 (c).
100 For the rules used to determine the MW quantities and prices of PJM buy bids and sell offers, see OATT Attachment DD: Reliability Pricing Model, § 5.12 (b).

Reliability Must Run Units

Part V of the PJM Tariff provides for reliability and market power analyses of power plants proposed for deactivation.[101] An owner may deactivate, meaning either a retirement or mothball, with 90 days notice.[102] PJM performs a reliability analysis to determine whether deactivation would "adversely affect the reliability of the Transmission System absent upgrades," and, if it identified an adverse effect, "an estimate of the … time it will take to complete the … upgrades ..."[103] The MMU analyzes the "effect of the proposed deactivation with regard to market power issues."[104] If PJM determines that a unit is needed for reliability, it would request that the unit provide reliability must run (RMR) service.[105]

The tariff does not require owners to provide RMR service. An owner that agrees to provide RMR service may collect its costs under a formula rate provided in Part V.[106] This rate accounts for "deactivation avoidable costs."[107] An owner may, in the alternative, file with FERC to "recover the entire cost of operating the generating unit."[108]

RMR Service represents a period of post market operations for a unit. During the prior period of market operations, the owner has invested in, maintained and marketed the unit and has obtained the best return it could through a market design that is regulated through competition. Under regulation through competition, the owner does not have to show that its profits are justified by the costs incurred, but it also bears the risks to recover its costs. RMR service is a consequence of the owner's decision to exit the market when it makes a determination that the unit is no longer economic but the system operator, PJM, has determined that continued service is needed for reliability. Ratepayers and not the owner appropriately bear all of the additional costs that the unit owner would not have incurred if the unit owner had deactivated its unit as it proposed. The entire cost of any additional investment necessary to continue operating during the period of RMR service is appropriately borne by ratepayers. Those costs include a return on and of any additional capital investment required to fulfill the RMR agreement and approved by PJM. Ratepayers should not bear any of the costs incurred that preceded the decision to retire. Those costs were incurred by the owner based on the owner's full responsibility for the consequences. The owner was entitled to any level of profits that investment generated and it also bore the risk of a disappointing return or even a loss. RMR service is not a reason to undo the prior terms of service.

In 2010, PJM and the MMU evaluated 12 proposed deactivations. These included: AEP – Sporn 5; AMP – Gorsuch; Dominion – Altavista (Hall Branch); Dominion – Chesapeake GT 7; Dominion – North Branch; Exelon – Cromby Diesel 98; Exelon – Cromby Unit No. 2; Exelon – Eddystone Unit No. 2; First Energy – RE Berger 4&5; Ingenco – Petersburg; MM Hackensack – Baleville and Kingsland; NRG – Indian River 3; and VMEU – Vineland 9.[109]

101 OATT § 113.2.
102 OATT § 113.1.
103 OATT § 113.2.
104 OATT § Attachment M–Appendix § IV.1.
105 OATT § 113.2.
106 OATT §§ 114, 115.
107 *Id.*
108 OATT § 113.2, 119.
109 In addition, PJM evaluated the deactivation request for Ingenco – Richmond.

On December 9, 2009, Exelon Generation Company notified PJM of its intent to retire its Cromby Unit No. 2 (Cromby) and Eddystone Unit No. 2 (Eddystone), effective May 31, 2011. The MMU determined that the proposal did not raise market power issues. PJM determined that the units would be needed until December 31, 2011, (Cromby) and December 31, 2012, (Eddystone), in order to provide time for the system to add upgrades necessary to accommodate the retirements.

Exelon agreed to provide RMR service and determined to file for the recovery of its RMR costs directly with the FERC under section 119 of the PJM tariff.[110] In pleadings filed on July 15, August 13 and September 13, 2010, the MMU argued to the FERC that the filing was deficient, particularly with respect to the support offered for the proposed treatment of depreciated capital investment costs, and requested that the FERC institute a process to consider the issue.[111] The MMU explained that it appeared that Exelon Generation proposed to fully recover during the period of RMR service investment costs made prior to the decision to retire. By order issued September 16, 2010, the Commission set the matter for hearing, but held the hearing in abeyance pending settlement discussions.[112] The MMU, Exelon Generation Company, FERC trial staff, public advocates and consumer representatives have actively participated in settlement discussion, and the Settlement Judge reported on December 15, 2010, that the parties "have reached a settlement in principle."[113]

The Exelon proceeding raises questions about whether PJM has a consistent and fair approach to RMR service. An initial question is whether it is appropriate for RMR service to be voluntary, even if, as a practical matter, owners have been cooperative with PJM about extending service to accommodate reliability needs. All stakeholders have a shared interest in reliability, and it should not impose any hardship on generator owners if their costs are fully covered during the RMR period of service. An obligation to provide RMR service could be reasonably conceived as a term and condition of receiving interconnection service in an organized wholesale market.

Another issue is the appropriate treatment of costs in RMR filings. Sections 114 and 115 of the PJM tariff unambiguously limit recovery to "avoidable costs." Perhaps as a consequence, owners have to date sought recovery directly from the FERC under section 119 of the OATT.[114] This section refers to collecting the "entire cost of operating the generating unit." Avoidable costs means costs that would not have been incurred but for continued operation of the unit. Some have read the phrase "entire cost of operating the generating unit" as a justification for recovery of pre-notification sunk fixed costs in addition to avoidable costs.

Ambiguity about what costs are eligible for recovery has encouraged owners to file to recover all of their depreciated costs during what is typically a relatively short period of RMR service. The Market Monitor is concerned about the implications of this approach. Owners should not be permitted to transfer risks assumed while participating in competitive markets simply because the system is not ready to accommodate a retirement proposed with as little as 90 days notice. If this were permitted, RMR service could become a stratagem for depriving customers of one the key benefits of restructuring, the shifting of investment risks to suppliers and away from ratepayers. To date, the

110 See Exelon Generation Company, LLC filing in FERC Docket No. ER10-1418 (June 10, 2010).

111 "Comments and Motion for Technical Conference of the Independent Market Monitor for PJM," "Motion for Leave to Answer and Answer of the Independent Market Monitor for PJM," "Motion for Leave to Answer and Answer of the Independent Market Monitor for PJM [2nd]," filed in Docket No. ER10-1418.

112 132 FERC ¶ 61,219.

113 Settlement Status Report, Judge Birchman, Docket No. ER10-1418.

114 See Hudson Unit No. 1 and Sewaren Units Nos. 1–4 (Docket No. ER05-644), Brunot Island Units Nos. CT2A, CT2B, CT3 and CC4 (ER07-859).

number of retirements has been manageable, but there is the potential for a significant increase in retirements.

The MMU recommends that the two approaches to RMR cost recovery included in the current rules be clarified and made consistent. The theory of recovery should be same under either approach, and it should be based on avoidable costs. Units needed for RMR service have market power because only the identified unit(s) can provide the required reliability.

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 hours when units are needed to operate by the system operator (generator forced outage rates).[115]

Generator Performance Factors

Generator performance factors are based on a defined period, usually a year, and are directly comparable.[116] Performance factors include the equivalent availability factor (EAF), the equivalent maintenance outage factor (EMOF), the equivalent planned outage factor (EPOF) and the equivalent forced outage factor (EFOF). These four factors add to 100 percent for any generating unit. The EAF is the proportion of hours in a year when a unit is available to generate at full capacity while the three outage factors include all the hours when a unit is unavailable. The EMOF is the proportion of hours in a year when a unit is unavailable because of maintenance outages and maintenance deratings. The EPOF is the proportion of hours in a year when a unit is unavailable because of planned outages and planned deratings. The EFOF is the proportion of hours in a year when a unit is unavailable because of forced outages and forced deratings.

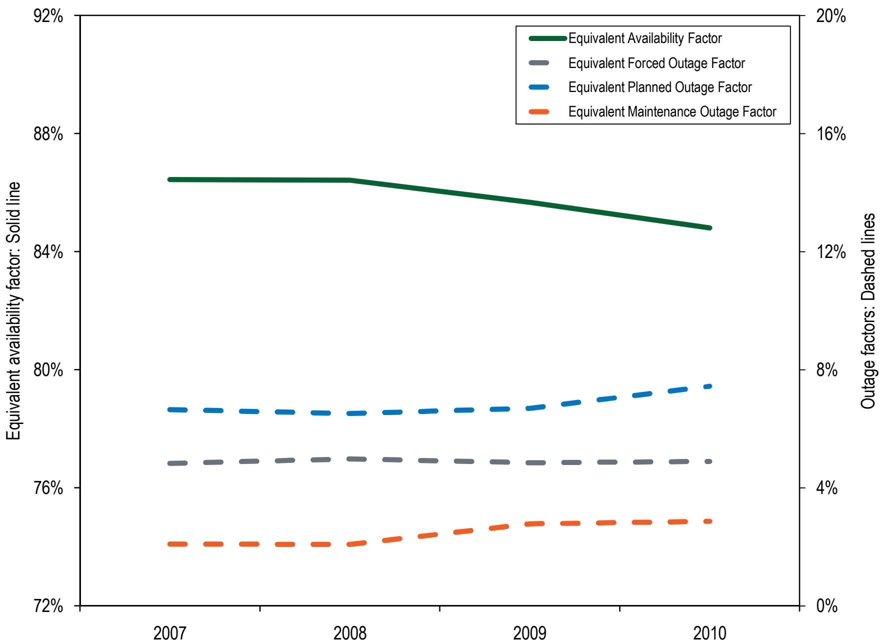
The PJM aggregate EAF decreased from 85.7 percent in 2009 to 84.8 percent in 2010. The EMOF increased from 2.8 percent in 2009 to 2.9 percent in 2010, the EPOF increased from 6.7 percent in 2009 to 7.4 percent in 2010, and the EFOF increased from 4.8 percent in 2009 to 4.9 percent in 2010 (Figure 5-4).[117]

115 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.

116 Data from all PJM capacity resources for the years 2007 through 2010 were analyzed.

117 Data are for the calendar year ending December 31, 2010, as downloaded from the PJM GADS database on January 21, 2011. Annual 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.

Figure 5-4 PJM equivalent outage and availability factors: Calendar years 2007 to 2010



Generator Forced Outage Rates

The equivalent demand forced outage rate (EFORd) (generally referred to as the forced outage rate) 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 is calculated using historical performance data. PJM systemwide EFORd is a capacity-weighted average of individual unit EFORd. Unforced capacity in the PJM Capacity Market for any individual generating unit is equal to one minus the EFORd adjusted to exclude Outside Management Control (OMC) events multiplied by the unit's net dependable summer capability.[118] The PJM Capacity Market creates an incentive to minimize the forced outage rate because the amount of capacity resources available to sell from a unit (unforced capacity) is inversely related to the forced outage rate.

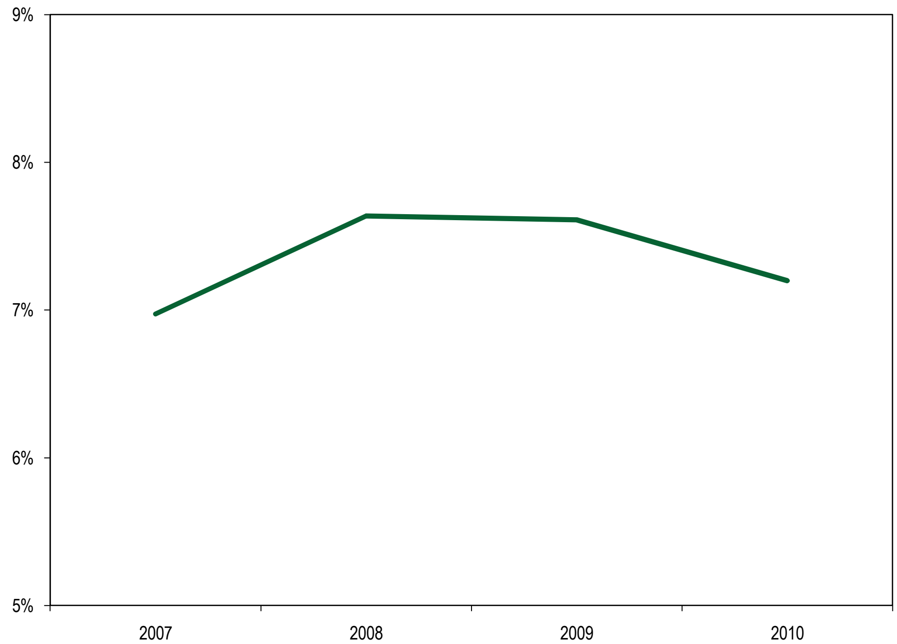
EFORd calculations use historical data, including equivalent forced outage hours,[119] service hours, average forced outage duration, average run time, average time between unit starts, available hours and period hours.[120] The average PJM EFORd changed from 7.0 percent in 2007 to 7.6 percent in 2008 and 2009 to 7.2 percent in 2010. Figure 5-4 shows the average EFORd since 2007 for all units in PJM. The decreases in both EFORd and EAF in 2010 are consistent. EAF decreased as a result of the increase in EPOF, the EMOF and the EFOF. EFORd, on the other hand, describes the forced outage rate during periods of demand, which is a subset of the hours included in EFOF and does not include planned or maintenance outages.

118 EFORd adjusted to exclude Outside Management Control (OMC) events is defined as XEFORd.

119 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.

120 See "Manual 22: Generator Resource Performance Indices," Revision 15 (June 1, 2007), Equations 2 through 5.

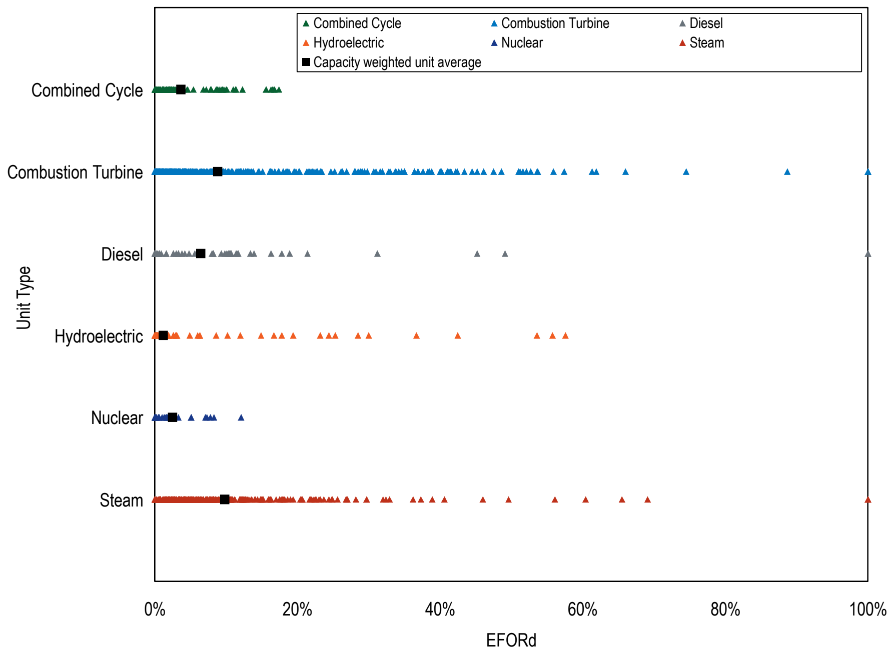
Figure 5-5 Trends in the PJM equivalent demand forced outage rate (EFORd): Calendar years 2007 to 2010



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 5-6. Each generating unit is represented by a single point, and the capacity weighted unit average is represented by a solid square. Diesel and combustion turbine units have the greatest variance of EFORd, while nuclear and combined cycle units have the lowest variance in EFORd values.

Figure 5-6 PJM 2010 Distribution of EFORd data by unit type



Components of EFORd

Table 5-20 compares PJM EFORd data by unit type to the five-year North American Electric Reliability Council (NERC) average EFORd data for corresponding unit types. The 2010 PJM forced outage rates for combined cycle, combustion turbine, diesel, hydroelectric and nuclear units were below the NERC five-year averages. The 2010 PJM EFORd for fossil steam units exceeded the NERC average.[121]

Table 5-20 PJM EFORd data comparison to NERC five-year average for different unit types: Calendar years 2007 to 2010

	2007	2008	2009	2010	NERC EFORd 2005 to 2009 Average
Combined Cycle	3.7%	3.8%	4.2%	3.7%	5.9%
Combustion Turbine	11.0%	11.1%	9.9%	8.8%	9.1%/8.9%
Diesel	11.9%	10.4%	9.3%	6.5%	13.0%
Hydroelectric	2.1%	2.0%	3.1%	1.2%	5.0%
Nuclear	1.4%	1.9%	4.1%	2.5%	3.1%
Steam	9.1%	10.1%	9.4%	9.8%	7.2%
Total	7.0%	7.6%	7.6%	7.2%	NA

Table 5-21 shows the contribution of each unit type to the system EFORd, calculated as the total forced MW for the unit type divided by the total capacity of the system.[122] Forced MW for a unit type is the EFORd multiplied by the generator's net dependable summer capability.

Table 5-21 Contribution to EFORd for specific unit types (Percentage points): Calendar years 2007 to 2010[123]

	2007	2008	2009	2010	Change in 2010 from 2009
Combined Cycle	0.4	0.5	0.5	0.4	(0.0)
Combustion Turbine	1.7	1.7	1.6	1.4	(0.2)
Diesel	0.0	0.0	0.0	0.0	(0.0)
Hydroelectric	0.1	0.1	0.1	0.0	(0.1)
Nuclear	0.3	0.4	0.8	0.5	(0.3)
Steam	4.4	5.0	4.7	4.8	0.2
Total	7.0	7.6	7.6	7.2	(0.4)

Steam units continue to be the largest contributor to overall PJM EFORd.

121 NERC defines combustion turbines in two categories: jet engines and gas turbines. The EFORd for the 2005 to 2009 period are 9.1 percent for jet engines and 8.9 percent for gas turbines per NERC's GADS "2005-2009 Generating Availability Report" <http://www.nerc.com/files/gar2009.zip> (2.58 MB). Also, the NERC average for fossil steam units is a unit-year-weighted value for all units reporting. The PJM values are weighted by capability for each calendar year.

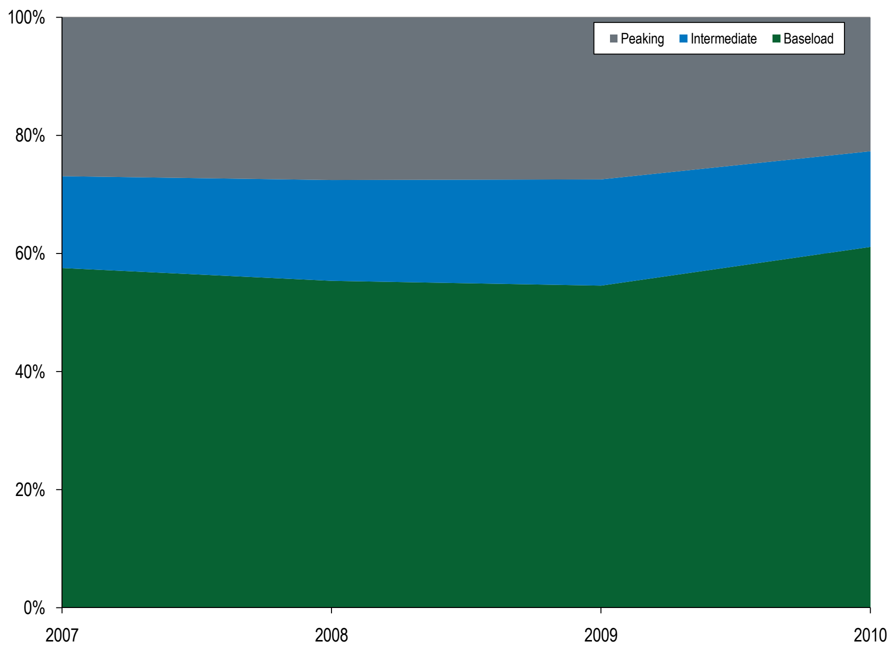
122 The generating unit types are: combined cycle, combustion turbine, diesel, hydroelectric, nuclear and steam. For all tables, run of river and pumped storage hydroelectric are combined into a single hydroelectric category.

123 Calculated values presented in Section 5, "Capacity Market" at "Generator Performance" are based on unrounded, underlying data and may differ from those derived from the rounded values shown in the tables.

Duty Cycle and EFORd

In addition to disaggregating system EFORd by unit type, units were categorized by actual duty cycles as baseload, intermediate or peaking to determine the relationship between type of operation and forced outage rates.[124] Figure 5-7 shows the contribution of unit types to system average EFORd. Total capacity in 2010 consists of 68.4 percent baseload capacity, 14.2 percent intermediate capacity, and 17.4 percent peak capacity.

Figure 5-7 Contribution to EFORd by duty cycle: Calendar years 2007 to 2010



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

2010 PJM EFOF was 4.9 percent. This means there was 4.9 percent lost availability because of forced outages. Table 5-22 shows that forced outages for boiler tube leaks, at 22.9 percent of the systemwide EFOF, were the largest single contributor to EFOF. Forced outages for economic

124 Duty cycle is the time the unit is generating divided by the time the unit is available to generate. A baseload unit is defined here as a unit that generates during 50 percent or more of its available hours. An intermediate unit is defined here as a unit that generates during from 10 percent to 50 percent of its available hours. A peaking unit is defined here as a unit that generates during less than 10 percent of its available hours.

125 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.

reasons, at 8.9 percent, were the second largest contributor to EFOF. Forced outages for electrical problems, at 6.6 percent, were the third largest contributor to EFOF.

Table 5-22 Contribution to EFOF by unit type by cause: Calendar year 2010

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	System
Boiler Tube Leaks	0.4%	0.0%	0.0%	0.0%	0.0%	29.2%	22.9%
Economic	1.7%	16.8%	9.6%	13.5%	0.0%	9.8%	8.9%
Electrical	8.7%	37.9%	3.3%	12.0%	10.6%	3.5%	6.6%
Boiler Air and Gas Systems	0.0%	0.0%	0.0%	0.0%	0.0%	7.2%	5.6%
Boiler Internals and Structures	0.5%	0.0%	0.0%	0.0%	0.0%	4.8%	3.8%
Boiler Fuel Supply from Bunkers to Boiler	0.0%	0.0%	0.0%	0.0%	0.0%	4.4%	3.4%
Feedwater System	2.8%	0.0%	0.0%	0.0%	6.6%	3.1%	3.2%
Circulating Water Systems	1.4%	0.0%	0.0%	0.0%	12.8%	2.0%	2.8%
Miscellaneous (Steam Turbine)	3.4%	0.0%	0.0%	0.0%	0.4%	3.0%	2.6%
Catastrophe	0.3%	0.5%	2.1%	7.6%	0.0%	2.7%	2.2%
Condensing System	1.1%	0.0%	0.0%	0.0%	7.4%	1.8%	2.1%
Fuel Quality	0.1%	0.0%	0.7%	0.0%	0.0%	2.4%	1.9%
Boiler Piping System	3.4%	0.0%	0.0%	0.0%	0.0%	2.1%	1.8%
Controls	2.5%	0.8%	0.9%	3.5%	5.7%	1.4%	1.8%
Stack Emission	0.0%	0.1%	0.2%	0.0%	0.0%	2.3%	1.8%
Boiler Tube Fireside Slagging or Fouling	0.0%	0.0%	0.0%	0.0%	0.0%	1.9%	1.5%
Auxiliary Systems	2.3%	4.2%	0.0%	0.9%	7.6%	0.4%	1.4%
Miscellaneous (Balance of Plant)	3.6%	1.6%	0.0%	6.7%	2.0%	1.1%	1.4%
Inlet Air System and Compressors	13.8%	5.9%	0.0%	0.0%	0.0%	0.0%	1.2%
All Other Causes	54.1%	32.3%	83.1%	55.7%	46.9%	16.9%	23.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Table 5-23 shows the categories which are included in the economic category.[126] Lack of fuel that is considered Outside Management Control accounted for 78.0 percent of all economic reasons while lack of fuel that was not Outside Management Control accounted for only 4.7 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"[127] and was used by 28 combined cycle, combustion turbine and steam units in 2010. 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.

126 The classification and definitions of these outages are defined by NERC GADS.
127 The classification and definitions of these outages are defined by NERC GADS.

Table 5-23 Contributions to Economic Outages: 2010

	Contribution to Economic Reasons
Lack of fuel (OMC)	78.0%
Other economic problems	16.1%
Lack of fuel (Non-OMC)	4.7%
Lack of water (Hydro)	0.9%
Fuel conservation	0.3%
Ground water or other water supply problems	0.0%
Total	100.0%

Table 5-24 Contribution to EFOF by unit type: Calendar year 2010

	EFOF	Contribution to EFOF
Combined Cycle	2.6%	6.4%
Combustion Turbine	1.9%	6.0%
Diesel	4.5%	0.2%
Hydroelectric	0.7%	0.6%
Nuclear	2.3%	8.5%
Steam	7.7%	78.4%
Total	4.9%	100.0%

The contribution to systemwide EFOF by a generator or group of generators is a function of duty cycle, EFORd and share of the systemwide capacity mix. For example, fossil steam units had the largest share (49.4 percent) of PJM capacity, had a high duty cycle and in 2010 had an EFORd of 9.8 percent which yields a 78.4 percent contribution to PJM systemwide EFOF. Nuclear units had an 18.4 percent share of PJM capacity, had a high duty cycle, and in 2010 had an EFORd of 2.5 percent which yields an 8.5 percent contribution to PJM systemwide EFOF. Using the values in Table 5-24 the contribution of individual unit type causes to PJM systemwide EFOF can be determined. For example, the value for boiler tube leaks in Table 5-22 multiplied by the contribution value in Table 5-24 for the same unit type will yield the percent contribution to the EFOF for that outage cause. Boiler tube leaks contributed 29.2 percent of the EFOF for steam units, total EFOF for steam units was 7.7 percent, which means that boiler tube leaks account for 1.4 percentage points of the 7.7 percent steam unit EFOF.

Outages Deemed Outside Management Control

In 2006, NERC created specifications for certain types of outages to be deemed Outside Management Control (OMC).[128] 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 (i.e., codes that are standardized for specific outage causes) that would be considered OMC outages.[129] Not all outages caused by the factors in these specific OMC cause codes are OMC outages. For example, fuel quality issues (i.e., codes 9200 to 9299) may be within the control of the owner or outside management control. Each outage must be considered per the NERC directive.

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 used to determine the level of unforced capacity for specific units that must be offered in PJM's Capacity Market. This modified EFORd is termed the XEFORd.

Table 5-25 shows OMC forced outages by cause code. OMC forced outages account for approximately 10.6 percent of all forced outages. The largest contributor to OMC outages, lack of fuel, is the cause of 65.6 percent of OMC outages and 6.9 percent of all forced outages. The NERC GADS guidelines in Appendix K describe OMC lack of fuel as "lack of fuel where the operator is not in control of contracts, supply lines, or delivery of fuels." Of the OMC lack of fuel outages in 2010, 98.8 percent of the outages were submitted by units operated by a single owner.

It is questionable whether the OMC outages defined as lack of fuel should be identified as OMC and excluded from the calculation of XEFORd and EFORp. All submitted OMC outages are reviewed by PJM's Resource Adequacy Department. The MMU recommends that PJM review all requests for OMC carefully, develop a transparent set of rules governing the designation of outages as OMC and post those guidelines. The MMU also recommends that PJM consider eliminating lack of fuel as an acceptable basis for an OMC outage.

128 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> (4.9 MB).

129 For a list of these cause codes, see the *Technical Reference for PJM Markets,* Section 2, "Capacity Market."

Table 5-25 OMC Outages: Calendar year 2010

OMC Cause Code	% of OMC Forced Outages	% of all Forced Outages
Lack of fuel	65.6%	6.9%
Flood	11.9%	1.3%
Other catastrophe	8.2%	0.9%
Switchyard circuit breakers external	3.9%	0.4%
Transmission equipment beyond the 1st substation	3.2%	0.3%
Other switchyard equipment external	1.6%	0.2%
Switchyard system protection devices external	1.5%	0.2%
Transmission system problems other than catastrophes	1.3%	0.1%
Lack of water (hydro)	0.7%	0.1%
Other miscellaneous external problems	0.6%	0.1%
Lightning	0.6%	0.1%
Storms (ice, snow, etc)	0.3%	0.0%
Transmission line (connected to powerhouse switchyard to 1st Substation)	0.1%	0.0%
Fire, not related to a specific component	0.1%	0.0%
Low BTU coal	0.1%	0.0%
Switchyard transformers and associated cooling systems external	0.0%	0.0%
Transmission equipment at the 1st substation	0.0%	0.0%
Miscellaneous regulatory	0.0%	0.0%
Total	100.0%	10.6%

Table 5-26 shows the impact of OMC outages on EFORd for 2010. The difference is especially noticeable for steam units and combustion turbine units. For steam units, the OMC outage reason that resulted in the highest total MW loss in 2010 was lack of fuel. Combustion turbine units have natural gas fuel curtailment outages that were also classified as OMC. If companies' natural gas fuel supply is curtailed because of pipeline issues, the event can be deemed OMC. However, natural gas curtailments caused by lack of firm transportation contracts or arbitraging transportation reservations should not be classified as OMC. In 2010, steam XEFORd was 1.3 percentage points less than EFORd, which translates into a 1,085 MW difference in unforced capacity.

Table 5-26 PJM EFORd vs. XEFORd: Calendar year 2010

	2010 EFORd	2010 XEFORd	Difference
Combined Cycle	3.7%	3.5%	0.1%
Combustion Turbine	8.8%	6.9%	1.9%
Diesel	6.5%	4.5%	2.0%
Hydroelectric	1.2%	0.9%	0.3%
Nuclear	2.5%	2.5%	0.0%
Steam	9.8%	8.5%	1.3%
Total	7.2%	6.2%	1.0%

Components of 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.

Table 5-27 shows the contribution of each unit type to the system EFORp, calculated as the total forced MW for the unit type divided by the total capacity of the system. Forced MW for a unit type is the EFORp multiplied by the generator’s net dependable summer capability.

Table 5-27 Contribution to EFORp by unit type (Percentage points): Calendar years 2009 to 2010

	2009	2010
Combined Cycle	0.4	0.4
Combustion Turbine	0.4	0.4
Diesel	0.0	0.0
Hydroelectric	0.1	0.0
Nuclear	0.8	0.5
Steam	2.3	3.8
Total	4.0	5.2

Table 5-28 PJM EFORp data by unit type: Calendar years 2009 to 2010

	2009	2010
Combined Cycle	3.4%	3.0%
Combustion Turbine	2.5%	2.7%
Diesel	4.4%	3.3%
Hydroelectric	2.9%	1.1%
Nuclear	4.2%	2.9%
Steam	4.7%	7.7%
Total	4.0%	5.2%

EFORd, XEFORd and 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.[130] 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 within their control to do so. That is consistent with the incentives created by the PJM Capacity Market. EFORp of nuclear units is slightly higher than EFORd and XEFORd, suggesting that nuclear units have a slightly higher rate of forced outages during the peak months of January, February, June, July and August.

Table 5-29 shows the contribution of each unit type to the system EFORd, XEFORd and EFORp, calculated as the total forced MW for the unit type divided by the total capacity of the system. Table 5-30 shows the capacity-weighted class average of EFORd, XEFORd and EFORp.

Table 5-29 Contribution to PJM EFORd, XEFORd and EFORp by unit type: Calendar year 2010

	EFORd	XEFORd	EFORp
Combined Cycle	0.4	0.4	0.4
Combustion Turbine	1.4	1.1	0.4
Diesel	0.0	0.0	0.0
Hydroelectric	0.0	0.0	0.0
Nuclear	0.5	0.5	0.5
Steam	4.8	4.2	3.8
Total	7.2	6.2	5.2

130 See "Manual 22: Generator Resource Performance Indices," Revision 15 (June 1, 2007), Definitions.

Table 5-30 PJM EFORd, XEFORd and EFORp data by unit type: Calendar year 2010[131]

	EFORd	XEFORd	EFORp	Difference EFORd and XEFORd	Difference EFORd and EFORp
Combined Cycle	3.7%	3.5%	3.0%	0.1%	0.7%
Combustion Turbine	8.8%	6.9%	2.7%	1.9%	6.1%
Diesel	6.5%	4.5%	3.3%	2.0%	3.2%
Hydroelectric	1.2%	0.9%	1.1%	0.3%	0.1%
Nuclear	2.5%	2.5%	2.9%	0.0%	(0.4%)
Steam	9.8%	8.5%	7.7%	1.3%	2.1%
Total	7.2%	6.2%	5.2%	1.0%	2.0%

Comparison of Expected and Actual Performance

If the unit EFORd were normally distributed and if EFORd based planning assumptions were consistent with actual unit performance, the distribution of actual performance would be identical to a hypothetical normal distribution based on average EFORd performance. There are a limited number of units within each unit type and the distribution of EFORd may not be a normal distribution.

This analysis was performed based on resource-specific EFORd and Summer Net Capability capacity values for the year ending December 31, 2010. [132] These values were used to estimate a normal distribution for each unit type,[133] which was superimposed on a distribution of actual historical availability for the same resources for the year ending December 31, 2010.[134] The top thirty load days were selected for each year and the performance of the resources was evaluated for the peak hour of those days, a sample of 30 peak load hours.

Figure 5-8 compares the normal distribution to the actual distribution based on the defined sample.

Overall, generating units performed better during the selected peak hours than would have been expected based on the EFORd statistic. In particular, CT and ST units tend to have more capacity available during the sampled hours than implied by the EFORd statistic.

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

132 See "Manual 21: Rules and Procedures for Determination of Generating Capability," Revision 08 (January 1, 2010), Summer Net Capability.

133 The formulas used to approximate the parameters of the normal distribution are defined as:

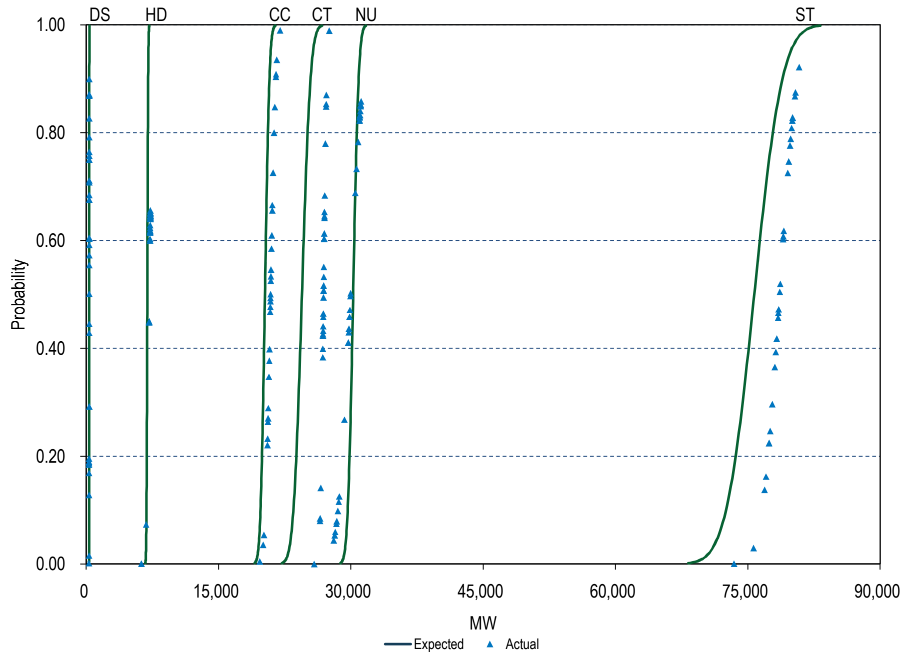
$$\text{Mean} = \sum_i \left[\text{MW}_i * \left(1 - \text{EFORd}_i\right)\right]$$

$$\text{Variance} = \sum_i \left[\text{MW}_i * \text{MW}_i * \left(1 - \text{EFORd}_i\right) * \text{EFORd}_i\right]$$

$$\text{Standard Deviation} = \sqrt{\text{Variance}}$$

134 Availability calculated as net dependable capacity affected only by forced outage and forced derating events. Planned and maintenance events were excluded from this analysis.

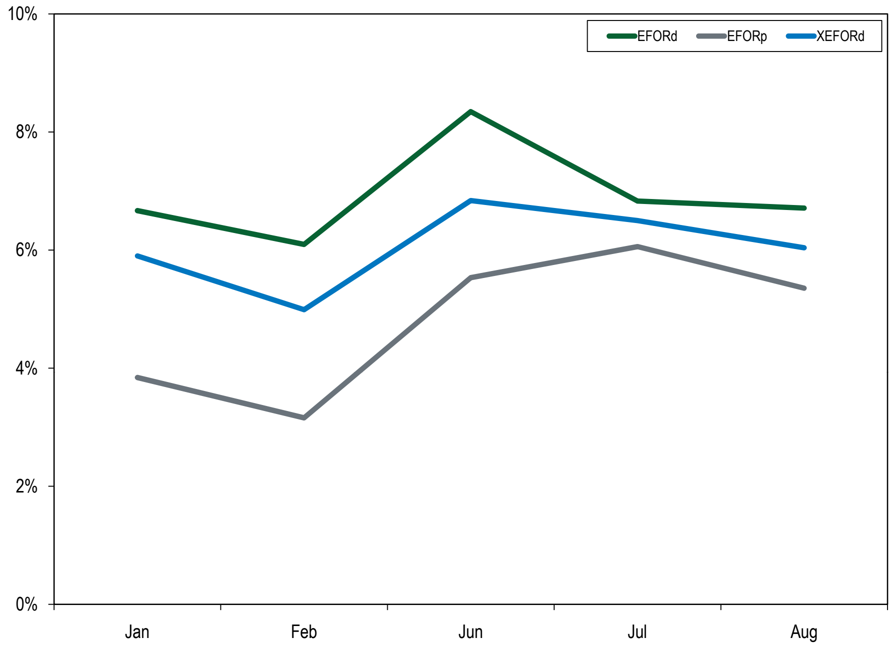
Figure 5-8 PJM 2010 distribution of EFORd data by unit type



Performance During Peak Months

For the peak months of January, February, June, July and August, EFORp values were significantly less than EFORd and XEFORd values as shown in Figure 5-9. EFORd during the peak months ranged from 6.1 percent to 8.3 percent, which is around the average for the year of 7.2 percent.

Figure 5-9 PJM EFORd, XEFORd and EFORp for the peak months of January, February, June, July and August: 2010



During the peak months of January, February, June, July and August, unit availability as measured by the equivalent availability factor increased, primarily due to decreasing planned outages, as illustrated in Figure 5-10. EAF during the peak months ranged from 89.0 percent to 91.1 percent, which is significantly higher than the average for the year of 84.8 percent.

Figure 5-10 PJM peak month generator performance factors